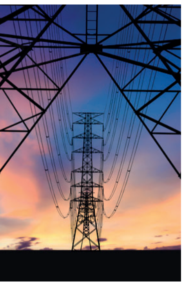
HERBERT SMITH FREEHILLS

EUROPEAN ENERGY HANDBOOK

A SURVEY OF THE LEGAL FRAMEWORK AND CURRENT ISSUES IN THE EUROPEAN ENERGY SECTOR

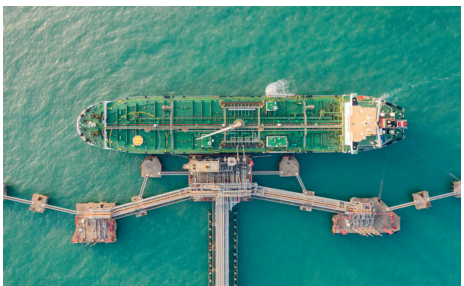
LEGAL GUIDE
TWELFTH EDITION

2023 – 2024







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Foreword

Welcome to the 2023/2024 edition of the European Energy Handbook!

I am delighted to introduce the 2023/2024 edition of "The European Energy Handbook", which provides an in-depth survey of current issues in the energy sector in 41 jurisdictions.

This year's edition focuses on recent legal and commercial developments within these jurisdictions and, for the EU as a whole, covers issues such as the REPower EU strategy, which, following Russia's invasion of Ukraine, the EU introduced with the aim of reducing the EU's dependence on Russian fossil fuels. This edition also covers other developments in EU energy policy and strategy, such as the EU's adoption of the European Green Deal, a package of concrete policy initiatives aimed at achieving net zero greenhouse gas emissions in the EU by 2050, Fit for 55, which is a set of proposals revising and updating EU legislation that aims to ensure the EU reaches its intermediate targets for 2030, and the revision of the design of the EU electricity market.

Climate change, the energy transition and associated challenges continue to be strong themes in nearly all of the contributions of this edition – as each jurisdiction strives to meet its EU renewable energy obligations by 2030 and beyond. Other topics in this edition include the ever increasing importance for the role of electricity storage in the energy mix, the more evident progress of privatisations in some jurisdictions, the development and construction of new electricity interconnectors and the emergence of multi-purpose interconnectors to enable the multi-jurisdictional connections of offshore wind projects, the growth in investment in alternative renewable sources such as hydrogen, and the ever increasing importance in the consideration of environmental, social and governance obligations in the energy world.

As always, I am grateful to the colleagues across Europe who have contributed to this edition:

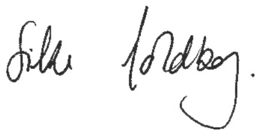
In addition to contributions for the European Union, Belgium, France, Germany, Ireland, Italy, Spain, and the United Kingdom from our own offices, this year we have contributions from Schönherr (Austria, Bulgaria, Croatia, Czech Republic, Hungary, Moldova, Montenegro, Romania, Serbia, Slovakia and Slovenia), Loloci & Associates (Albania), Georgiades & Pelides LLC (Cyprus), BOPA Law (Denmark), Ellex Raidla (Estonia), Roschier (Finland), Kyriakides Georgopoulos (Greece), BBA//Fjeldco (Iceland), Meitar Liquornik Geva Leshem Tal Law Offices (Israel), Kinstellar (Kazakhstan), Cobalt (Latvia and Lithuania), Arendt & Medernach (Luxembourg), Zammit Pace Advocates (Malta), Houthoff (the Netherlands), Karanovic & Partners (North Macedonia), Arntzen de Besche Advokatfirma AS (Norway), WKB Wierciński, Kwieciński, Baehr (Poland), Campos Ferreira, Sá Carneiro & Associados (Portugal), Setterwalls (Sweden), Schellenberg Wittmer AG (Switzerland), Kolcuoğlu Demirkan Koçaklı (Turkey), and Avellum (Ukraine).

Finally, special thanks are due to Barbara McNulty and Jesse Bakare who have worked tirelessly to make this edition of the European Energy Handbook a reality and without whom this project would not have been possible.

Happy reading and best wishes,

Silke Goldberg

Partner, Herbert Smith Freehills LLP
July 2023



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Recent developments in the European Union energy market

Silke Goldberg, partner, Jannis Bille, senior associate, Barbara McNulty, Marie Badr, both associates, and Maximilian Ketnath, trainee, all of Herbert Smith Freehills

REPowerEU

Russia's invasion of Ukraine has had a significant impact on the energy market, both globally and in the EU as Russia had been a major gas and oil supplier for EU countries. In the course of 2022, imports of gas from Russia declined continuously and in the third quarter of 2022, Russian pipeline gas imports fell by 74% compared to the previous year.

Gas prices increased in the third quarter of 2022, leading to an historic price spike. The daily average price at the Dutch Title Transfer Facility rose from €146/MWh in early July 2022 to an all-time high €320/MW on 26 August 2022.[1] In parallel, electricity prices were 222% higher in the third quarter of 2022 (€339/MWh), compared to 2021.[2]

In response to the developments on the energy markets, the European Commission (the "Commission") introduced the REPowerEU strategy, which aims to reduce the EU's dependence on Russian fossil fuels. The core sets of actions set out under the strategy are:

- saving energy;
- diversifying supply; and
- substituting fossil fuels with renewable energy sources.

Increased renewable energy targets

With REPowerEU the Commission introduced increased targets for the share of renewable energies as part of RED III. The proposal raised the original target envisaged under Fit for 55 (see below) from 40% to 42.5% with the ambition to reach 45% by 2030. The European Council (the "Council") and the European Parliament (the "Parliament") reached a provisional agreement to increase the targets as proposed by the Commission.

EU Energy Platform

The EU Energy Platform[3] was introduced in 2022 as part of the EU's diversification efforts under REPowerEU. The platform aims to increase the cooperation between the Commission, EU countries and industry to prevent EU countries from outbidding each other.

A mechanism has been introduced where volumes of gas are aggregated and put to tender on global markets ("AggregateEU"). Under the AggregateEU mechanism EU countries must aggregate 15% of their storage filling obligations and match demand with the most competitive offers from international suppliers. The mechanism is aimed to reduce price volatility and ensure secure supply of energy in the EU.

Funding of REPowerEU

To finance REPowerEU, the Commission proposed an amendment to the Recovery and Resilience Facility,[4] originally implemented to mitigate the economic and social impact of the coronavirus pandemic, to integrate dedicated REPowerEU chapters.[5]

It is expected that an additional investment of €210 billion is needed up to 2027 to phase out Russian fossil fuel imports.

EU solar energy strategy

The Commission presented its EU Solar Energy Strategy[6] on the same day as REPowerEU, describing it as a crucial element in reaching the REPowerEU goals.

The strategy presents four initiatives:

- accelerating solar energy deployment via the European Solar Rooftops Initiative;
- making permitting procedures shorter and simpler;
- ensuring availability of a skilled workforce; and
- launching a European Solar PV Industry Alliance.

The plan is to accelerate the solar energy deployment from 18GW in 2020 to 45GW per year by 2030.

The European Solar Rooftops Initiative[7] was introduced by the Commission as part of the EU Solar Energy Strategy. The initiative includes proposals for provisions to ensure that all new buildings are 'solar ready'. Other provisions under the initiative include requirements to make the installation of rooftop solar energy compulsory for:

- all new public and commercial buildings with a useful floor area larger than 250m^2 by 2026;
- all existing public and commercial buildings with a useful floor area larger than 250m^2 by 2027; and
- all new residential buildings by 2029.

The solar energy strategy aims for expedient deployment of solar energy across the EU. Solar energy is considered to be the 'kingpin' of the energy transition due to its low costs relative to other forms of renewable energy production.

European green deal and European climate law

The European Green Deal[8] is a package of concrete policy initiatives aiming for net zero greenhouse gas ("GHG") emissions in the EU by 2050, which addresses the areas of climate, environment, energy transport, industry, agriculture and sustainable finance. This net zero goal became legally binding under the European Climate Law,[9] which also sets the intermediate target of reducing net GHG emissions by at least 55% by 2030 compared to 1990 levels.

One of the many initiatives under the European Green Deal is the 'European Green Deal Industrial Plan'[10] presented by the Commission, which aims to strengthen the competitiveness of Europe's net-zero industry and support the transition to climate neutrality. The plan sets out the Commission's proposals to:

- simplify the regulatory framework for net-zero innovations;
- introduce faster access to funding;
- support the training of skilled worker in the Green Industry; and
- help building more resilient supply chains.

To further the plan's industry related proposals, a Net-Zero Industry Act has been proposed which aims at translating parts of the European Green Deal Industrial Plan initiatives into binding law.[11]

Fit for 55

A significant part of the European Green Deal is the 'fit for 55' package ("Fit for 55")[12].

Further to the obligation under the European Climate Law that all EU policies must contribute to the European Green Deal objective, the Commission is reviewing EU laws and has developed the Fit for 55 set of proposals to revise and update EU legislation to ensure that the EU reaches its intermediate targets for 2030. The proposals include:

- revision of the EU Emissions Trading System ("EU ETS");[13]
- creation of the Carbon Border Adjustment Mechanism ("CBAM");[14]
- revision of the land use, land-use change and forestry regulation ("LULUCF");[15]
- revision of carbon dioxide ("CO_2") emission standards for cars and vans;[16]
- methane emission reductions in the energy sector;[17]
- promotion of sustainable air fuel ("REFuelEU");[18]
- promotion of greener fuels in shipping (FuelEU Maritime);[19]
- deployment of alternative fuels infrastructure;[20]
- revision of the Renewable Energy Directive ("RED III");[21]
- revision of Energy Efficiency Directive ("EED");[22]
- promotion of energy performance of buildings;[23]
- promotion of the transition of the gas sector towards renewable and low-carbon gases;[24]
- revision of the Energy Taxation Directive (ETD);[25] and
- creation of a social climate fund ("SCF").[26]

Formal adoption of the first set of Fit for 55 regulations

The first set of Fit for 55 regulations was formally adopted by the Council on 28 March 2023. It includes, among other things, the revision of CO_2 emission standards for cars and vans[27] and the revision of LULUCF.[28]

The revision of CO_2 emission standards for cars and vans sets a target of 55% CO_2 emission reductions for new cars and 50% for new vans by 2030 compared to 2021. By 2035 new cars and vans must be emission free. However, it contains an exception for internal combustion vehicles, provided that these are operated with sustainable fuel.[28]

The revised LULUCF sets an objective of 310MtCO_2 equivalent of net removals in 2030.

Formal adoption of the second set of Fit for 55 regulations

The Council formally adopted a second set of Fit for 55 regulations on 25 April 2023.

The EU ETS, a carbon market based on a system of cap-and-trade of emissions allowances for energy intensive industries, the power generation sector and the aviation sector, was revised (i) to limit the exceptions for certain sectors and products, (ii) to increase the yearly emission reduction goals and (iii) to gradually include emissions from shipping for the first time.[29]

The Council agreed that free emissions allowances under the EU ETS for the aviation sector will be gradually phased out by 2026.[30] The Council also adopted the CBAM aiming to prevent the GHG emissions reduction efforts of the EU being offset by increasing emissions outside the EU through relocation of production.[31]

The Council has also formally adopted the SCF. Under the SCF, €86.7 billion of funding is made available to assist most vulnerable Europeans. EU countries can use the funding to finance measures and investments to support vulnerable households, micro-enterprises and transport users, helping them to cope with the price impacts of the EU ETS. This fund will in turn mainly be funded by revenues of the EU ETS, which amounts to €65 billion over the 2026-2032 period.[32]

Provisional political agreements for Fit for 55 regulations

In the context of the Fit for 55 package, the Council and the Parliament have reached several provisional political agreements:

- On 19 December 2022, the Council reached an agreement on the Commission's proposal to track and reduce methane emissions in the energy sector. The agreement introduces new requirements for the oil, gas and coal sectors to measure, report, verify and minimise methane emissions.[33]
- The provisional agreement on a revision of the EED of 10 March 2023 foresees an 11.7% reduction in final energy consumption at EU level in 2030, compared to the 2030 projects from 2020.[34]
- On 30 March 2023, the Council and the Parliament agreed provisionally on a revision of the renewable energy directive (ie RED III), which will increase the target for the share of renewables as foreseen under the REPowerEU strategy.[35]
- Regarding the implementation of a new regulation for the expansion of the alternative fuel infrastructure, a provisional agreement was reached on 28 March 2023. The agreement sets minimum capacity requirements for the alternative fuel infrastructure, including the electric recharging network.[36]

- The Council and Parliament reached an agreement on ReFuelEU Aviation on 25 April 2023, increasing the minimum quotas of sustainable air fuel gradually from 2030.[37]

The reaching of political agreement between the Council and the Parliament is the last step before formal adoption of the Fit for 55 proposals by the Council.

Revision of the EU Electricity Market Design

The European Commission also presented a proposal to revise the EU Electricity Market Design on 14 March 2023.[38] The European Commission identified shortcomings of the current market design, most importantly volatile electricity prices which place an economic burden on final consumers. The proposal therefore aims to better shield households and businesses from high energy prices, to increase resilience and to accelerate the transition envisaged in the European Green Deal and REPowerEU.

To protect consumers from volatile prices, the proposal provides for the right to fixed price contracts as well as dynamic price contracts and the right to multiple contracts. Consumers are offered a variety of contracts that best fit their circumstances. In addition, the proposal provides for households and SMEs to have access to regulated retail prices in the event of a crisis. Suppliers would be required to guard consumers against high price spikes by making greater use of forward contracts. A right to share renewable energy directly – eg, with a neighbour - shall also provide greater access to affordable renewable energy.

To enhance predictability of energy prices for the industry sector, the European Commission proposes to facilitate the deployment of more stable long-term contracts such as Power Purchase Agreements, which are currently mostly available only to large energy consumers in very few member states. By facilitation of these contracts, the European Commission also aims to give renewable energy supplies reliable revenues.

In June 2023, the Council adopted its position in relation to the Commission's proposal.[39] This general approach will now serve as a mandate for negotiations with the European Parliament on the final shape of the legislation.

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Overview of the legal and regulatory framework in the European Union

A. Historical overview

Until the mid-1990s, the energy market was highly fragmented. To increase energy security and competition, the EU worked toward an Energy Union. On its way towards an Energy Union, the EU implemented several legislative packages. Initially, this legislation focused on creating (cross-border) fair access, increased interconnection and regulation. Thus, the First Energy Package (the "FEP") introduced the first EU liberalisation directives for electricity and gas. The Second Energy Package (the "SEP") required EU Member States ("Member States") to establish national regulatory authorities. The Third Energy Package (the "TEP") aimed to create a single EU electricity and gas market.

Later, the focus shifted to the transition to renewable energy. Thus, the Clean Energy Package (the "CEP") was introduced. Its main objective was to re-design the electricity market and strengthen the role of the Agency for the Cooperation of Energy Regulators ("ACER"). The latest developments in particular the Fit for 55 package aim to meet the GHG reduction targets the EU has set itself for 2030 and 2050 under the European Climate Law.

B. Market governance

The European energy market is liberalised. As such, certain principles such as third party access and unbundling are enshrined as overarching governing principles in EU energy law.

B.1 Third-party access

Third-party access is one main pillar in the EU energy market governance. It serves the purpose of competition. The gas and electricity grids constitute natural monopolies, as it is unfeasible to build and operate several parallel electricity and gas grids. To ensure that the electricity and gas markets are open for competition, access must be secured for competitors.

Operators of transmission systems, storage facilities and in the case of gas, LNG facilities must:

- offer non-discriminatory services to all network uses;
- provide firm and interruptible third-party access services;
- offer both long and short-term services; and
- make services and tariffs transparent.[1]

In certain circumstances, major new infrastructure may be exempt from the third-party access rules. Exemptions for gas operators can be made if all of the following criteria are met:

- the investment must improve security of supply and boost competition in the gas market;
- the investment could not go ahead without the exemption due to the level of risk;
- the infrastructure must be owned by a legally separate entity from the TSO in whose system it will operate;
- users of the infrastructure must pay for access; and
- the exemption does not harm the functioning of the EU's internal gas market or the transmission system to which the infrastructure is linked.[2]

Exemptions for operators of new interconnectors may be granted under the same criteria. Additionally, it is necessary that the investment for the project cannot be made from capital gained through income from transmission systems to which it will be linked.[3]

B.2 Unbundling[4]

In the context of the EU market design, unbundling means the separation of the operation of gas pipelines and electricity networks at transmission level from the business of producing or supplying either electricity or gas.[5]

There are three unbundling models set out under the TEP:

- full ownership unbundling ("FOU");
- ISO; and
- independent transmission operator ("ITO").

Article 43(8) of the Electricity Directive and Article 9(9) Third Gas Directive contain details of a further unbundling model that is not entirely congruent with the above models but is however deemed to be as efficient.

FOU model

The FOU model requires the full separation of the operation of electricity and gas transportation or transmission networks and those activities related to production, generation and supply.[6] The model also puts in place restrictions in respect of ownership. The operators of electricity and gas transmission networks are no longer permitted to be part of (or affiliated to) a corporate group that is also active in supply or generation. The operator of the network must also own and control the entire network. In principle, the same rules apply to operators of electricity systems with regards to the ownership of recharging points for electric vehicles.[7] However, the criteria for derogations are more generous.

The FOU model does not prevent, in certain circumstances, a person or a company from holding shares in both a network operator and an entity involved in generation or supply activities provided that the shares constitute a non-controlling minority interest. Such interest must not carry any voting rights or other rights of veto in the entities concerned and must not have rights to appoint members of either of the entities' boards of directors. In particular, no person may be a member of the board of directors of the network operator and of a supply or generation undertaking; this may be particularly relevant to non-sector investors (eg pension funds).

ISO model

Under the ISO model,[8] the network must be managed by an identified independent system operator ("ISO") (which must perform all the functions of a network operator) although it is permitted for vertically integrated undertakings ("VIUs") to maintain ownership of their network assets.[9] The ISO model requires the ISO to comply with the same unbundling requirements as other network operators and for it to be a completely separate undertaking from the VIU.[10] On this basis, the ISO cannot have a shareholding in any supply or generation entities.

The TEP and the CEP also set out several regulatory provisions to reinforce the ISO model. A network owner active in supply or supply and generation must legally and functionally unbundle[11] the part of the company with ownership of the network and must finance[12] any investment decisions made by the ISO. The Commission (with assistance from ACER) approves[13] the identity of the ISO and, once the ISO has been appointed, it must commit to a ten-year network investment plan[14] arranged by the regulatory authority.

ITO model

The third model, the ITO[15], was introduced as a compromise after eight Member States noted that the FOU and ISO models were incompatible with their national regulatory regimes. The ITO model can be best described as a 'status-quo-plus' model as it permits some Member States such as France, Austria and Germany to keep in place their current structures where the TSOs belong to a VIU.

Under the ITO model, such undertakings must comply with additional regulations to ensure the independence of each such activity, which include:

- preventing the TSO's management from having particular positions of responsibility, interests or business relationships, directly or indirectly, with the relevant VIU.[16] This rule should be applicable to the majority of the TSO management for three years prior to their appointment[17];
- placing a minimum period of six months prior to the appointment of a person to the remainder of the management team of the TSO during which that person may not hold any management position or exercise any other relevant activity in the VIU.[18] The rules are intended to encourage the relevant national regulator to vet the executive management;
- examining network development and investment decisions taken by an ITO to ensure they are consistent with relevant Community wide plans[19];
- working against discriminatory behaviour by the ITO (and on the influence exerted by the relevant VIU), and restricting the ITO's access to the capital market, to be overseen by a supervisory body[20]; and

- enforcing compliance with the ITO provisions.[21] Penalties, depending on the breach, are defined in respect of the turnover of the ITO or of its relevant parent company.[22] The ultimate penalty for a persistently non-compliant ITO model is the mandatory introduction and designation of an ISO.[23]

To date, the ITO model appears to function well in practice; however, the Commission has suggested that it may be further improved. Examples of such improvements include strengthening the independence of the Supervisory Board, specifying the scope of the Compliance Programmes and developing common guidance and a network of cooperation for Compliance Officers, as well as harmonising the time frame for network development plans at national and European level. The Commission will therefore continue to monitor the implementation and effectiveness of the unbundling requirements under the revised Electricity Directive and the Third Gas Directive and continue to ensure that ITOs and VIUs comply with EU competition rules.

The ITO model only applies[24] in the Member States where TSOs continue to be part of a VIU. Member States that already implemented the ISO or FOU model are not permitted to revert to an ITO model. As a result, the ITO model continues to be the minimum level that is required to constitute effective network unbundling across the EU.

B.3 Third-country certification

NRAs must certify a TSO as compliant with the unbundling regime before the relevant TSO can take up its functions.[25] In addition, under the third country clause, NRAs must refuse certification of a TSO if the relevant company does not comply with the unbundling requirements, and its market entry would jeopardise the Member State's or the EU's security of supply.[26]

NRAs must also notify the Commission if:

- a transmission system owner or operator that is controlled by a party from a non-EU country applies for certification; or
- any circumstances arise that would result in a party from a non-EU country obtaining control of a transmission system owner or operator.[27]

TSOs (rather than the transmission system owners) must notify the relevant NRA if any circumstances[28] arise that would result in an entity from a non-EU country acquiring control of the transmission system or its operator. The relevant NRA must also seek the view of the Commission as to whether the foreign entity passes the unbundling and energy security tests and take 'utmost account' of the Commission's view.[29]

B.4 Regulatory oversight

Under the SEP,[30] Member States were required to establish NRAs; the NRAs that were established across the EU under this requirement had different powers and levels of independence in each Member State.

NRAs must be legally distinct and functionally independent from any other public or private entity.[31] The staff of the NRA and any member of its decision-making body are not permitted to seek or take instructions from any government or other public or private entity and must act independently of any market interest. For that purpose, NRAs must have an independent legal personality, autonomy over their budget, sufficient human resources and independent management.

The TEP and the CEP strengthen the NRAs' powers of market regulation and set out additional tasks for the NRAs, including:[32]

- ensuring the compliance of TSOs and DSOs with any third-party access regime, unbundling obligations, balancing mechanisms, congestion and interconnection management;
- reviewing TSOs' investment plans, and providing in its annual report an assessment of how far the TSOs' investment plans are consistent with the European-wide ten-year network development plan;
- monitoring network security and reliability and reviewing network security and reliability rules;
- monitoring transparency obligations;
- monitoring the level of market opening and competition and promoting effective competition in cooperation with competition authorities; and
- ensuring effective consumer protection measures.

The TEP and the CEP set objectives for the NRAs with a notable European dimension. The Third Gas Directive and revised Electricity Directive state that the NRAs' objective is to 'promot[e], in close cooperation with the Agency, regulatory authorities of other Member States and the Commission, a competitive, secure and environmentally sustainable internal market in natural gas within the Community, and effective market opening for all customers and suppliers in the Community, and ensuring appropriate conditions for the effective and reliable operation of gas networks, taking into account long-term objectives'.[33]

B.5 Market coupling

Market coupling aims to form an interconnected European electricity market optimising the allocation of cross-border capacities between European countries. The Regulation on Market Coupling,[34] which made market coupling for electricity trading legally binding across the EU, works in tandem with the ENCs designed to integrate electricity and gas systems across the EU.[35] Each Member State must designate an entity to be the Nominated Electricity Market Operator ("NEMO"). The NEMO performs tasks related to the single day-ahead or single intraday market coupling.

C. Network regulation

C.1 Network cooperation

The increasing energy demand and simultaneous import dependency of the EU requires improved transmission networks that can cope with the energy traffic created by the export and import of electricity and gas in peak demand conditions.

Cooperation in grid operation is therefore indispensable, especially in the electricity sector, where cooperation between TSOs make an important contribution to network reliability particularly in heavily interconnected areas. Greater transparency and visibility of network development issues allows investments to be made where they are most effective and improve network reliability through coordinated investments.

The Electricity and Gas Regulations formalise cooperation between transmission network operators, which are channelled through platforms such as Gas Transmission Europe ("GTE") and the European Technical Standard Order ("ETSO"), through the European Network of Transmission

System Operators for electricity and gas ("ENTSO-E" (electricity) and "ENTSOG" (gas)).

The responsibilities of ENTSOS include the following core areas:

- development of coherent market and technical codes needed for the integration of the electricity and gas markets, which the ENTSOs are tasked to develop in cooperation with ACER and the Commission on the basis of the framework guidelines developed by ACER;
- development of common network operation tools to ensure coordination of network operation in normal and emergency conditions, including a common incident classification scale, and research plans;
- finance and management of cooperative research and innovation activities focused on the technical development of European electricity and gas networks in relation to energy security, efficiency and low carbon technologies;
- coordination of grid operation, ie to exchange network operational information and the coordinated publication of information on network access; and
- coordination of the planning of network investments and monitoring the development of the transmission network capacities. The two ENTSOs must publish a European-wide and ten-year forward-looking investment plan every two years.

The overall effect of the increased cooperation of TSOs in the framework of the strengthened ENTSOs is undoubtedly a greater degree of market harmonisation, which in turn may result in better network and operational reliability and, as such, in better security of supply.

C.2 Regulatory framework

Network codes and guidelines

The EU is taking strides towards a functional Internal Energy Market ("IEM") through the creation of binding Network Codes ("NCs") or guidelines that provide harmonised rules for the operation of the electricity and gas sector in Europe. Under the TEP and the CEP, these rules effectively govern cross-border electricity and gas market transactions, allowing for better management of energy flows given the increase in interconnections and trade between countries in the IEM.[36] In effect, NCs and guidelines have been drafted to align wholesale market and network access arrangements in Member States, facilitating the emergence of a competitive European market in electricity and gas.

The Commission is responsible for defining an annual (triennial for electricity network codes) priority list for the development of ENCs through a consultation process set out in Article 59 of the revised Electricity Regulation and Article 6(1) of the Gas Regulation. When the priority list is defined, ACER[37] develops non-binding framework guidelines that set principles for developing specific NCs under Article 59 of the revised Electricity Regulation and Article 6 of the Gas Regulations.

The ENTSOs are tasked with preparing the ENCs under Article 30 of the revised Electricity Regulation and Article 8 of the Gas Regulation. The ENTSO-E and ENTSOG draft the codes based on ACER's framework guidelines. If ACER finds that the produced codes meet the framework guidelines and the EU's internal market objectives, the Commission is recommended to undergo the process of comitology (ie a set of procedures through which EU countries control how the Commission implements EU law). A Cross-Border Committee (consisting of specialists from national energy ministries of Member States) considers the draft codes. When accepted by the committee, the codes are adopted with the approval of the Council and the European Parliament.

The framework guidelines and NCs are highly detailed and technical. The benefits of such coherent European codes are generally to be found in the intended elimination of inconsistencies at national level regarding, eg tariff structures, capacity allocation rules, balancing arrangements and trading timetables, and security of supply measures.

Differences in market design lead to market segmentation, with some national markets remaining split into different local tariff or balancing areas. However, at the same time, the development of the ENCs will necessarily cause some friction to the existing, national approaches and is likely to be a long-term project the results of which is cumulative and not available for some time.

The network codes ("NCs") have been enacted in the form of regulations, making them directly applicable and binding in their entirety on Member States. Accordingly, they take precedence over national provisions. However, if national legislation, standards and regulations are compatible with the provisions of the ENCs, they will retain their applicability provided that they consist of more stringent requirements and standards than the ENCs. The Commission may adopt new rules in the form of guidelines rather than codes, which are adopted under a different provision of the Electricity Regulation; however, the adopted guidelines have the same status as the codes and are legally binding regulations.

Electricity

In the electricity sector, the NCs fall into three key interrelated areas, ie market codes, grid connection codes, operational codes and cybersecurity codes, and include the following:

- Capacity allocation and congestion management code ("NC CACM"). The NC CACM was established under Regulation (EU) 2015/1222 ("Regulation on Market Coupling"), which made market coupling legally binding across the EU. The NC CACM effectively puts in place the legislative framework necessary for the market coupling process across the EU and establishes the process by which bids and offers from national power exchanges for cross-border trading are brought together and matched in an optimal manner across borders. The Common Grid Model Methodology, and the Generation and Load Data Provision Methodology sets out the information and processes necessary to create a Common Grid Model representing the European interconnected system for the purposes of single day-ahead and intraday coupling methodologies under the NC CACM.[38] The NC CACM is in line with the recast Electricity Regulation.
- Forward capacity allocation code ("NC FCA"). The NC FCA establishes common rules for forward capacity allocation over a long-term time frame, including the establishment of a common methodology for determining the volumes of capacity simultaneously available between bidding zones. The principal objective of the NC FCA is to facilitate the development of liquid and competitive forward markets in a coordinated manner across Europe. Putting in place harmonised cross-border forward markets enables parties to secure capacity and hedge positions ahead of the day-ahead

time frame more efficiently in the IEM. The NC FCA is in line with the revised Electricity Regulation.

- Electricity balancing code ("NC EB"). The NC EB is intended to harmonise balancing markets, ensuring a clear time separation between intraday trading and balancing by TSOs, and the standardisation of balancing products across Europe. This includes rules for balancing energy pricing and imbalance pricing. Together, these rules aim to increase opportunities for cross-border trading, in turn facilitating the efficiency of balancing markets. The NC EB is in line with the recast Electricity Regulation.
- Requirements for Generators code ("NC RfG"). The NC RfG seeks to set common requirements for generators across the EU, detailing rules for grid connection of power-generating facilities, principally on new power-generating installations to national electricity networks. With more power being generated from embedded renewable technologies there is a need for network operators at transmission and distribution system levels to introduce this NC to ensure security of a stable supply. In addition to general requirements, the NC RfG details specific requirements for Synchronous Power-Generating Modules, Power Park Modules and AC connected Offshore Power Park Modules to the interconnected system.
- Demand connection code ("NC DCC"). The NC DCC establishes requirements for new demand users and distribution connections to the network. In doing so, it sets out rules for grid connection for four categories of entities including transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems (including closed distribution systems) and demand units that provide demand response services to relevant operators and TSOs. It aims to facilitate increased competition in the internal electricity market and increase security and the integration of renewable electricity. The key objective is to ensure system operators use demand facilities and distribution systems capabilities in a transparent, non-discriminatory manner so as to provide a level playing field throughout the Energy Union. The NC DCC mainly focuses on the connection of industrial loads and distribution networks.
- High-voltage-direct-current connections code ("NC HVDC"). The NC HVDC specifies requirements for long distance direct current connections and links between different synchronous areas and DC-connected Power Park Modules, such as offshore wind farms, which are becoming increasingly prominent in the European electricity system.
- System operation code ("NC SO"). The NC SO sets out common requirements for the maintenance of the secure operation of the interconnected transmission system in real time. In doing so, it establishes harmonised rules for ensuring the operational security of the IEM and sets requirements, ranging from the year-ahead time frame to real time, for assessing the adequacy of the interconnected power system. The NC SO details rules for planning outages required by TSOs when they have cross-border impacts on power flows. The NC SO is in line with the revised Electricity Regulation.
- Emergency and restoration code ("NC ER"). The NC ER provides a set of common minimum requirements including remedial procedures and principles to coordinate system operation across Europe in emergency, blackout and restoration states. The principal objective of the code is to avoid widespread disturbances and prevent the deterioration of an incident, ensuring efficient restoration from states of emergency and blackouts. It therefore involves advanced plans for system restoration, re-synchronisation, and information exchange, as well as the ad-hoc analysis of the incidents.
- Cybersecurity code ("NC CS"). On 14 July 2022, ACER has submitted to the European Commission its revision of a draft network code on cybersecurity. It includes rules on various electricity cybersecurity related aspects, including (i) a common electricity cybersecurity framework aimed to standardise the measures in place to protect the EU electricity cyber perimeter, (ii) governance of cybersecurity for the electricity sector, (iii) a comprehensive cross-border risk management process, (iv) cybersecurity information sharing flows to ensure timely information and foster quick and coordinated reaction of relevant stakeholder, (v) rules on incident handling and crises management, (vi) a cybersecurity exercise framework to enhance preparedness of all operators, (vii) rules for the protection of information exchange and (viii) a framework for monitoring, benchmarking and reporting. Currently, the Commission is reviewing the draft.

Gas

In the gas sector, the network codes include the following:

- Capacity allocation mechanisms in gas transmission systems code ("NC CAM"). The NC CAM aims to ensure more efficient allocation of capacity on the interconnection points between two or more Member States or within the same Member State and to support the creation of efficient wholesale gas markets in the EU. The code requires gas grid operators to use harmonised auctions when selling access to pipelines. These auctions sell the same product at the same time and according to the same rules across the EU.[39] The NC CAM sets out how adjacent TSOs should cooperate to facilitate capacity sales, having regard to the general commercial and technical rules related to capacity allocation mechanisms.
- Interoperability and data exchange rules code ("NC IDER"). The NC IDER aims to facilitate EU-wide cross-border gas transports by introducing common rules and harmonised principles on the establishment and amendment of interconnection agreements for interconnection points. In this way, the NC IDER aims to remove perceived barriers to cross-border gas flows and facilitate EU-wide market integration. The code outlines a common set of units that must be used by TSOs for any data exchange and publication. It also aims to regulate the monitoring and management of gas quality that may give rise to trade restrictions. Other key areas covered by the code include odorisation, common data exchange solutions and rules for dispute settlement mechanisms in interconnection agreements.
- Gas balancing of transmission networks code ("NC GBTN"). The NC GBTN introduces a market-based and harmonised daily balancing regime for Europe's transmission networks, facilitating gas trade across balancing zones. The NC GBTN contributes towards the development of market liquidity, supporting the development of Europe's competitive short-term wholesale gas market with gas flexibility that enables network users to efficiently balance their balance portfolios.
- Harmonised transmission tariff structures for gas code ("NC TAR"). The NC TAR applies at all entry and exit points of gas transmission networks and establishes rules on the

application of a reference price methodology, the associated consultation and publication requirements as well as the calculation of reserve prices for standard capacity products.

Transparency and record keeping obligations

The revised Electricity Directive and Third Gas Directives set out a number of record keeping obligations on electricity generators, gas network operators, and supply undertakings that are required to keep a record of all data relating to operational decisions and trades.[40]

The Commission hopes that these obligations enable regulators to effectively assess allegations of market abuse and study past behaviour of market participants. In particular, the Commission believes that a review of the relevant records enables regulators to investigate whether operational decisions are based on sound economic reasoning rather than attempts to manipulate the market.

The Commission has stated that these record keeping obligations are, in the case of some types of traders (eg banks), not in addition to relevant record keeping obligations of such traders under financial services legislation (see section J).

Congestion management procedures

The Commission's rules on Congestion Management Procedures ("CMPs") aim to reduce congestion in gas pipelines by requiring TSOs to make use of their reserved capacity or risk losing it. As such, NRAs require TSOs to partially or fully withdraw systematically underutilised contracted capacity on an interconnection point ("IP") where the network user has not sold or offered under reasonable conditions its unused capacity and where other network users request firm capacity.

Contractual congestion, ie when the demand for firm entry or exit capacity services exceeds the offered capacity, was identified at 18 IP sides (out of 200), down from 19 in 2020 and 37 in 2019[41], of which three were congested for the first time.[42]

ACER, in its recommendation to NRAs, ENTSOG and TSOs (December 2022), recommends that CMP data availability needs to be further improved by ENTSOG/TSOs, by ensuring that auction results with premia and data on all non-available capacity products are uploaded as required by the CMP Guidelines. ACER's recommendations to the Commission included revising the CMP Guidelines to enhance the effectiveness of the measures and reviewing certain criterion of the CMP Guidelines to align it with other congestion criteria.

D. Energy infrastructure

Energy security involves ensuring consumers are provided with an uninterrupted affordable supply of energy. To this end, the Energy Union Strategy focuses on mutually reinforcing and closely interrelated strategies involving energy security, a fully integrated energy market (ie IEM), energy efficiency, climate action and research and innovation.

Under the Energy Union Strategy, the Commission pledged to work with Member States regarding security of energy supplies and development of access to alternative suppliers, including from the Southern Corridor route, the Mediterranean and North Africa countries, which would decrease dependency on individual suppliers. The strategy also focuses on exploring the full potential of, in addition to renewable energy, the supply of liquefied natural gas ("LNG"), including as a backup in cases of insufficient gas supplies from Europe.

These strategies are designed to bring greater energy security, sustainability and competitiveness to the Energy Union, built on the cornerstone of a robust energy infrastructure.

D.1 Development

Guidelines for the development and interoperability of priority corridors and energy infrastructure at European level are set out in the regulation on trans-European energy networks ("TEN-E Regulation").[43] Under the regulation, strategic regional groups shall be established based on a priority corridor and geographical area for energy infrastructure with a trans-European or cross-border dimension, and the process for selecting Projects of Common Interest ("PCIs") is set out.[44] These infrastructure projects, PCIs, are considered essential to achieving Europe's aim of achieving energy security. PCIs also contribute to the development of energy infrastructure networks in each of the corridors.[45] The PCIs are adopted by the decision-making body of each regional group consisting of the Commission and Member States.[46]

PCIs are subject to different, improved, regulatory treatment as well as faster and more efficient permitting procedures. The projects can also receive funding under the Connecting Europe Facility ("CEF")[47] and EU financial assistance.[48] The regulation puts in place process requirements for granting PCI permits, which include:

- giving priority status to PCIs;[49]
- time limits for the permit process;[50]
- a 'one-stop-shop' permit;[51]
- a single coordinating authority;[52] and
- a requirement that Member States assess the potential for streamlining permitting procedures.[53]

The list of PCI projects is updated every two years to integrate newly needed projects and remove obsolete ones; the current list[54] includes 98 energy infrastructure projects that are essential for the completion of the IEM and for reaching the EU's energy policy objectives of secure, sustainable and affordable energy. These PCIs are intended to help deliver the EU's climate objectives, furthering EU-wide integration by diversifying energy sources and transport routes. The 98 projects comprise of 67 electricity transmission and storage, five smart grid deployment, 20 gas, and six cross-border CO_2 networks.

D.2 Interconnection

Interconnectors are pipelines (gas or hydrocarbons) or high-voltage cables that connect different national energy markets. They contribute significantly to the security and continuity of the energy supply within the interconnected markets. With the increased production capacities from renewable energies interconnectors become even more relevant, as production of renewable energy is particularly fluctuating and often exceeds demand in certain places and is needed in others at the same time.

The regulatory framework strategy of the EU recognises the importance of interconnectors allowing energy to flow freely across the EU. The minimum interconnection for electricity is set at 15% of installed electricity generation capacity of

Member States by 2030.[55] The EU must double its current interconnection capacity over the next ten to fifteen years to deliver on its energy targets and the climate neutrality objectives.[56] This is being addressed by the TEN-E Regulation and the PCI scheme. They provide access to CEF finance for the development of infrastructure projects essential to better connect energy markets. Access to finance is also provided by the European Investment Bank ("EIB"), the European Structural and Investment Funds, and the European Fund for Strategic Investments.

D.3 Overhaul of energy system[57]

The energy system in Europe is built on parallel and vertical energy value chains, where specific energy sources are only linked to specific end uses. The Commission has concluded that this system is too linear and creates wasteful flows of energy, which it proposes to address by undertaking a complete overhaul of the energy system.

To further this goal, the Commission has issued its strategy for Energy System Integration based on system and sector integration, where sector integration means linking energy carriers (such as electricity, heat, cold, gas, solid and liquid fuels) with the various end-use sectors such as buildings, transport or industry. The Commission envisaged that interlinking sectors allows for the optimisation of the energy system as a whole, rather than decarbonising and making separate efficiency gains in each sector independently. This strategy involves various existing and emerging technologies, processes and business models, such as Information, Communications and Technology ("ICT") and digitalisation, smart grids and meters, and flexibility markets.

The energy system strategy has three main characteristics:

- a more efficient, and 'circular' system where waste energy is captured and re-used;
- a cleaner power system with more direct electrification of end-use sectors such as industry, heating of buildings and transport; and
- a cleaner fuel system for hard-to-electrify sectors such as heavy industry or transport.

This system is supported by better information for customers, digital energy services and support for research and innovation to create new synergies in the energy system.

On 18 October 2022, the Commission published the EU Digitalisation of Energy Action Plan which the Commission committed to in the Strategy for Energy System Integration. Key actions include:

- helping consumers increase control over their energy use and bills through new digital tools and services;
- controlling the energy consumption of the ICT sector through an environmental labelling scheme for data centres, an energy label for computers, measures to increase transparency on the energy consumption of telecommunication services and an energy efficiency label for blockchains; and
- strengthening the cybersecurity of energy networks through new legislation including a Network Code for cybersecurity aspects (see section C.1).

On 14 March 2023, the Commission proposed to reform the EU's electricity market design to boost renewables, better protect consumers and enhance industrial competitiveness.[58] The proposal foresees a revision to EU regulations and directives, including the Electricity Regulation, the Electricity Directive and the REMIT Regulation. The reform includes:

- wider choice of contracts and clearer information for consumers to have the option to secure long-term prices avoiding volatility;
- protection of vulnerable consumers;
- access for consumers to invest in regional renewable energy; and
- deployment of more stable long-term contracts such as Power Purchase Agreements for the industry.

E. Climate Change

E.1 European Green Deal

The European Green Deal ("EGD") sets out a strategy to achieve climate neutrality by 2050 and deliver on the EU's commitments as set out under the Paris Agreement. Comprising an array of ambitious measures to ensure Europe becomes the first climate neutral continent by 2050, the EGD is wide-reaching and traverses through all sectors of the economy, including energy, transportation, industry, employment, biodiversity and food.

The EGD's main elements cover eight key pillars:

- increasing the EU's climate ambition for 2030 and 2050;
- supplying clean, affordable and secure energy;
- building and renovating in an energy and resource efficient way;
- accelerating the shift to sustainable and smart mobility;
- mobilising industry for a clean and circular economy;
- fostering a zero-pollution ambition for a toxic-free environment;
- preserving and restoring ecosystems and biodiversity; and
- developing a fair, healthy, and environmentally friendly food system (from farm to fork).

Key deliverables

One of the key deliverables under the EGD is the European Climate Law, which creates a legally binding target of net zero greenhouse gas ("GHG") emissions by 2050 and provides a progress-tracking mechanism to ensure further action can be taken if needed.

Various initiatives of the eight key pillars have also been implemented, including:

- REPowerEU plan, aiming to supply Europe with secure, affordable and sustainable energy, with funding of €225 billion in loans and €20 billion in grants provided via the Recovery and Resilience Facility;
- EU Strategy on Adaptation to Climate Change, paving the way to prepare for the unavoidable impacts of climate change;
- EU Action Plan Towards Zero Pollution for Air, Water and Soil, which aims to reduce air pollution, sea litter and municipal waste, among other things, by 2030;
- 'Renovation Wave', which envisages the overhaul by 2050 of

220 million buildings to make the necessary contribution by the building sector to the 2050 net zero emissions goal;

- EU Code of Conduct on Responsible Food Business and Marketing Practice as part of the EU's 'farm to fork' strategy, which 65 companies and associations have signed; and
- a law to slow global deforestation and forest degradation driven by EU industry and consumption.

Financing the EGD

The EGD Investment Plan (also referred to as "Sustainable Europe Investment Plan") was introduced to the European Parliament, Council and Economic and Social Committee[59] with the aim of mobilising at least €1 trillion in sustainable investment to 2030. The plan has three main objectives: (i) increase funding for the climate transition and support sustainable investments, in particular the InvestEU Programme; (ii) create a framework enabling both private investors and the public sector to contribute to sustainable investments; and (iii) support public administrations to scope, structure and execute sustainable projects.

The €1 trillion investment comprises of:

- Just Transition Mechanism: €100 billion invested to financially support Member States facing challenges as a result of being more fossil-fuel dependent;
- InvestEU Fund: leverage around €372 billion of private and public investments in four sectors (sustainable infrastructure, research innovation and digitisation, SMEs, and social and investment skills), through an EU budget guarantee that will back the investments of partners, such as the EIB;
- Innovation and Modernisation Funds: around €48 billion in support of the EU transition to net zero to 2030 depending on the carbon price (support is partially funded through revenues arising out of auctioning of carbon allowances under the EU Emissions Trading System ("EU ETS")); and
- EU budget: €503 billion up to 2027 on climate and environmental spending.

Just transition mechanism

The Just Transition Mechanism is backed by three pillars of financing:

- Just Transition Fund: around €11.3 billion to support jobs and growth, with a further €32.8 billion under the EU Recovery Instrument (the amounts were significantly increased from original figures as part of the EU's post-pandemic green recovery plan);
- InvestEU: a scheme to mobilise investments of €45 billion (comprising of around €1.8 billion from the EU budget and additional private investments); and
- EIB: a public sector loan facility backed by the EU budget to mobilise between €25 billion and €30 billion of investments, with €1.5 billion from the EU budget and €10 billion provided by the EIB at its own risk.

E.2 EU Strategy on Adaptation to Climate Change

The Commission's EU Strategy on Adaptation to Climate Change refers both to various global agreements, including the Paris Agreement, the Sendai Framework for Disaster Risk Reduction and the Sustainable Development Agenda, and EU initiatives such as the Mission for a Climate Resilient Europe and the EU's sustainable finance agenda. Looking to reinforce the EU's capacity to adapt to climate change and become climate resilient by 2050, the new strategy aims to: (i) make adaptation to climate change smarter, swifter and more systemic; and (ii) accelerate international action in the field of climate adaptation.

To achieve these goals, the strategy sets out a number of actions among which are: (a) closing the knowledge gap on climate adaptation via the initiatives Horizon Europe, Digital Europe, Copernicus and EMODnet; (b) improving adaptation modelling, risk assessment and management tools; (c) exploring the best ways to collect uniform insured loss data and extending public access to environmental information under the INSPIRE Directive; and (d) developing and expanding the Climate-ADAPT platform, and establishing a European climate and health observatory.

The strategy aims to encourage regional and international cooperation, which would be improved by adopting a harmonised framework of standards and indicators. The strategy also seeks to facilitate the integration of climate change impact into Member States' reporting and fiscal frameworks by building mechanisms to measure the effect of risks associated with climate change on public finances and developing tools for climate stress testing. The strategy plans to help local adaptation and offer an adaptation support facility under the EU Covenant of Mayors (engaging and supporting cities and towns to commit to reaching the EU climate mitigation and adaptation targets). In addition, the actions under the strategy envisage proposing nature-based solutions for carbon removals, which would include: (a) accounting and certification for upcoming carbon farming initiatives; (b) further developing the EU taxonomy on sustainable activities; (c) developing an EU-wide climate risk assessment; and (d) promoting natural disaster insurance across Member States.

Additionally, the strategy aims to facilitate climate adaptation at the international level by assisting partner countries, particularly in Africa and the EU's Southern and Eastern neighbourhoods, candidate countries and potential candidates, to develop adaptation strategies, including through increasing the EU's financing for international climate adaptation.

E.3 European Climate Law

The European Climate Law[60] establishes a framework for 'the irreversible and gradual reduction' of GHG emissions caused by human activity.

A binding EU target of at least 55% reduction of net GHG emissions (emissions after deduction of removals) compared to 1990 levels is set for 2030[61] and a binding net zero target for 2050 at the latest.[62] In achieving the 2030 target, the Climate Law aims to give priority to predictable and swift emission reductions, while at the same time envisaging the increased removal of CO_2 by natural sinks.[63] In order to ensure that sufficient efforts are made to achieve the 2030 goal, the climate law limits the contribution of net removals within the 55% target to 225 million tonnes of CO_2 equivalent and makes provisions for adopting a 2040 target.[64] Under the Climate Law, the Commission must make a proposal for such a target within six months of the first global stocktake in line with Article 14 of the Paris Agreement, and may propose to revise this target within six months of the second global stocktake (expected to be in 2028 unless otherwise agreed).[65] In this context, the global stocktake refers to the review mechanism provided by the Paris Agreement of the collective progress towards achieving its purpose and long-term goals.

For the global stocktake under Article 14 of the Paris Agreement, the Commission must submit a report to the Council and the Parliament within six months of each global stocktake (expected to be every five years, unless otherwise agreed) on the operation of the regulation together with the conclusions of the assessments of EU progress, EU measures and national measures.

Alongside the original proposal, the Commission must publish a projected indicative EU GHG budget for the period 2030-2050.[66] This budget is defined as the total volume of net GHG emissions expected to be emitted without putting EU commitments under the Paris Agreement at risk. The climate law has an aspirational target for the EU to become carbon negative after 2050. The law commits the Commission to adopt a strategy on climate change adaptation in line with the Paris Agreement, as well as guidelines that provide common principles and practices for the identification, classification and management of material physical climate risks in planning, developing, executing and monitoring projects and programmes for projects.[67]

The law establishes the European Scientific Advisory Board on Climate Change,[68] which gives independent scientific advice and provides reports on existing and proposed EU measures, climate targets and indicative GHG budgets. Reports also outline their consistency with the climate law's objectives and the EU's international commitments under the Paris Agreement. The board also identifies actions and opportunities necessary to achieve the set targets. Member States are also encouraged to establish national climate advisory bodies to provide expert scientific advice to the relevant national authorities.[69]

The Commission also aims to involve and support all economic actors towards the achievement of the climate neutrality target and will engage with sectors of the economy that decide to prepare indicative voluntary roadmaps towards reaching the target. To help those sectors, the Commission monitors the development of such roadmaps, facilitate dialogue at EU-level and share best practices.[70]

By 30 September 2023 and every five years thereafter, the Commission will review the national measures identified as relevant for the achievement of the climate-neutrality target and will issue recommendations to the Member States, where it finds inconsistencies with the climate-neutrality objective or progress on adaptation. The recommendation must be made publicly available. Similarly, by 30 September 2023 and every five years thereafter, the Commission will assess Member States' collective progress on achieving net zero by 2050 and on climate change adaptation.[71]

E.4 Fit for 55

The adoption of the European Climate Law with its new emission targets requires adjustment of all existing legislation, which so far has been aligned with previously set targets. The Commission has therefore revised the relevant climate and energy legislation and proposed the Fit for 55 package, covering, among other things, renewables, energy efficiency, land use, energy taxation, CO_2 emission performance standards for light-duty vehicles, effort sharing and the EU ETS.[72]

Following from the Fit for 55 package, the Commission aims to align its draft measures and legislative proposals, including budgetary proposals, with the objectives of the climate law, assessing their consistency with the climate neutrality target and the 2030 and 2050 targets. The conclusions of this assessment are included in the impact assessment of the draft instruments. The Commission also considers whether the draft measures and legislative proposals are consistent with ensuring progress on climate adaptation.[73]

E.5 Energy generation

Renewable Energy Directives RED II and RED III

RED II

The European Union introduced the Renewable Energy Directive ("RED") in 2009, which sets binding EU-wide and member state-specific shares of renewable energy sources in energy consumption. The target was set at a 20% share in 2020. RED was revised in 2018 ("RED II"), setting the EU renewable energy target at 32% in 2030. RED II also includes a sub-target for the transport sector, requiring fuel suppliers to supply at least 14% of the energy consumed in road and rail transport from renewable energy by 2030.[74] It establishes sustainability and GHG emission criteria that liquid biofuels used in transportation must meet in order to count toward the renewable energy target and be eligible for financial assistance from public authorities.[75]

REPowerEU

The REPowerEU strategy is the result of the volatile developments on the energy market in the wake of Russia's invasion in Ukraine. It consists of several proposals of revisions to EU legislation and aims to reduce EU's dependency on Russian fossil fuels by:

- Saving energy;
- Diversifying supply; and
- Substituting fossil fuels with renewable energy sources.

RED III

In July 2021, the Commission proposed a revision of RED II as part of the CEP and the Fit for 55-package ("RED III"), raising the target to 40% in 2030. In view of Russia's invasion of Ukraine and now as under REPowerEU the Commission proposed a further increase to 45% in 2030. In March 2023, a provisional agreement was reached between the Council and the European Parliament setting a binding target of 42.5% but aiming for 45%.

In the transport sector, RED III sets a binding target of 14.5% reduction of GHG intensity and a binding share of 29% renewables within the final consumption by 2030. Within these targets for the transport sector, a binding sub-target of 5.5% is set for advanced biofuels (derived from non-food-based feedstocks) and renewable fuels of non-biological origin (mostly renewable hydrogen and hydrogen-based synthetic fuels).

The industry will be required to increase its use of renewable energy by 1.6% per year. 42% of hydrogen used in the industry must come from renewable fuels of non-biological origin by 2030 and 60% by 2035.

RED III will also introduce a target of 49% renewable energy in buildings in 2030, with annual targets increasing by 0.8% until 2026 and 1.1% from 2026 to 2030.

The agreement also provides for limited access to woody biomass by introducing a cascading principle and banned direct financial support for woody biomass.

The Council is expected to formally adopt RED III soon.[76]

EU Energy Platform

The EU Energy Platform was introduced in 2022 as part of the REPowerEU strategy. It aims at coordinating EU action and negotiations with external upstream suppliers of gas and hydrogen by preventing EU countries from outbidding each other. Based on this platform AggregateEU – a demand aggregation and joint purchasing mechanism – was introduced.[77] Under AggregateEU Member states are required to aggregate demand for volumes of gas equivalent to 15% of their respective storage filing obligations. Beyond this threshold, aggregation is voluntary. Services are provided by "Prisma European Capacity Platform GmbH". The mechanism aggregates gas demand from companies established in the EU or in Energy Community countries. It matches it with the most competitive supply offer.[78]

Funding

Phasing out Russian fossil fuel imports und REPowerEU is expected to cost €210 billion until 2027. To finance these efforts the Recovery and Resilience Facility ("RRF") – originally implemented to mitigate the economic and social impact of the coronavirus pandemic – was amended to integrate dedicated REPowerEU chapters.[79] Under the RRF, Member states can take out loans amounting to €225 billion. Additionally, grants amounting to €20 billion are provided by the Innovation Fund (60%) and the sale of Emission Trading System allowances (40%). Member states can also transfer up to €5.4 billion of funds from the Brexit Adjustment Reserve to the RRF.

E.6 Emission pricing

EU ETS

The core principle of the EU ETS is to promote reductions of GHG emissions in a cost-effective and economically efficient manner. The EU ETS requires operators of installations covered by the scheme to surrender emissions allowances, specifically EUAs (with each EUA reflecting 1 tonne of CO_2) in relation to each tonne of GHG emitted through their activities. Being a cap and trade system, the EU ETS fixes the annual total allowances allocated each year, therefore forcing operators to sell and purchase excess allowances as required. Following the second phase of the EU ETS, the cap of total emissions is decreasing by a set percentage to drive the reduction of carbon emissions.

The original EU ETS has been split into phases (phase IV started on 1 January 2021). The allowance reduction factors in the original EU ETS were not consistent with the GHG reduction targets set out in the European Climate Law. To meet the 2030 reduction target, a reduction of GHG emission covered by the EU ETS of 62% compared to 2005 is necessary.

Therefore, the EU ETS was revised as part of the Fit for 55 package.[80] It was formally adopted on 25 April 2023. Under the revision, the linear reduction factor, which sets out the reduction rate of the schemes emission cap, is increased to 4.3% per year from 2024 to 2027 and 4.4% from 2028 to 2030. In addition, the revision provides for a one-time reduction of the EU-wide quantity of allowances by 90 million in 2024 and by 27 million in 2026.[81]

Maritime

The revision also extended the scope of the EU ETS. For the first time, emissions from shipping are included.[82] Large ships with a gross tonnage of over 5,000 that load or unload cargo or passengers in EEA ports will be covered.[83] Specifically, the EU ETS is extended to cover emissions from these ships from intra-EU voyages, half of the emissions from extra-EU voyages, and all emissions occurring at berth in an EU port.[84] Under the Directive, shipping companies have to surrender 40% of their verified emissions as of 2024, 70% as of 2025 and 100% as of 2026.[85] Within this transition period, the sector will receive an annually declining percentage of free allocation. Other big vessels, namely offshore vessels, and non-CO_2 emissions will be included in the MRV regulation.

Aviation

The revision also ends free emission allowances for the aviation sector. The revised EU ETS applies to intra-European flights (including departing flights to the United Kingdom and Switzerland). For non-European flights, the Carbon Offset and Reduction Scheme for International Aviation ("CORSIA") will apply. The free emission allowances for intra-European flights will be gradually phased out until 2026.[86]

Buildings, road transport and additional sectors

The revised EU ETS includes a freestanding emissions trading system for buildings, road transport and additional sectors (mainly small industry not covered by the existing ETS).[87] The emissions allowance reductions will start in 2027.[88] The cap is intended to reduce emissions by 42% by 2030 compared to 2005 levels.

Market Stability Reserve

The Market Stability Reserve, which addresses the surplus of emission allowances, will continue to absorb 24% of the allowances in circulation each year beyond 2023 each year. From 2023, the absolute number of allowances in the Market Stability Reserve is limited to 400 million.[89]

Effort Sharing Regulation

The Effort Sharing Regulation was revised on 28 March 2023 as part of the Fit for 55 package.[90] Among other things, it sets out binding annual GHG emission targets for the period 2021-2030 for sectors that remain outside of the scope of the EU ETS, which includes national maritime transport, agriculture, certain buildings, non-ETS industry and waste. Combined, these sectors produce almost 60% of the EU's total domestic emissions and therefore must be accounted for in the EU's actions to achieve lower emissions. The sectors that fall under the scope of the Effort Sharing Regulation have to reduce their emissions by 40%. The regulation stipulates that Member States share the efforts to reach the EU-wide emission reduction targets and each Member State has a target set out on the basis of its gross domestic product, with the individual targets falling into a very wide range, from 10% to 50% compared to 2005 levels.[91] The regulation allows Member States to bank, borrow, buy and sell emissions in order to meet their target and also provides for the use of up to 262 million carbon credits for the land use sector over the period covered by the regulation (2021-2030).[92]

Carbon Border Adjustment Mechanism

The EU adopted the Carbon Border Adjustment Mechanism on 25 April 2023 as part of the 'Fit for 55'-package to address carbon leakage risks under the EU ETS ("CBAM Regulation").[93] The CBAM Regulation takes effect, subject to transitional provisions, from 1 October 2023.[94]

The CBAM Regulation complements the EU ETS and requires importers of certain goods (cement, electricity, fertilisers, iron, steel and aluminium, which are all on the EU carbon leakage list) to purchase a number of electronic certificates ("CBAM certificates"), reflective of the total embedded emissions in these imported goods. The price for CBAM certificates is benchmarked against the weekly average EU Allowance ("EUA") price.[95]

The obligation to purchase CBAM certificates and account for embedded emissions rests on importers, however, it is likely that the EU CBAM will impact international producers. Embedded emissions are defined as direct emissions released during the production of the goods, ie emissions from the production processes of goods over which the producer has direct control. Under the proposed CBAM Regulation, the amount of embedded emissions is to be based on the actual direct emissions of goods. If this cannot be determined, a default value is used.

The EU CBAM applies when in-scope goods are imported into the EU's customs territory from a third country (plus Iceland, Liechtenstein, Norway and Switzerland and certain territories).[96]

An importer may claim a reduction in the number of CBAM certificates to be surrendered, in order to take into account a carbon price paid in the country of origin.[97] The Commission is empowered to adopt implementing acts to establish the methodology for calculating the appropriate reduction, the conversion of a carbon price paid and the certification process for these.[98] The number of CBAM certificates to be surrendered may also be reduced in light of EU ETS allowances which would be freely allocated to EU producers of the same products.

Energy Taxation Directive

The Energy Taxation Directive ("ETD")[99] entered into force in 2003 and regulates minimum excise duty rates for the taxation of energy products used as motor fuel, heating fuel and electricity. These minimum rates are not consistent with GHG emission reduction targets under the European Climate Law, as they do not promote clean energy. Therefore, the Commission proposed a revision of the ETD on 14 July 2021.[100] It aligns the taxation of energy products and electricity with EU energy and climate policies and contributes to the EU 2030 energy targets and climate neutrality by 2050. These changes were introduced as part of the Commission's Fit for 55 package. The proposed changes include:

- A new structure of tax rates based on the energy content and environmental performance of fuels and electricity. Energy products and electricity are grouped in general categories per type and are ranked to ensure that the most polluting fuels are taxed at the highest levels.
- A broadening of the taxable base by including more products in the scope of the directive and removing some of the current exemptions and reductions for heavily polluting fuels such as kerosene and heavy oil. Over a period of ten years, the minimum tax rates for these heavily polluting fuels will gradually increase while sustainable fuels for these sectors will benefit from a minimum rate of zero to foster their uptake.

E.7 LULUCF

On 28 March 2023, the Council formally adopted a revision to the Land Use, Land-Use Change and Forestry regulation ("LULUCF regulation").[101] The LULUCF regulation was originally adopted in 2018. It covers the use of soils, trees, plants, biomass and timber, and is responsible for both emitting and absorbing CO_2 from the atmosphere. The revision introduces an EU-wide target for GHG emission removal of 310 million tonnes of CO_2 equivalent by 2030.[102] It also foresees an increase of the individual removal targets for each Member state.[103]

E.8 Emissions Standards Regulation

Passenger cars and vans ("light commercial vehicles") are responsible for around 14.5% of the EU's CO_2 emissions. The Emissions Standards Regulation ("ESR")[104] was introduced in 2019 setting CO_2 emission performance standards for new passenger cars and vans. On 28 March 2023, the Council formally adopted a revision of the ESR as part of the Fit for 55 package.[105]

The ESR establishes three target periods, ie 2020-2024, 2025-2029 and 2030 onwards.[106] The first period target levels refer to the New European Driving Cycle ("NEDC") emission test procedure and manufacturers' targets are determined on the basis of the new test procedure, the Worldwide Harmonised Light Vehicles Test procedure ("WLTP"), for measuring CO_2 emissions from, and fuel consumption of, passenger cars and light commercial vehicles. For the next two periods, ie 2024-2029 and 2030 onwards, stricter targets are applied, calculated as a percentage reduction of the 2021 targets. The revision sets new CO_2 emission reduction targets for the third period:

- 55% for new cars from 2030 to 2034 compared to 2021 levels;[107]
- 50% for new vans from 2030 to 2034 compared to 2021 levels;[108] and
- 100% for both new cars and vans from 2035.[109]

The revision includes a reference requiring the Commission to submit a proposal for registering vehicles exclusively running on CO_2-neutral fuels after 2035.

If a manufacturer's fleet of newly registered light commercial vehicles exceeds the annual emissions target, the manufacturer must pay a premium of €95 per gram CO_2/km.[110]

E.9 Methane Emissions Regulation

As the second biggest contributor to climate change after CO_2, methane is also a strong local air pollutant. Efforts to thwart its emissions are therefore key to achieving the 55% GHG emissions target.

Based on a proposal from the Commission in 2021 as part of the Fit for 55 package[111], the Council reached an agreement on a proposal to track and reduce methane emissions in the energy sector. According to this proposal, the oil, gas and coal sectors will be required to measure, report and verify methane emissions.

The proposal also envisages sector-specific measures, several of which are within the energy sector, such as proposing actions to improve the detection and repair of leaks in gas infrastructure, and considering legislation to prohibit routine flaring and venting practices.

E.10 Energy efficiency

Energy Efficiency Directives

To continue to cut emissions and tackle energy poverty, the Commission, the Council and the Parliament in March 2023 provisionally agreed terms to reform and strengthen the Energy Efficiency Directive ("EE Directive"), which was a step further towards the completion of the Fit for 55 package.[112] Under these provisional terms, EU countries are required to take energy efficiency into consideration in policy planning and major investment decisions in the energy sector and beyond.

The annual energy saving obligations for Member States should almost double under the proposed amendments to the EE Directive, and the public sector will be required to renovate 3% of its buildings each year to create jobs and bring down energy use and costs to the taxpayer. Other key amendments under the proposed revised EE Directive include:

- Alignment of efficiency targets: efficiency targets are adjusted and aligned with the new energy efficiency target for 2030. The EU targets are set in terms of the level of final and primary energy consumption to be achieved in 2030. National contributions remain indicative, but benchmarks and a new delivery mechanism are proposed.
- 'Energy efficiency first' principle: this new principle includes an obligation to consider energy efficiency solutions in policy and investment decisions in both energy and non-energy sectors, including social housing.
- Lower public energy consumption: the public sector must reduce its energy consumption for public services and installations of public bodies. Other subsectors affected by this obligation are transport, public buildings, spatial planning, and water and waste management.
- Renovation obligation: the scope of the renovation obligation is broadened, being applied to all public bodies and all administration levels in all public activities sectors (including healthcare, education and public housing). The alternatives that permitted Member States to reach similar energy savings through measures other than renovations have been removed.
- Global warming potential: contracting authorities may require that tenders disclose a Global Warming Potential of new buildings, in particular for new buildings over 2,000 square metres.
- Consumer protection: consumer protection is strengthened by introducing basic contractual rights for district heating, cooling and domestic hot water in line with the provisions set out under the recast Electricity Directive. In particular, Member States must establish the concept of vulnerable customers by also taking into account final users who have no direct or individual contract with energy suppliers.
- Certifications: new and different qualification, accreditation and certification schemes are set out for different energy services providers, energy auditors, energy managers and installers. Member States will be required to update these schemes every four years starting as of December 2024.
- Energy efficiency investments and reporting: Member States are required to report on energy efficiency investments (including on energy performance contracts executed) and to set out project development assistance mechanisms at national, regional and local levels to promote investments to help reaching the higher energy efficiency targets.

Energy Performance of Buildings Directive

Buildings are responsible for approximately 40% of EU energy consumption and 36% of the energy related greenhouse gas emissions. This makes buildings the single largest energy consumer in Europe. Almost 75% of the building stock is energy inefficient, yet only 1% of the building stock is renovated each year. Therefore, the building sector offers great potential for GHG emission reductions.

The Energy Performance of Buildings Directive ("EPBD") aims to unlock this potential.[113] As part of the 'Fit for 55'-package and the Renovation Wave Strategy, the Commission proposed a revision of the current EPBD in 2020.[114] On 25 October 2022, the Council reached an agreement on a general approach for the revision of the EPBD.[115] The main objectives of the agreement are:

- from 2028 all new buildings owned by public bodies are zero-emission buildings;
- from 2030 all new buildings are zero-emission buildings; and
- from 2050 all existing buildings are transformed into zero-emission buildings.

E.11 Sustainable fuel

ReFuelEU Aviation

Aviation emissions in Europe increased by an average of 5% per year from 2013 to 2019 before the pandemic. ReFuelEU Aviation, together with the incorporation of aviation into the EU ETS, aims to reverse this trend. The Council and the European Parliament reached a provisional political agreement on a proposal for the ReFuelEU Aviation Regulation on 25 April 2023.[116] Most notably, the regulation will require aviation fuel suppliers to supply a minimum share of sustainable air fuel at EU airports, starting at 2% of overall fuel supplied by 2025 and reaching 70% by 2050.

FuelEU Maritime

Ship traffic to or from ports in the European Economic Area accounts for around 11% of all EU CO_2 transport-related emissions and 3-4% of total CO_2 emissions in the EU. To increase demand for the use of renewable and low-carbon fuels in the maritime sector, the Commission proposed the FuelEU Regulation on 14 July 2021.[117] On 2 June 2022, the Council adopted its general approach to the proposal. It would apply to all ships above a gross tonnage of 5,000 and cover,

- 100% of the energy used within a port of a Member State;
- 100% of the energy used on intra-EU voyage;
- 50% of the energy used on voyages departing from or arriving to a port located in an outermost region under the jurisdiction of a Member State; and
- 50% of the energy used on extra-EU voyages.

Starting at 2% in 2025, the amount of GHG emissions by a ship must be reduced by 75% by 2030, compared to 2020 levels.

Alternative fuels infrastructure

Recharging is considered under the Alternative Fuels Infrastructure Directive ("AFID").[118] The Directive requires Member States to establish frameworks for provision of publicly available refuelling and recharging points and aims to improve coordination on the development of the necessary infrastructure in order to provide certainty for investors and thereby encourage investment. The Directive suggests that, where possible, recharging points make use of intelligent metering systems. To encourage wider deployment of such infrastructure, the Directive notes that operators of recharging points shall be able to purchase electricity from any electricity supplier in the EU, subject to the supplier's agreement. To further encourage the transition to alternative fuels and ease of adoption, it states that electric vehicles ("EVs") should be allowed to recharge on an ad-hoc basis without requiring a contract with the electricity supplier or operator. It also looks to guarantee that prices for recharging are reasonable, easily and clearly comparable, transparent and non-discriminatory. Moreover, the Directive seeks to ensure that Member States permit that the electricity supplier for the recharging point may be different of the supplier that provides electricity to the household or entity where the recharging point is located to offer competitive consumer choice and open market.

The Directive notes that the EU shall pursue the development of European standards in relation to specifications for wireless recharging points and battery swapping for motor vehicles, and for recharging points for L-category motor vehicles and electric buses.[119] It further requires Member States to provide information to users for motor vehicles that can be regularly fuelled with individual fuels placed on the market or recharged by recharging points.[120]

In March 2023, the Council and the European Parliament reached an agreement on repealing the AFID and replacing it with the Alternative Fuels Infrastructure Regulation ("AFIR").[121] The main targets of the AFIR are:

- For each registered battery-electric car in a given Member state, a power output of 1.3kW must be provided by publicly accessible recharging infrastructure from 2025 onwards.
- Every 60km along the trans-European transport ("TEN-T") network, fast recharging stations need to be deployed for light and heavy duty vehicles from 2025 onwards.
- Every 200km along the TEN-T core network and in all urban nodes, hydrogen refuelling infrastructure must be deployed from 2030 onwards.
- Larger ports must provide shoreside electricity by 2030.
- Airports must provide electricity to stationary aircraft at gates by 2025 and remote stands by 2030.

Low-carbon fuels

Hydrogen

The Commission has published the European Hydrogen Strategy and launched the industry led European Clean Hydrogen Alliance ("ECHA"). The Hydrogen Strategy sets out the Commission's vision for how the EU can harness the power of hydrogen to achieve its commitments to decarbonise the continent and transition to clean energy by 2050. In particular, it sees hydrogen being used as a (low carbon or renewable) fuel, a form of energy storage (to manage seasonal variations and intermittence in renewable energy production as well as to transport energy from production centres to more difficult to connect energy demand centres), and an alternative to fossil fuels in hard-to-abate carbon-intensive industrial processes (such as in the steel and chemicals industries).

The strategy is divided into three phases, covering the years 2020-2024, 2025-2030 and 2030-2050 respectively. The Commission aims to carry out the following priority actions in each phase:

- phase 1: install at least 6GW of green hydrogen electrolysers capacity in the EU and increase green hydrogen production within the EU to 1 million tonnes;
- phase 2: (i) install at least 40GW of green hydrogen electrolysers capacity within the EU and (ii) increase green hydrogen production within the EU to 10 million tonnes; and install and secure access to another 40GW of green hydrogen electrolysers capacity from neighbouring countries; and
- phase 3: green hydrogen technologies to reach their maturity and to be deployed at large scale including in all hard-to-abate sectors.

As part of the EU's industrial strategy, the ECHA was launched to support the implementation of the Hydrogen Strategy. The ECHA is designed to bring together EU institutions, national, regional and local governments, industry participants across the value chain as well as other industry and societal stakeholders (such as trade unions, NGOs and industry and technological bodies) in a round table policy making forum. It is envisaged that the ECHA will create a platform for the industry to coordinate and consult on projects that are needed to develop a clean hydrogen ecosystem as well as to assist in identifying the main (regulatory, technological, procedural and standardisation) bottlenecks and input into ongoing work on standardisation and research and development priorities.

The ECHA's governing body is made up of 12 industry representatives. Its work will span the entire hydrogen value chain and will be structured around six project sub-categories: hydrogen production; transmission distribution; energy sector; industrial applications; mobility; and residential applications. The ECHA has primarily been tasked with identifying and building up a pipeline of viable large-scale clean hydrogen investment projects. Some of these projects will qualify for Important Projects of Common European Interest ("IPCEI") status and/or will qualify for support from EU investment and funding initiatives. Where a project qualifies for IPCEI status, Member State governments will be allowed to offer funding to these projects beyond the usual amounts allowed under the EU rules on state aid limits.

Biofuel

RED II and the agreed RED III establish binding criteria to ensure that biofuel and bioliquid production are environmentally sustainable. For the purposes of meeting national targets, energy from these sources must fulfil the requisite criteria. The criteria relate to biodiversity, the protection of rare, threatened or endangered species and ecosystems, and GHG emissions savings.[122]

Any GHG emissions savings resulting from the use of biofuel produced in existing biofuel production plants have had to amount to at least 50% compared with the emissions from using fossil fuels, whereas GHG emissions from the use of biofuel produced in new installations (ie those installations which commence production after 1 January 2017) had to be at least 60% lower than those from fossil fuels. Unlike traditional, 'first-generation' biofuel, it is thought that second-generation biofuels do not present the same risks to the security of food supplies as these biofuels are, eg, produced from wastes, residues, or biomass such as algae, wood residues, or paper waste.

RED II limits the way Member States can meet the target of 10% for renewables in transport fuels with a cap of 7% on the contribution of biofuels produced from food crops.

The remaining 3% target for renewables in transport fuels may come from a range of alternatives, including:

- biofuels from used cooking oil and animal fats (counted double);
- renewable electricity in rail (counted two and a half times);
- renewable electricity in EVs (counted five times);
- advanced biofuels (counted double); and
- benchmark for the share of advanced biofuels in the transport sector of 0.5%.

In addressing indirect land use change ("ILUC") emissions, RED II regulates how the share of energy from renewable sources is calculated. This includes that the maximum share of biofuels and bioliquids from food or feed crops is to be decreased. Member States can also set a lower limit and can distinguish between different types of biofuels and bioliquids; eg, in considering ILUC, a lower limit may be set for biofuels produced from oil crops. Such measures are intended to stimulate decarbonisation and energy diversification and ensure cost-effective measures for the sector in contributing to the overall target achievement.

The EU sustainability criteria include biomass and biogas for heating and cooling, and generation of electricity. The criteria for agriculture biomass are simplified and a new risk-based criterion is introduced for forest biomass. The mass balance system is clarified and adapted to include biogas co-digestion and injection of biomethane in the natural gas grid (under the mass balance system, generators use an input equals output basis to account for their biomass fuel; however, they do not need to physically separate certified/uncertified biomass).

E.12 Other clean energy policies

Offshore renewable energy

The Commission's EU Strategy to harness the potential of offshore renewable energy for a climate neutral future[123] pledges to turn offshore renewable energy into a key part of the EU energy system by 2050. It sets ambitious expansion plans for offshore renewable energy capacity; it envisages increases in offshore wind generation to 300GW and ocean energy to 40GW by 2050, with intermediate targets of 40GW for offshore wind and 1GW for ocean energy by 2030. Taking into account that existing installed offshore wind capacity is 12GW, the set targets amount to an almost 30 times increase of offshore renewable energy capacity by 2050, which would require substantial uptake of renewable energy installations.

In order to achieve these targets, the Commission has set out a number of areas that would require policy and regulatory changes. In particular, sustainability, biodiversity and the protection of the environment will be considered in all aspects of the strategy. In terms of maritime spatial planning, the strategy envisages that Member States would have to identify and use a much larger number of sites for offshore renewable energy production than before in order to ensure sufficient territory for the development of installations. It also suggests that the current approach to national marine spatial plans may evolve over time into a coordinated sea basin strategies and plans, including into establishing regional sea conventions.

Hybrid projects

The strategy sets out plans to move from the existing model of radial links to the shore to the development of hybrid projects and, further down the line, to a more coordinated, meshed, grid. Hybrid projects may take various forms, including as energy islands and hubs. The key difference with radial links is that the new setup will benefit from dual functionality; it will combine electricity interconnection between Member States with transportation of offshore renewable energy. This approach could reduce costs and the use of maritime space but will require further cooperation and integration between Member States, transmission service operators and regulators.

Given that further integration of grid connections will be needed, the strategy plans to establish a clearer EU regulatory framework for offshore renewable energy, which could also involve set up of offshore bidding zones. The strategy notes that dedicated support for emerging offshore renewable energy technologies (tidal, wave and floating offshore wind) will continue to be needed and that a revenue stabilisation system may be helpful to ensure investor certainty.

In June 2022, the revised Regulation on Trans-European Energy Networks entered into force.[124] It implements these ambitions, by including infrastructure categories for hybrid offshore grids and radial lines, as well as permitting provisions to accelerate the scale-up of offshore grids.

Investment and R&I

Investment is essential to deliver the desired offshore renewable energy capacity and it is estimated that €800 billion will be needed, the majority of which is envisaged to come from private capital. EU programmes such as the new InvestEU programme and the Recovery and Resilience Facility could facilitate private investment. As funding under the latter programme needs to be committed by the end of 2023, Member States must offer a pipeline of mature projects with companies already prepared to invest, in order to benefit from the funding.

Moreover, the strategy offers space for research and innovation of renewable energy technologies and suggests that the first work programme for the Horizon Europe programme includes support for emerging offshore renewable energy technologies such as floating offshore wind, ocean wave and tidal energy, and development of innovative grid technologies.

As the strategy aims to strengthen the offshore renewable energy supply chain across the continent, the Commission proposes to establish a dedicated offshore renewable energy working group that facilitates sharing of knowledge and expertise between different parts of the supply chain. It also plans to provide education and training to build skilled workforce, develop a circular approach to decommissioning, wind turbine components reusing and recycling and employing international partnerships, more specifically with developing countries and emerging markets, to expand offshore renewable energy.

Waste to energy

The Waste Framework Directive[125] establishes targets for Member States, eg, the preparing for re-use and the recycling of municipal waste should increase to a minimum of 55% by weight by 2025 and to 65% by 2035.[126] The amended Directive obliges Member States to set up collection of hazardous household waste by 1 January 2025.[127]

The Directive sets out basic definitions and principles in relation to the management of waste, including that waste needs to be managed in such a manner that it does not endanger human health and harm the environment, pose risk to water, air, soil, plants or animals, cause a nuisance through noise or odours, or adversely affect the countryside or places of special interest. It establishes a five-step hierarchy in the management of waste that respects the following order: prevention, preparing for re-use, recycling, other recovery, eg energy recovery and, disposal.[128] The Waste Framework Directive sets out the definitions of, among other things, waste, recycling and recovery, hazardous waste and by-products,[129] non-hazardous waste, municipal waste, construction and demolition waste, food waste, material recovery, backfilling, and an extended producer responsibility scheme. In the context of energy, material recovery is defined to exclude energy recovery and the reprocessing into materials that are to be used as fuels or other means to generate energy.[130]

The Directive also sets an end-of-waste criteria when waste ceases to be classified as such under the definitions of the Directive following recovery, including recycling, which includes conditions such as that the material or object in question is commonly used for specific purposes, and that its use will not have adverse impact on the environment or human health.[131] In addition, it states that end-of-waste materials that will be used as fuels or other means to generate energy, or to be incinerated, backfilled or landfilled, shall not be calculated towards the achievement of recycling targets.

The Commission is currently working on a revision of the Waste Framework Directive.[132]

Wave and tidal energy

The Commission's Communication Transforming the EU's Blue Economy for a Sustainable Future[133] sets out its agenda for building a sustainable blue economy across the EU.

As defined in the agenda, the blue economy comprises all industries and sectors related to oceans, seas and coasts, based either in the marine environment (eg shipping, fisheries, energy generation) or on land (eg ports, shipyards, land-based aquaculture and algae production, coastal tourism). As a fast-growing and evolving segment of the economy, it also hosts other innovative sectors, such as ocean renewable energy, blue bio-economy, bio-technology and desalination.

The plan looks to align ocean policy with Europe's economic policy and incorporates sustainability at the core of its commitments. This approach suggests that businesses which have a positive impact on the environment, eg by using or generating renewable resources, preserving marine ecosystems, or reducing pollution will be incentivised, while others will be required to reduce their environmental footprint. The plan acknowledges the interconnectedness between different sectors of the blue economy and therefore aims to find common ground, encourage cooperation and achieve coherence between the relevant stakeholders. It also emphasises the need for investment in research, innovation and skills.

Given the wide scope of the blue economy, the agenda lists a number of actions in a range of areas such as zero pollution, the circular economy, biodiversity, ocean data, blue skills and jobs, and maritime spatial planning. In light of this, the Commission plans to create a Blue Forum to facilitate discussions between offshore operators, stakeholders and scientists engaged in relevant fields, such as fisheries, aquaculture, shipping, tourism and renewable energy. It also looks to promote the use of EU funds to green maritime transport by encouraging the use of short-sea shipping, renovating the EU's maritime fleet in order to increase its energy efficiency, and helping to achieve zero-emission ports, eg by facilitating discussions between relevant stakeholders on best practices and initiatives to green up ports. The Commission also proposes to revise the regulation on ship recycling and the EU requirements for decommissioning of offshore platforms to guarantee protection of the marine environment. It also considers proposing legally binding EU targets to restore degraded ecosystems, more specifically major habitats of fish spawning and nursery and in areas with the greatest potential for CCS.

E.13 Circular economy action plan

The Commission's Circular Economy Action Plan ("CEAP") includes both legislative and non-legislative initiatives for the efficiency and sustainability of product design and consumption, the prevention of waste and the retention of resources within the EU economy.

The Commission's Communication on the CEAP[134] sets out the following priorities, which in many cases link with other areas of legislative development:

- Making the circular economy work for people, regions and cities: ensuring that its instruments in support of skills and job creation also contribute to accelerating the transition to a circular economy.
- Less waste, more value: creating a well-functioning EU market for secondary raw materials and addressing waste exports from the EU.
- A sustainable product policy framework: making sustainable products the norm in the EU through design and empowering consumers and public buyers.
- Key product value chains: focusing on the sectors that use most resources and where the potential for circularity is high, such as electronics and ICT, batteries and vehicles, packaging, plastics, textiles, construction and buildings, food, water and nutrients. This includes a proposal for a new regulatory framework for batteries (see section F).
- Cross-cutting actions: recognising circularity as a prerequisite for climate neutrality, integrating the circular economy objective with financial stimulation (such as the Taxonomy Regulation; see section J) and driving the transition through research, innovation and digitalisation.
- Leading efforts at global level: initiating a new Global Alliance on Circular Economy and Resource Efficiency ("GACERE") to develop initiatives and partnerships related to the circular

economy. Circular economy objectives will also be included in free trade agreements, in bilateral, regional and multilateral processes and agreements, and in EU external policy funding instruments.

- Monitoring progress: updating the Circular Economy Monitoring Framework to reflect new policy priorities and develop further indicators on resource use, including consumption and material footprints.

Several measures have since been adopted on the basis of the CEAP:

- Sustainable Products Initiative;[135]
- EU strategy for sustainable and circular textiles;[136]
- Proposal for a revised Construction Products Regulation;[137]
- Proposal for Empowering Consumers in the Green Transition;[138]
- Revision of the Industrial Emissions Directive;[139]
- Revision of EU rules on Packaging and Packaging Waste;[140]
- Proposal for a Directive on Green Claims;[141]
- Proposal on common rules promoting the repair of goods; and [142]
- Circular economy monitoring framework.[143]

E.14 Carbon capture and storage

CCS directive

The climate change and renewable energy package includes a directive that provides a framework for CCS in the EU ("CCS Directive") supporting CCS as an emissions reduction option.

The key provisions of the CCS Directive include:

- a permit-based CCS storage regime to be administered by Member States and the amendment of existing EU legislation that prohibits or inhibits CCS;[144]
- a regime for operators holding permits to pass long-term liability for leakage from storage sites to the licensing Member State, provided certain hand-over criteria are met;[145] and
- requirements for all new combustion plants in the EU built without CCS to have space for CCS equipment and to have carried out studies into the availability of storage sites and the feasibility of 'retro-fitting' capture equipment.[146]

By joining up the funding mechanism under the EU ETS Directive and the provisions of the CCS Directive, the Climate Change Package provides that CCS is financially incentivised through the EU ETS.

As a result of the CCS Directive, CO_2 stored in geological formations is not to be classed as 'emitted' for the purposes of the EU ETS so that credit is given to power stations with CCS technology which are not to be required to surrender allowances for CO_2 which is stored.

There are two types of permits under the CCS Directive:

- an exploration permit, which permits certain specified exploration works to be carried out and entitles the permit holder, on an exclusive basis, to explore within the area covered by the permit for appropriate geological formations;[147] and
- a storage permit, which relates to the development and utilisation of geological formations contained in the permit area as storage sites for CO_2 and permits the injection of CO_2 to such formations.[148]

The criteria for the grant of a storage permit are rigorous and involve substantial site characterisation to assess its suitability for permanent storage. Applicants must also satisfy technical and financial requirements. As well as delineating the storage complex, storage permits are to contain a number of important provisions including the requirements for operating the storage facility, the total quantity of CO_2 to be stored, the requirements with regard to the composition of the CO_2 stream and an approved monitoring plan.[149]

Permits are to be issued by the competent authority in each Member State. The Commission proposes to review and comment on each individual storage permit application before it is awarded, and Member States must take the Commission's comments into consideration.[150]

As part of the permitting regime, Member States may require operators to lodge financial security for their prospective liabilities before the injection of CO_2 into a storage facility commences.[151] The scope of these liabilities and the form that the security will take is a matter for individual Member States to decide. In addition, Member States are entitled to require a contribution from the operator to cover future liabilities as a condition of the handover of responsibility. Member States may determine the amount of this contribution, which must be at least equal to the cost of monitoring the site for 30 years after decommissioning.[152]

New power plants

CCS for new power plants is not compulsory, however, the operators of all new combustion plants in the EU with a capacity in excess of 300MW that are built without CCS capabilities must assess whether suitable storage sites are available, whether transport facilities are technically and economically feasible and whether it is technically and economically feasible to retrofit the plant for CO_2 capture. The relevant competent authority in the Member State should also ensure that the operator has secured suitable space on the site for the installation of equipment necessary to capture and compress CO_2.[153]

By amending directives relating to the waste and ground water to permit the injection of CO_2 into storage sites, the Climate Change Package removes a significant part of the current prohibitions on CCS under EU legislation.

E.15 European climate pact

The Commission has adopted the Communication on the European Climate Pact,[154] which is a non-legislative initiative under the EGD. The pact is EU-wide and provides a forum for citizens, communities and organisations to connect, learn and share knowledge on climate change, and develop and implement solutions to the challenges posed by climate change.[155] The pact aims to help spread science-based information on climate action, and endeavours to support emerging and already existing climate initiatives, eg by providing an overview of available funding and the finances needed to support initiatives. Initially, the focus of the pact is on green areas, green transport, green buildings and green skills, with a view to expand to other areas in the future (such as healthy food and sustainable diets, sustainable production and consumption, quality of soils, rural and coastal areas, and oceans).

E.16 Research and innovation

The EGD aims to mobilise research and foster innovation to achieve a greener Europe, doing so mainly through Horizon Europe, the EU's key funding programme for research and innovation with a budget of €95.5 billion.

To maintain European technological leadership and expand export opportunities, the EU has developed a forward-looking energy and climate related research and innovation ("R&I") strategy, under which it has enhanced the Strategic Energy Technology Plan ("SET Plan"). The SET Plan aims to accelerate the development and deployment of low-carbon technology. The main instruments of the SET Plan are the European Technology and Innovation Platforms ("ETIPs"), the European Energy Research Alliance ("EERA") and the SET Plan Information System ("SETIS").

The ETIPs support the implementation of the SET Plan and bring together Member States, industry and researchers in key areas. They also promote the market uptake of key energy technologies by pooling funding, skills and research facilities.

The areas in which ETIPs have been active include wind, photovoltaic ("PV"), ocean energy, sustainable nuclear energy, geothermal energy, renewable heating and cooling, carbon capture and storage ("CCS"), zero emission fossil fuel power and smart networks for energy transition.

F. Nuclear energy

Nuclear power in the EU is governed by a number of measures to ensure high standards of safety and management of waste and facilitated by Euratom's research and market administration. Nuclear power is considered a low-carbon energy and is included under the EU green taxonomy.[156]

F.1 Nuclear safety

Under the Nuclear Safety Directive[157], all new construction licences have to include a 'high level EU-wide' safety objective to prevent nuclear accidents and radioactive leaks. The directive also imposes a higher level of responsibility on licence holders in respect of nuclear safety, with a requirement for periodic national safety assessments. While the Nuclear Safety Directive strengthens the independence of NRAs, it requires them to improve education and training and to carry out peer reviews every six years, with reporting every ten years.

Three further directives govern the treatment of radioactive waste which established a system to supervise and control shipments of radioactive waste and spent fuel.[158] The directives impose obligations on Member States to establish and maintain a framework for the management of such materials[159] and set permitted levels of radiation to which workers can be exposed, including when handling radioactive waste.[160]

F.2 Euratom

The European Atomic Energy Community ("Euratom")[161] is a single market for the trade in nuclear materials and technology. While Euratom is independent from the EU, it is governed by many of its institutions, including the Commission, and financed through the common budget. The EU Member States are full members of Euratom. Switzerland has the status of an associated state.[162] The cooperation between Euratom and the UK is governed by the Euratom-UK Agreement for Cooperation on the Safe and Peaceful use of nuclear energy.

Under Article 2 of the Euratom Treaty[163], the functions of Euratom include:

- promote research and ensure the dissemination of technical information;
- establish uniform safety standards to protect the health of workers and of the general public and ensure that they are applied;
- facilitate investment and ensure, particularly by encouraging ventures on the part of undertakings, the establishment of the basic installations necessary for the development of nuclear energy in the EU;
- ensure that all users in the Community receive a regular and equitable supply of ores and nuclear fuels;
- make certain, by appropriate supervision, that nuclear materials are not diverted to purposes other than those for which they are intended;
- exercise the right of ownership conferred upon it with respect to special fissile materials;
- ensure wide commercial outlets and access to the best technical facilities by the creation of a common market in specialised materials and equipment, by the free movement of capital for investment in the field of nuclear energy and by freedom of employment for specialists within the Community; and
- establish with other countries and international organisations such relations as will foster progress in the peaceful uses of nuclear energy.

Euratom's research activities cover both fission and fusion energy, and it is a signatory of the International Fusion Energy Organization ("ITER") Agreement[164] with six other member parties to demonstrate the scientific and technological feasibility of fusion energy for peaceful purposes.

G. Electricity storage

Energy storage is integral to the viability of key renewable energy sources ("RES") like solar and wind, given that they are only intermittent electricity generators. Due to this intermittency, electricity needs to be stored at times of generation excess so that it can be released into the system later at times of interruption, in order to smoothen out the overall output of the plant.

Similarly, storage would generally enable network operators to balance the grid more easily when faced with a greater proportion of intermittent generation, allowing for the system to adapt better to capacity peaks and lows, avoiding potential outages and contributing to a more efficient running of the network. At the same time, storage arguably allows for a more sustainable approach to energy production, as excess generation would not be lost but could be released back into the network at a later time, therefore reducing the need for additional generation.

G.1 Batteries regulation

The Commission has proposed a new Batteries Regulation[165] to address the full life cycles of batteries covering the production, use and end-of-life stage of batteries, considerably extending the regulatory framework for batteries compared to the current Batteries Directive, which had only addressed the end-of-life stage of batteries. On 17 March 2022, the Council adopted a general approach based on the proposal.[166]

The overarching aim of the proposed regulation is the harmonisation of rules concerning batteries in the internal market to create a level playing field and stimulate sustainable investment in the larger deployment of battery solutions. At the same time, the new regime recognises the risks batteries can pose to the environment and health and safety, implementing more stringent requirements to ensure a safe life cycle of batteries and mitigate possible negative consequences. Overall, the proposed regulation envisages a stepped approach to reflect a gradual increase in ambition over time.

The proposal outlines numerous sustainability and safety requirements which will come into force gradually, eg, 72 months after entry into force, batteries must meet certain specifications related to their electrochemical performance and durability to be placed on the market. It also introduces a set standard of assessment for all batteries (conformity assessment) under which manufacturers must complete an EU declaration of conformity which states that conformity with the sustainability, safety and labelling requirements of the Regulation have been demonstrated. Additionally, there will be an obligation for economic operators that place on the market rechargeable industrial batteries with a capacity above 2kWh and electric vehicle batteries to establish supply chain due diligence policies.

The proposal also sets out a number of end-of-life obligations such as a requirement for producers to register with the competent authority in the relevant Member State and demonstrate the measures that were put in place to meet the producers' responsibility obligations and the separate collection obligations. Moreover, producers will have to ensure the collection of all waste portable batteries, regardless of their nature, brand or origin, with collection targets set out as follows: 24 months after entry into force: 45%; 72 months after entry into force: 65%; and 96 months after entry into force: 70%.

Collected waste batteries are prohibited from being landfilled or incinerated and must enter a recycling process. In addition, the Regulation states that 48 months after entry into force, the Commission will set up an electronic exchange system for battery information which will contain information and data on rechargeable industrial batteries and electric vehicle batteries with internal storage and capacity above 2kWh. For the purposes of this system, each such battery placed on the market or put into service must have an electronic record (a battery passport).

G.2 European battery alliance

The European Battery Alliance is a cooperation platform between the Commission, interested Member States, the EIB and relevant industrial stakeholders and innovators. Its main objective is to develop an innovative, competitive and sustainable battery value chain in Europe that would accelerate the adoption of low-emission mobility and increase energy storage capacity. It has attracted 440 industrial actors and around €100 billion in investment commitments.[167] The alliance played an integral part in the development of the EU Commission's Strategic Action Plan on Batteries, which includes measures on access to raw materials, battery cell manufacturing at scale, sustainable batteries, research, innovation and skills.[168]

G.3 Critical Raw Materials Act

The Commission has also identified a number of products on which the EU is highly dependent, including rare earths and other raw materials needed for renewable energy generation and electricity storage solutions. To ensure the EU's access to a secure, diversified, affordable and sustainable supple of critical raw materials, the Commission published a proposal for the Critical Raw Materials Act ("CRMA").[169] It includes several diversification targets for 2030:

- the EU's extraction capacity for critical raw materials shall be able to produce 10% of the EU's annual consumption;
- the EU's processing capacity for critical raw materials shall be able to produce 40% of the EU's annual consumption; and
- the EU's recycling capacity for critical raw materials shall be able to produce 15% of the Unions annual consumption.

The proposed CRMA also includes obligations for certain large companies to perform audits of their strategic raw materials supply chains.

H. New Industrial Strategy

The New Industrial Strategy[170] was designed to support the EU's climate neutrality goals and aims to modernise and decarbonise energy intensive industries. The strategy contains several measures for the energy sector, including a strategy for smart sector integration (linking different sectors in order to use electricity, gas and liquid fuels more effectively), a common European energy data space (to enhance the innovative capacity of the energy sector), and the European Clean Hydrogen Alliance ("ECHA") (to support the implementation of the hydrogen strategy (see section E.11). The strategy incorporates learnings from the first year of the pandemic and focuses on increasing the resilience of the EU's single market by identifying and addressing strategic dependencies, among other things. An annual analysis of the state of the single market is included, which focuses on 14 industrial ecosystems, including renewables and energy intensive industries.

The updated Industrial Strategy also notes a number of other planned measures for support of the green and digital transition, including the establishment of an Energy and Industry Geography Lab to provide geospatial information for companies and energy infrastructure planners, carbon contracts for difference (CCfDs) and measures to support the uptake of corporate renewable power purchase agreements.

The New Industrial Strategy is complemented by the Green Deal Industrial Plan, which aims to improve the competitiveness of Europe's net-zero industry by providing a more supportive investment environment.[171]

I. Offshore gas

I.1 Overview

The gas market in the EU shares several aspects of its legislative framework with the electricity market. For details of the unbundling regime, regulatory oversight and NCs applicable to gas activities as for electricity (see section B). Certain aspects of the gas market are however covered by separate regimes.

Gas is also covered by the TEN-E Regulation for trans-European energy infrastructure (see section C). However, in line with the objectives of the Green Deal, the infrastructure categories eligible for support under the TEN-E Regulation exclude natural gas (as well as oil) infrastructure.

Natural gas is included in the EU taxonomy framework under the transitional activity category of the Taxonomy Regulation; such activities support the energy transition in a manner that is considered consistent with that path to net zero (see section J).

I.2 Access to storage and LNG facilities

The Gas Directive establishes legal and functional unbundling rules for storage system operators that are part of supply undertakings[172] and enhances the NRAs' powers to manage any access to gas storage[173] (see section B).

I.3 Upstream hydrocarbon resources

Generally, Member States have sovereign rights over hydrocarbon resources located within their territories. It is up to each Member State to determine the precise geographical areas where the rights to prospect, explore and produce hydrocarbons may be exercised. It is also the Member States' responsibility to authorise particular entities to exercise such rights.[174]

1.4 Hydrocarbons Licensing Directive

The Hydrocarbons Licensing Directive[175] concerns conditions imposed on the grant and use of authorisations for the prospection, exploration and production of hydrocarbons.

The Hydrocarbon Licensing Directive provides that there must be limits to the geographical area and duration of an authorisation. These limits must be proportionate and should be determined based on what is justified to ensure the best possible exercise of the rights granted, taking into account both economic and technical factors.[176] The aim of this is to prevent any single entity from having exclusive rights to an area where the prospection, exploration and production could be more effectively carried out by several entities. The provisions that reserve the right to obtain authorisations for a single entity for a specific geographical area within the territory of a Member State were abolished in 1997 by Member States.

Procedures for granting authorisation must be transparent and based on an objective and non-discriminatory criteria[177] and the application process must be open to any interested entities.[178] Selection from among the various entities must be based on criteria relating to their technical and financial capabilities, the way in which they propose to prospect, explore and/or bring into production the hydrocarbons from the geographical area in question and, if the authorisation is put up for sale, the price that the entity is prepared to pay to obtain the authorisation. All information relating to the authorisation (type of authorisation, geographical area that may be applied for in whole or in part, deadline envisaged for granting the authorisation, selection criteria, etc) should be published in the OJEU at least 90 days before the deadline for the submission of applications.[179]

The Hydrocarbons Licensing Directive provides Member States with the right to grant access to these hydrocarbon resources by granting rights; however, Member States may impose requirements further to considerations of national security, public safety, public health, security of transport, protection of the environment, protection of biological resources, the planned management of hydrocarbon resources or to the payment of a financial contribution or a contribution in hydrocarbons.[180] The directive also includes principles of reciprocity with countries outside the EU. Entities of a particular Member State must receive treatment in third countries that is comparable to that which the entities of third countries receive in the EU.[181]

Member States must provide an annual report containing information[182] on the geographical areas that have been opened, the authorisations granted, the entities holding those authorisations and the available reserves in their territory.

The Directive on coordinating the procurement procedures of entities operating in the water, energy, transport and postal services sectors[183] runs concurrently with the Hydrocarbons Licensing Directive.

1.5 Offshore Safety Directive

The Offshore Safety Directive[184] applies to existing and future installations and operations. The directive includes provisions that limit its applicability to landlocked Member States and Member States with no offshore activities; landlocked countries need only transpose the directive once a company registers in the country and conducts operations outside of the EU.[185]

The main features of the Offshore Safety Directive include:[186]

- provisions on minimum conditions for safe offshore oil and gas operations,[187] including the submission by operators of a major hazards report prior to commencement of offshore operations;[188]
- provisions improving the response mechanism for accidents and requiring operators to include emergency plans[189] as well as an assessment of oil spill response effectiveness;[190]
- the requirement that oil and gas operations only be conducted by operators appointed by licensees or licensing authorities;[191]
- provisions imposing financial liability for environmental damage on licence holders (not operators)[192] and extending area of liability for all damage from territorial waters of the Member State to the entire continental shelf area;[193]
- provisions ensuring the independence and objectivity of the competent authority, ie Member States must ensure a clear separation between regulatory/environmental functions on the one hand and economic functions on the other so as to avoid conflicts of interest;[194]
- the requirement that licensing authorities consider whether potential licensees have adequate provision for liabilities potentially deriving from operations;[195]
- rules on transparency and sharing of information;[196] and
- cooperation between Member States with regard to emergency response plans and trans-boundary emergency preparedness and response.[197]

The Offshore Safety Directive does not require mandatory financial security to be provided.

J. Energy trading

J.1 REMIT

The Regulation on Wholesale Energy Market Integrity and Transparency ("REMIT")[198] is applicable to energy companies in Europe and contains rules that prohibit the use of inside information in relation to wholesale energy products ("WEPs"). It requires the public disclosure of that inside information and prohibit certain behaviour constituting market manipulation. REMIT was set up as part of a dedicated market integrity and transparency framework for the electricity and gas wholesale markets with a central reporting point at EU level and an EU-wide monitoring scheme. Prior to REMIT, the monitoring of energy markets was sector-specific and conducted by each Member State. As the structure of the energy markets becomes increasingly pan-European it is more difficult for national regulators to function effectively as they do not have access to Europe-wide information.

J.2 MiFID II and MiFIR

MiFID II[199] and MiFIR[200] set out the legal framework governing the requirements applicable to investment firms, trading venues, data reporting service providers and third country firms providing investment services/activities in the EU. Importantly for the energy sector, emission allowances fall within the scope of MiFID (and MiFID II) and are classified as financial instruments, so that both derivatives and secondary spot markets in emission allowances will be subject to financial market regulation.

J.3 EMIR

EMIR[201] introduced significant changes to the over-the-counter derivatives market by mandating central clearing for standardised contracts and imposing risk mitigation standards for non-centrally cleared contracts. EMIR provides a framework for these new obligations; however, the precise details, which are necessary for market participants to comply with the regulation, are set out in subordinate legislation. A number of pieces of subordinate legislation have come into force in the form of delegated regulations and regulatory technical standards.

J.4 SFTR

The Securities Financing Transactions Regulation ("SFTR")[202] was published following recommendations by the Financial Stability Board ("FSB") and the European Systemic Risk Board to mitigate risks in shadow banking and increase transparency in securities lending and repurchase. Under the SFTR, firms must report their securities financing transactions ("SFTs") to a trade repository that is registered by the European Securities and Markets Authority ("ESMA"). Broadly, SFTs are securities or commodities that are used to borrow cash, or cash used to borrow securities or commodities. Under the SFTR, a commodity is any good of a fungible nature that can be delivered; this includes metals, their ores and alloys, agricultural products and energy.

K. Sustainable finance

The EU has identified sustainable finance as a key factor in delivering on the policy objectives under the European Green Deal. In addition to public investments, investments from private investors are needed to finance the energy transition.

In July 2021, the Commission published the revised Sustainable Finance Strategy.[203] This lists over 50 legislative and non-legislative initiatives to be implemented. Building blocks of the initiative are:

- Taxonomy;
- Disclosure Framework; and
- Investment tools.

Currently, the EU is in the process of implementing these initiatives.

K.1 Taxonomy Regulation

A key component of the Sustainable Finance Strategy is the development of an EU-wide green taxonomy on environmentally sustainable activities ("Taxonomy") that provides a common language of what is 'sustainable'.[204] It is a classification system, establishing a list of environmentally sustainable activities.

The Taxonomy Regulation sets out four sustainability conditions that economic activities must meet to ensure they qualify as environmentally sustainable for the purposes of the regulation. By setting these environmentally sustainable conditions, the regulation seeks to fulfil its six environmental objectives, which are: (i) climate change mitigation, (ii) climate change adaptation, (iii) sustainable use and protection of water and marine resources, (iv) transition to a circular economy, (v) pollution prevention and control and protection, and (vi) restoration of biodiversity and ecosystems ("Environmental Objectives").

Under the sustainability conditions set out in the Taxonomy Regulation, an economic activity qualifies as environmentally sustainable if it:

- contributes substantially to one of the Environmental Objectives;
- does no significant harm to any of the Environmental Objectives;
- is carried out in compliance with minimum social and governance safeguards set out in the Taxonomy Regulation (these safeguards align with the OECD Guidelines on Multinational Enterprises and the UN Guiding Principles on Business and Human Rights); and
- complies with the technical screening criteria to be established by the Commission under the Taxonomy Regulation.

The Taxonomy Regulation introduces new disclosure obligations for financial market participants (such as asset managers), supplementing the obligations under the Disclosures Regulation. The Taxonomy Regulation also introduces new disclosure obligations for some corporates, supplementing the disclosure obligations under the Non-Financial Reporting Directive ("NFRD"). The intention of these disclosures is to enable asset owners, asset managers and investors to make 'like-for-like' comparisons between financial products and investee companies, the theory being that this will tackle one of the most significant obstacles in the ESG markets today.

The Taxonomy Regulation covers multiple sectors, including agriculture and forestry, manufacturing, electricity, gas, steam and air conditioning supply, water, sewerage, waste and remediation, transportation and storage, and building. Typically, energy intensive activities such as iron and steel manufacturing, public transport, construction, and livestock farming can qualify as environmentally sustainable if they comply with the technical screening criteria.

The Taxonomy Regulation captures both the construction and operation of electricity generation facilities that produce electricity using gaseous and liquid fuels (such as oil and gas); however, it excludes power generation using solid fossil fuels and other solid fuels such as waste-to-energy from the remit of sustainable activity. The regulation captures both the construction and operation of electricity generation facilities, that produce electricity using gaseous and liquid fuels (such as oil and gas).

The Delegated Act supplementing Article 8 of the Taxonomy Regulation[205] requires both financial and non-financial companies to provide information to investors about the environmental performance of their assets and economic activities.

Under the Complementary Climate Delegated Act, the Commission included specific nuclear and gas energy activities in the list of economic activities covered by the EU taxonomy.[206]

K.2 EU Green Bond Standard

The EGD underlined the need for long-term signals to direct financial and capital flows to green investments which is addressed under the EGD's Investment Plan[207] in the form of an EU green bond standard ("EUGBS"). The European Parliament and the Council reached a provisional agreement on a European Green Bond Regulation on 1 March 2023.[208]

The EUGBS is a certification scheme which signals to investors that the use of proceeds is 85% aligned with the EU Taxonomy. Issuers can also adhere to the EU Green Bond Framework, a protocol that confirms the voluntary alignment of the green bonds issued under the EUGBS. Under the EU Green Bond Framework, issuers must explain how their strategy is in alignment with the EU's environmental objectives and must provide details on the most important aspects of their use of proceeds, the processes they employ, and their reporting on green bonds. In addition to this mandatory list, issuers are also encouraged to consider how they can robustly demonstrate the alignment of their strategy with the EU's Environmental Objectives.

K.3 Sustainable Finance Disclosures Regulation

The Sustainable Financial Disclosures Regulation ("SFDR") sets out sustainability disclosure obligations for manufacturers of financial products and financial advisers toward end-investors. It does so in relation to the integration of sustainability risks by financial market participants (ie asset managers, institutional investors, and all entities offering financial products that involve managing clients' money) and financial advisers in all investment processes and for financial products that pursue the objective of sustainable investment. The SFDR aims to achieve harmonised disclosure requirements for investment products that promote environmental and/or social objectives and have 'sustainable investment' as their objective.

Further, the SFDR provides for disclosure obligations as regards adverse impacts on sustainability matters at entity and financial products levels, ie whether financial market participants and financial advisers consider negative externalities on environment and social justice of the investment decisions or advice and, if so, how this is reflected at the product level. The rationale behind requiring such disclosures is that investment decisions and financial advice might cause, contribute to, or be directly linked to, negative material effects on the environment and society, regardless of whether the investment strategy pursues a sustainable objective.

The scope of the SFDR[209] extends to the following participants, among others:

- Alternative Investment Fund Managers ("AIFMs");
- management companies falling under the Undertakings for the Collective Investment in Transferable Securities ("UCITS") framework;
- investment firms authorised under MiFID II providing portfolio management or investment advice;
- managers of qualifying venture capitals funds; and
- qualifying social entrepreneurship funds.

By Delegated Regulation dated 25 July 2022, the Commission adopted technical standards to be used when disclosing sustainability-related information under the SDFR.[210] By amending the Delegated Regulation, the Commission required financial market participants to disclose the extent to which their portfolios are exposed to gas and nuclear-related activities that comply with the Taxonomy Regulation.[211]

K.4 Corporate Sustainability Reporting Directive

The Corporate Sustainability Reporting Directive[212] ("CSRD") aims to equip investors and other stakeholders with access to the information needed to assess investment risks arising from climate change and other sustainability issues. It addresses the reporting gaps in the NFRD, as feedback from consultations on its implementation found that companies reported insufficient information or omitted information that investors and other stakeholders thought important, with an overall lack of trust in data that is difficult to compare between companies.

The CSRD also to extends the scope of companies covered and establish a set of sustainability standards that will ensure higher quality reporting, better comparability between companies as well as improved accessibility through digitalisation (the estimated total number of companies covered increased from 11,000 under the NFRD to 50,000 under the CSRD).

Additionally, the CSRD:

- requires the audit (assurance) of reported information; and
- requires companies to digitally 'tag' the reported information, so it is machine readable and feeds into the European single access point envisaged in the capital markets union action plan.

The CSRD sets out a transition period, so that the first companies must publish reports in the 2024 financial year.[213]

Endnotes

1. Articles 14 and 15 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005; Articles 32-34 Consolidated text: Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC secure third-party access; Article 6 Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).
2. Article 30 Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005; Article 36 Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
3. Article 63 Consolidated text: Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).
4. The unbundling provisions are contained in Articles 43 to 56 revised Electricity Directive ((EU) 2019/944) and Articles 9 to 11 and 14 Third Gas Directive.
5. Article 43 of the revised Electricity Directive and Article 9 of the Third Gas Directives.
6. Article 43 Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast); Article 9 Directive 2009/73/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing Directive 2003/55/EC.
7. Article 33 Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU (recast).
8. Article 44 revised Electricity Directive and Article 14 Third Gas Directive.
9. Article 45(1) revised Electricity Directive and Article 15(1) Third Gas Directive.
10. Article 44(2)(a) revised Electricity Directive and Article 14(2)(a) Third Gas Directive.
11. Article 45(1) revised Electricity Directive and 15(1) Third Gas Directive.
12. Article 44(5)(b) revised Electricity Directive and Article 14(5)(b) Third Gas Directive.
13. Article 44(1) revised Electricity Directive and 14(1) Third Gas Directive (approval by Commissioner).
14. Article 44(2)(c) revised Electricity Directive and 14(2)(c) Third Gas Directive.
15. Article 43(3) revised Electricity Directive and Article 9(8) Third Gas Directive.
16. Article 48(3) revised Electricity Directive and Article 19(3) Third Gas Directive.
17. Article 48(8) revised Electricity Directive and Article 19(8) Third Gas Directive.
18. Article 48(8) revised Electricity Directive and Article 19(8) Third Gas Directive.
19. Article 51 revised Electricity Directive and Article 22 Third Gas Directive.
20. Article 50 revised Electricity Directive and Article 21 Third Gas Directive.
21. Article 59(5) revised Electricity Directive and Article 41(5) Third Gas Directive.
22. Article 59(3)(d) revised Electricity Directive and Article 41(3)(d) of the Third Gas Directive.
23. Article 59(6)(h) revised Electricity Directive and Article 41 (5)(h) Third Gas Directive.
24. Article 43(8) revised Electricity Directive and Article 9(8) Third Gas Directive.
25. Article 52 revised Electricity Directive and Article 10 Third Gas Directive.
26. Article 53(3) revised Electricity Directive and Article 11(3) Third Gas Directive.
27. Article 53(1) revised Electricity Directive and Article 11(1) Third Gas Directive.
28. Article 53(2) revised Electricity Directive and Article 11(2) Third Gas Directive.
29. Article 53(5) revised Electricity Directive and Article 11(5) Third Gas Directive.
30. Directives 2003/54/EC and 2003/55/EC, respectively.
31. Article 57 revised Electricity Directive; Article 39 Third Gas Directive.
32. Article 37 Third Electricity Directive; Article 41 Third Gas Directive.
33. Article 58 (a) revised Electricity Directive; Article 40(a) Third Gas Directive.
34. Regulation (EU) 2015/1222 of 24 July 2015.
35. See https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%27s%2520Final%2520Assessment%2520of%2520the%2520EU%2520Wholesale%2520Electricity%2520Market%2520Design.pdf.
36. Regulation (EC) No 715/2009 of the European Parliament and of the Council of 13 July 2009 on conditions for access to the natural gas transmission networks and repealing Regulation (EC) No 1775/2005; Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity (recast).
37. ACER, which was established by rule 713/2009, is the European agency of energy regulators.
38. See www.entsoe.eu/network_codes/cacm/implementation/ccr.
39. See http://eur-lex.europa.eu/legal-content/EN/ALL/?uri=CELEX:32013R0984.
40. Articles 64 revised Electricity Directive and Article 40 Third Gas Directive.
41. It should be noted that the amount of CMP-relevant IP sides decreased from 251 in 2019 to 200 in 2020.
42. See www.acer.europa.eu/Publications/Congestion_9thEd_FINAL.pdf.
43. Regulation (EU) 2022/869 of the European Parliament and of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013.
44. Article 3(1) TEN-E Regulation.
45. Article 3(4) TEN-E Regulation.
46. Article 3(1) TEN-E Regulation.
47. Article 19 TEN-E Regulation.
48. Article 18 TEN-E Regulation.
49. Article 7(3) TEN-E Regulation.
50. Article 10(2) TEN-E Regulation.
51. Article 8(3) TEN-E Regulation.
52. Article 8(1) TEN-E Regulation.
53. Article 7(5) TEN-E Regulation.

54. 2021. For full list of PCI projects see https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32022R0564&qid=1663087079030.
55. Article 4(d) Regulation (EU) 2018/1999.
56. European Environmental Bureau, Power in Unity of 14 June 2023, https://eeb.org/wp-content/uploads/2023/06/Policy-Brief_Breaking-Borders_Interconnection-In-Europe.pdf.
57. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Powering a climate neutral economy: an EU Strategy for Energy System Integration, Brussels 08.07.2020.
58. See: https://ec.europa.eu/commission/presscorner/detail/en/IP_23_1591.
59. The Investment Plan was introduced on 14 January 2020. See 'The European Green Deal Investment Plan and Just Transition Mechanism explained', available at https://ec.europa.eu/commission/presscorner/detail/en/qanda_20_24.
60. Regulation (EU) 2021/1119 of the European Parliament and of the Council of 30 June 2021 establishing the framework for achieving climate neutrality and amending Regulations (EC) No 401/2009 and (EU) 2018/1999 ('European Climate Law'). Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A32021R1119&qid=1626362659911.
61. Article 4(1) European Climate Law.
62. Article 2(1) European Climate Law.
63. Article 4(1) European Climate Law.
64. Article 4(1) European Climate Law.
65. Article 4(3) European Climate Law.
66. Article 4(4) European Climate Law.
67. Article 5 European Climate Law.
68. Article 3 European Climate Law.
69. Article 3(4) European Climate Law.
70. Article 10 European Climate Law.
71. Article 7 European Climate Law.
72. See https://ec.europa.eu/commission/presscorner/detail/en/IP_21_3541.
73. Article 6 European Climate Law.
74. Article 25(1) RED II.
75. Articles 26-29 RED II.
76. At the time of publication, the agreed text had not yet been published. For a summary of the agreement see 'Press release from the Council of 30 March 2023', 249/23, available at www.consilium.europa.eu/en/press/press-releases/2023/03/30/council-and-parliament-reach-provisional-deal-on-renewable-energy-directive/pdf.
77. Council Regulation (EU) 2022/2576 of 19 December 2022 enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders.
78. Article 7 Council Regulation (EU) 2022/2576 of 19 December 2022 enhancing solidarity through better coordination of gas purchases, reliable price benchmarks and exchanges of gas across borders.
79. Regulation (EU) 2023/435 of 27 February 2023 amending Regulation (EU) 2021/241 as regards REPowerEU chapters in recovery and resilience plans and amending Regulations (EU) No 1303/2013, (EU) 2021/1060 and (EU) 2021/1755, and Directive 2003/87/EC.
80. At the time of publication the adopted text had not been published. However, that text that was voted on had been published: Directive (EU) 2023/.. of the European Parliament and of the Council of … amending Directive 2003/87/EC establishing a system for greenhouse gas emission allowance trading within the Union and Decision (EU) 2015/1814 concerning the establishment and operation of a market stability reserve for the Union greenhouse gas emission trading system, available at https://data.consilium.europa.eu/doc/document/PE-9-2023-INIT/en/pdf.
81. Article 9 revised EU ETS Directive.
82. Article 3ga revised EU ETS Directive.
83. Articles 3(b), 3a and Annex I revised EU ETS Directive.
84. Article 3ga revised EU ETS Directive.
85. Article 3gb revised EU ETS Directive.
86. Article 3d(1) revised EU ETS Directive.
87. Chapter Iva revised EU ETS Directive.
88. Article 30c revised EU ETS Directive.
89. Decision (EU) 2023/852 of the European Parliament and of the Council of 19 April 2023 amending Decision (EU) 2015/1814 as regards the number of allowances to be placed in the market stability reserve for the Union greenhouse gas emission trading system until 2030 (Text with EEA relevance).
90. Regulation (EU) 2023/857 amending Regulation (EU) 2018/842 on binding annual greenhouse gas emission reductions by Member States from 2021 to 2030 contributing to climate action to meet commitments under the Paris Agreement, and Regulation (EU) 2018/1999; Consolidated Regulation (EU) 2018/842 of the European Parliament and of the Council of 30 May 2018 on binding annual greenhouse gas emission reductions by Member States from 2021 to 2030 contributing to climate action to meet commitments under the Paris Agreement and amending Regulation (EU) No 525/2013 (Text with EEA relevance)Text with EEA relevance.
91. Annex I revised Effort Sharing Regulation.
92. Member states may only use 131 million credits for the respective periods from 2021-2025 and 2026-2030.
93. At the time of publication, the text of the regulation has not been published in the official journal. However, the adopted text has been available: Regulation (EU) 2023/.. of the European Parliament and of the Council establishing a carbon border adjustment mechanism, available at: https://data.consilium.europa.eu/doc/document/PE-7-2023-INIT/en/pdf.
94. Article 32 CBAM Regulation.
95. Article 21 CBAM Regulation.
96. Article 2 and Annex III CBAM Regulation.
97. Article 9(1) CBAM Regulation.
98. Article 9(4) CBAM Regulation.
99. Consolidated Council Directive 2003/96/EC of 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity.
100. Proposal for a Council directive restructuring the Union framework for the taxation of energy products and electricity (recast) of 14 July 2021, COM(2021) 563 final.
101. Regulation (EU) 2023/839 amending Regulation (EU) 2018/841 as regards the scope, simplifying the reporting and compliance rules, and setting out the targets of the Member States for 2030, and Regulation (EU) 2018/1999 as regards improvement in monitoring, reporting, tracking of progress and review; Consolidated regulation (EU) 2018/841 of the European Parliament and of the Council of 30 May 2018 on the inclusion of greenhouse gas emissions and removals from land use, land use change and forestry in the 2030 climate and energy framework, and amending Regulation (EU) No 525/2013 and Decision No 529/2013/EU (Text with EEA relevance) Text with EEA relevance.

102. Article 4(2) revised LULUCF regulation.

103. Article 4(2) and Annex IIa revised LULUCF regulation.

104. Consolidated text: Regulation (EU) 2019/631 of the European Parliament and of the Council of 17 April 2019 setting CO_2 emission performance standards for new passenger cars and for new light commercial vehicles, and repealing Regulations (EC) No 443/2009 and (EU) No 510/2011 (recast).

105. Regulation (EU) 2023/851 amending Regulation (EU) 2019/631 as regards strengthening the CO_2 emission performance standards for new passenger cars and new light commercial vehicles in line with the Union's increased climate ambition.

106. Article 1 Recast Emissions Standards Regulation.

107. Article 1(5) revised ESR.

108. Article 1(5) revised ESR.

109. Article 1(5a) revised ESR.

110. Article 8 revsied ESR.

111. Proposal for a Regulation of the European Parliament and of the Council of 15 December 2021 on methane emissions reduction in the energy sector and amending Regulation (EU) 2019/942, COM(2021) 805 final.

112. Proposal for a Directive if the European Parliament and of the Council on energy efficiency (recast) of 24 March 2023, 2021/0203(COD).

113. Consolidated Directive 2010/31/EU of the European Parliament and of the Council of 19 May 2010 on the energy performance of buildings (recast).

114. Proposal for a Directive of the European Parliament and of the Council on the energy performance of buildings (recast) of 15 December 2021, COM/2021/802 final.

115. Proposal for a Directive of the European Parliament and of the Council on the energy performance of buildings (recast) of 21 October 2022, 2021/0426(COD).

116. See: www.consilium.europa.eu/en/press/press-releases/2023/04/25/council-and-parliament-agree-to-decarbonise-the-aviation-sector/.

117. Proposal for a Regulation of the European Parliament and of the Council on the use of renewable and low-carbon fuels in maritime transport and amending Directive 2009/16/EC of 14 July 2021, COM(2021) 562 final.

118. Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32014L0094.

119. Article 4 Alternative Fuels Directive.

120. Article 7 Alternative Fuels Directive.

121. Proposal for a Regulation of the European Parliament and of the Council on the deployment of alternative fuels infrastructure, and repealing Directive 2014/94/EU of the European Parliament and of the Council of 16 July 2021, 2021/0223(COD).

122. See Articles 1 and 17 Renewable Energy Directive.

123. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, An EU Strategy to harness the potential of offshore renewable energy for a climate neutral future, Brussels 19.11.2020. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2020:741:FIN.

124. Regulation (EU) 2022/869 of the European Parliament of the Council of 30 May 2022 on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013.

125. Directive 2008/98/EC of the European Parliament and of the Council of 19 November 2008 on waste and repealing certain Directives. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=celex%3A32008L0098.

126. Article 10 Waste Framework Directive, amended.

127. Article 20 Waste Framework Directive, amended.

128. Article 4 Waste Framework Directive.

129. Article 3 Waste Framework Directive.

130. Article 1 Waste Framework Directive, amended.

131. Article 6 Waste Framework Directive.

132. See: https://environment.ec.europa.eu/topics/waste-and-recycling/waste-framework-directive_en.

133. Communication from the Commission to the European Parliament, the Council, The European Economic and Social Committee and the Committee of the Regions on a new approach for a sustainable blue economy in the EU Transforming the EU's Blue Economy for a Sustainable Future, Brussels 17.05.2021. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=COM:2021:240:FIN.

134. Communication from the Commission to the European Parliament, The Council, The European Economic and Social Committee and the Committee of the Regions: A new circular economy action plan (Brussels, 11.3.2020 COM(2020) 98 final).

135. See: https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/12567-Sustainable-products-initiative_en.

136. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee of the Regions regarding the EU Strategy for Sustainable and Circular Textiles of 30 March 2022, COM(2022) 141 final.

137. Proposal for a Regulation of the European Parliament and of the Council laying down harmonised conditions for the marketing of construction products, amending Regulation (EU) 2019/1020 and repealing Regulation (EU) 305/2011 of 30 March 2022, COM(2022) 144 final.

138. Proposal for a Directive of the European Parliament and of the Council amending Directives 2005/29/EC and 2011/83/EU as regards empowering consumers for the green transition through better protection against unfair practices and better information of 30 March 2023, COM(2022) 143 final.

139. Proposal for a Directive of the European Parliament and of the Council amending Directive 2010/75/EU of the European Parliament and of the Council of 24 November 2010 on industrial emissions (integrated pollution prevention and control) and Council Directive 1999/31/EC of 26 April 1999 on the landfill of waste of 5 April 2022, COM(2022) 156 final/3.

140. Proposal for a Regulation of the European Parliament and of the Council on packaging and packaging waste, amending Regulation (EU) 2019/1020 and Directive (EU) 2019/904, and repealing Directive 94/62/EC of 30 November 2022, COM(2022) 677 final.

141. Proposal for a Directive of the European Parliament and of the Council on substantiation and communication of explicit environmental claims (Green Claims Directive) of 22 March 2023, COM(2023) 166 final.

142. Proposal for a Directive of the European Parliament and of the Council on common rules promoting the repair of goods and amending Regulation (EU) 2017/2394, Directives (EU) 2019/771 and (EU) 2020/1828 of 22 March 2023, COM(2023) 155 final.

143. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Region on a revised monitoring framework for the circular economy of 15 May 2023, COM(2023)306 final.

144. Articles 5 to 11 CCS Directive.

145. Articles 12 to 20 CCS Directive.

146. Article 33 CCS Directive, amending Directive 2001/80/EC (OJEU L 309 of 27.11.2001, pp1-21).

147. Article 5 CCS Directive.

148. Article 6 CCS Directive.

149. Articles 7 and 8 CCS Directive.

150. Articles 8(2) and 10 CCS Directive.

151. Article 20 CCS Directive.

152. Article 20 CCS Directive.

153. Article 33 CCS Directive (Article 9a of the amended Directive 2001/80/EC; OJEU L 309 of 27.11.2001, pp1-21).

154. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, European Climate Pact, Brussels, 9.12.2020.

155. The communication was adopted on 9 December 2020.

156. Commission Delegated Regulation (EU) 2022/1214 of 9 March 2022 amending Delegated Regulation (EU) 2021/2139 as regards economic activities in certain energy sectors and Delegated Regulation (EU) 2021/2178 as regards specific public disclosures for those economic activities.

157. Was adopted in 2009 to establish a common safety framework in respect of nuclear installations, with legally binding principles in all Member States.

158. Council Directive 2006/117/Euratom on the supervision and control of shipments of radioactive waste and spent fuel.

159. Council Directive 2011/70/Euratom establishing a Community framework for the responsible and safe management of spent fuel and radioactive waste.

160. Council Directive 2013/59/Euratom of 5 December 2013 laying down basic safety standards for protection against the dangers arising from exposure to ionising radiation.

161. Most recently amended in 2012 - Treaty Establishing the European Atomic Energy Community (2012/C 327/01).

162. The cooperation between Euratom and the UK is governed by the Euratom-UK Agreement for Cooperation on the Safe and Peaceful use of nuclear energy.

163. See https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:11957A/TXT.

164. See www.iter.org/legal/status.

165. Proposal for a Regulation of the European Parliament and of the Council concerning batteries and waste batteries, repealing Directive 2006/66/EC and amending Regulation (EU) No 2019/1020. Available at https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52020PC0798&qid=1628768821203.

166. Proposal for a Regulation of the European Parliament and of the Council concerning batteries and waste batteries, repealing Directive 2006/66/EC and amending Regulation (EU) No 2019/1020 - General approach of 14 March 2022, 2020/0353.

167. See https://ec.europa.eu/growth/industry/policy/european-battery-alliance_en.

168. See https://eur-lex.europa.eu/resource.html?uri=cellar:0e8b694e-59b5-11e8-ab41-01aa75ed71a1.0003.02/DOC_3&format=PDF.

169. Proposal for a Regulation of the European Parliament and of the Council establishing a framework for ensuring a secure and sustainable supply of critical raw materials and amending Regulations (EU) 168/2013, (EU) 2018/858, 2018/1724 and (EU) 2019/1020.

170. Communication from the Commission to the European Parliament, The European Council, The Council, The European Economic and Social Committee and the Committee of the Regions: A new industrial strategy for Europe (Brussels, 10.3.2020 COM(2020) 102 final).

171. Communication from the Commission to the European Parliament, the European Council, the Council, the European Economic and Social Committee and the Committee of the Regions: A Green Deal Industrial Plan for the Net-Zero Age of 1 February 2023, COM(2023) 62 final.

172. Article 15 Gas Directive.

173. Articles 33 and 41(n) Third Gas Directive.

174. Article 2 Hydrocarbons Licensing Directive.

175. Consolidated Directive 1994/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons.

176. Article 3(2) and Article 4 of the Hydrocarbons Licensing Directive.

177. Article 5(1) and 5(4) Hydrocarbons Licensing Directive.

178. Article 5(2) and 5(3) Hydrocarbons Licensing Directive.

179. Article 3(2)a Hydrocarbons Licensing Directive.

180. Article 6(2) Hydrocarbons Licensing Directive.

181. Article 8(3) Hydrocarbons Licensing Directive.

182. Article 9 Hydrocarbons Licensing Directive.

183. Directive 2014/25/EU of the European Parliament and of the Council of 26 February 2014 on procurement by entities operating in the water, energy, transport and postal services sectors and repealing Directive 2004/17/EC.

184. Directive 2013/30/EU on safety of offshore oil and gas operations and amending Directive 2004/35/EC.

185. Article 41 Offshore Safety Directive.

186. See www.consilium.europa.eu/uedocs/cms_data/docs/pressdata/en/trans/137424.pdf.

187. Article 1(1) Offshore Safety Directive.

188. Articles 6(5), 6(6), 11(1)(e), 12 and 13 Offshore Safety Directive.

189. Articles 11(1)(g), 14 and 28 Offshore Safety Directive.

190. Article 14 Offshore Safety Directive.

191. Article 4(4) Offshore Safety Directive.

192. Article 7 Offshore Safety Directive.

193. Article 2(2) Offshore Safety Directive.

194. Article 8 Offshore Safety Directive.

195. Article 4(2)(c) and 4(3) Offshore Safety Directive.

196. Chapter V Offshore Safety Directive.

197. Article 27 Offshore Safety Directive.

198. Regulation no. 1227/2011 of 25 October 2011 on wholesale energy market integrity and transparency.

199. Directive 2014/65/EU of 15 May 2014 on markets in financial instruments and amending Directive 2002/92/EC and Directive 2011/61/EU (recast).

200. Regulation (EU) 600/2014 of 15 May 2014 on markets in financial instruments and amending Regulation (EU) no. 648/2012.

201. Regulation (EU) 648/2012 of 4 July 2012 on over-the-counter ("OTC") derivatives, central counterparties and trade repositories.

202. Regulation (EU) 2015/2365 of 25 November 2015 on transparency of securities financing transactions and of reuse and amending Regulation (EU) no. 648/2012.

203. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Strategy for Financing the Transition to a Sustainable Economy of 6 July 2021, COM(2021) 390 final.

204. Regulation (EU) 2020/852 of the European Parliament and of the Council of 18 June 2020 on the establishment of a framework to facilitate sustainable investment, and amending Regulation (EU) 2019/2088.

205. Commission Delegated Regulation (EU) 2021/2178 of 6 July 2021 supplementing Regulation (EU) 2020/852 of the European Parliament and of the Council by specifying the content and presentation of information to be disclosed by undertakings subject to Articles 19a or 29a of Directive 2013/34/EU concerning environmentally sustainable economic activities, and specifying the methodology to comply with that disclosure obligation.

206. Commission Delegated Regulation (EU) 2022/1214 of 9 March 2022 amending Delegated Regulation (EU) 2021/2139 as regards economic activities in certain energy sectors and Delegated Regulation (EU) 2021/2178 as regards specific public disclosures for those economic activities.

207. Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions, Sustainable Europe Investment Plan, European Green Deal Investment Plan, Brussels 14.01.2020.

208. See: https://finance.ec.europa.eu/sustainable-finance/tools-and-standards/european-green-bond-standard_en.

209. Regulation (EU) 2019/2088 of the European Parliament and of the Council of 27 November 2019 on sustainability-related disclosures in the financial services sector.

210. Corrigendum to Commission Delegated Regulation (EU) 2022/1288 of 6 April 2022 supplementing Regulation (EU) 2019/2088 of the European Parliament and of the Council with regard to regulatory technical standards specifying the details of the content and presentation of the information in relation to the principle of 'do no significant harm', specifying the content, methodologies and presentation of information in relation to sustainability indicators and adverse sustainability impacts, and the content and presentation of the information in relation to the promotion of environmental or social characteristics and sustainable investment objectives in pre-contractual documents, on websites and in periodic reports.

211. Commission delegated Regulation (EU) 2023/363 of 31 October 2022 amending and correcting the regulatory technical standards laid down in Delegated Regulation (EU) 2022/1288 as regards the content and presentation of information in relation to disclosures in pre-contractual documents and periodic reports for financial products investing in environmentally sustainable economic activities.

212. Directive (EU) 2022/2464 of the European Parliament and of the Council of 14 December 2022 amending Regulation (EU) No 537/2014, Directive 2004/109/EC, Directive 2006/43/EC and Directive 2013/34/EU, as regards corporate sustainability reporting (Text with EEA relevance).

213. Article 5 CSRD.

Energy law in Albania

Recent developments in the Albanian energy market

Krenar Loloci, managing partner, Loloci & Associates

Energy sector

Legal framework

Law no. 61/2020 "On amendments and additions to Law no. 43/2015 "On Energy Sector", as amended", was approved on 10 October 2020 and added the concept of the Compliance Officer ("CO"). The legislation defines the CO as the independent natural or legal person, designated by the Distribution System Operator ("DSO"), who is in charge of monitoring and reporting on the implementation of the Compliance Programme. Such Programme is provided to ensure that provisions of Article 54(3) of Law no. 43/2015 "On Energy Sector", as amended ("Law on Energy") are observed. Article 54(3) aims to ensure that the Transmission System Operator ("TSO") exercises its activity separately from other activities of the power sector, such as production, distribution, trading, and the supply of electricity. In this regard, Article 54(3) of the Law on Energy provides that, from 1 January 2016, a given subject cannot, at the same time:

- exercise control, either directly or indirectly, over a licensee that performs one of the activities of production, or the supplying of electricity and natural gas, and exercises control or any other right over the TSO or the transmission grid;
- exercise control, either directly or indirectly, over the TSO or the transmission grid and exercise control or any other right over a licensee that performs any of the activities of production or the supplying of electricity and of natural gas;
- appoint members of the supervisory board, board of directors, or bodies that legally represent the TSO or the transmission grid and, directly or indirectly, exercise control or any other right over a licensee performing any of the activities of production or the supplying of electricity and natural gas; and
- be a member of the supervisory board, board of directors, or other bodies representing the licensee to the licensees that perform the activity of the production or supply of electricity and natural gas and the activity of the TSO or the transmission grid.

Law no. 61/2020 has also amended Article 31(1) of the Law on Energy. Under this amendment, the new interconnection lines built by private investors will be approved by the decision of the Council of Ministers of the Republic of Albania ("CM"), upon the proposal of the minister in charge of the power sector.

Price de-regulation

The Albanian Ministry of Energy and Industry ("MEI") has approved Order 28/2021 regarding the approval of the roadmap for opening the market and de-regulating the price of electricity. According to this Order, the Law on Energy has transposed the requirement of the Electricity Directive on "reasonable price".

As per the Electricity Directive, the mandatory de-regulation of the price will be applied at the request of all consumers, except those at a voltage level of 0.4kV. Although not mandatory, all consumers at the level of 0.4kV, including household consumers, will have the opportunity to be supplied electricity by free market suppliers.

According to Order 28/2021, starting from January 2022 it was expected that all voltage levels would be subject to deregulation, except the 0.4kV level.

Other developments

Albania has taken important steps towards the production of renewable energy source ("RES") energy, with two major projects underway. These projects have been approved for the construction of solar power plants and the production of solar energy. Both projects relate to the construction of two solar power plants in the southern and central coastal regions of Albania. In May 2020, the Ministry announced that the winner of the first bid was the French company Voltalia S.A. ("Voltalia"). This project provides for the construction and operation of a 140MW power plant, for which Voltalia and the Ministry signed a 30-year concession agreement on 31 July 2020. Pursuant to the Concession Contract entered into between the parties, Voltalia will sell half of the energy produced to the Electricity Distribution Operator ("OSHEE"), with a price of €24.89 per MWh. The remaining half will be sold to the open market through bilateral energy purchase agreements. Construction works began in June 2021.

The procedure for the second bid was carried out between February and March 2021 and finalised on 25 March 2021. By submitting the lowest bid (€29.89 per MWh), Voltalia was again announced as the winner for this second project.

According to the bidding documents, the project provides for the construction and operation of a 100MW solar power plant. It is expected that 70% of the power generated by this power plant will be sold to OSHEE, and 30% will be sold in the open market through bilateral energy purchase agreements.

A fourth hydropower plant is planned to be constructed upstream of the Drini River. On 6 July 2021, the Albanian Power Corporation ("KESH") and the American Company Bechtel signed an agreement to begin the early works for the 210MW Skavica Plant on the Drini River under a fast-track delivery approach. The Skavica Hydropower Project will be a public investment. Funding sources for the project are still being discussed between the Albanian Government and potential donors.[1]

Furthermore, a 500kWp floating solar plant started operating in April 2022. The project now generates renewable energy for the national grid. The first unit covers nearly 4,000 square meters and has an installed capacity of 500kWp.[2] Finally, Albania is working on an offshore wind project supported by the European Bank for Reconstruction and Development, according to the Ministry of Infrastructure and Energy. The project is in its study phase.

Gas sector

Legal framework

On 22 April 2020, The Albanian Energy Regulatory Authority ("ERE") approved Decision 68/2020 "On the approval of the Code of Natural Gas Transmission Grid". The Code of Natural Gas Transmission Grid has been drafted by Albgaz, pursuant to the provisions of the Law on the Natural Gas Sector, and in accordance with the provisions of the Grid Codes and of the Operational Manual of the European Network of Transmission System Operators for Gas ("ENTSO-G"). The purpose of this Code is to provide a set of open and transparent standard terms and conditions for the transportation of natural gas by companies that are licensed by the ERE. These terms and conditions relate to the trading, supplying, and balancing of natural gas transported through the gas transportation system in Albania.

Entities that wish to operate in the natural gas field, including traders and suppliers, must be registered as a registered party. Only registered parties can enter bidding processes, trade capacity products with other registered parties, and have access to the electronic data and the reservation capacity platforms.

Other developments

It has been announced that the Trans Adriatic Pipeline ("TAP") began operating on 15 November 2020. The gas transportation system crossing Greece, Albania, and the Adriatic Sea began the transportation of gas on 31 December 2020 from Azerbaijan to Italy. In March 2021, it was announced that the first billion cubic meters ("bcm") of natural gas had entered the Greece interconnection point.[3]

Climate change

Legal framework

On 17 December 2020, the Parliament of Albania adopted Law no. 155/2020 "On Climate Change".[4] This legislation entered into force in June 2021. However, the sub-legal provisions implementing the provision of this law have not to date been approved by the CM, with the exception of CMD 830/2021 "On the measures related to providing information on fuel consumption and carbon dioxide ("CO_2") emissions during the marketing of new vehicles". Pursuant to this CMD, this information is made available to consumers to enable them to make an informed choice and promote the purchase or lease of vehicles that use less fuel and, thus, release less CO_2 into the environment.

Scope of the law on climate change

This law provides rules with respect to:

- the general framework of national policy for action on climate change;
- conditions of greenhouse gas ("GHG") emissions from stationary and mobile sources, from products and substances;
- conditions for capture and geological deposition of CO_2;
- the framework of measures for monitoring, reporting and verification of GHG emissions at the level of sectors/ resources and at the national level in accordance with national commitments, domestic and international financing;
- framework for participation in international climate action; and
- establishment of an institutional system for taking action against climate change.

NDC document

Under the Law on Climate Change, the Albanian State is required to declare Nationally Determined Contributions ("NDC"), in order to achieve the global objective of the ("UNFCCC"). The document that includes the NDC action plan must be approved by the CM and must be submitted to the UNFCCC secretariat.

GHG emissions

The law provides also the obligation for a plant operator to monitor its GHG data. When applying for an environmental permit, operators should provide the relevant authority in charge of issuing the permit with the information regarding its GHG data.

New passenger vehicles and new light commercial vehicles are placed on the market only if they comply with the performance requirements of CO_2 emissions, as specified in the decision of the CM. The detailed rules of performance of CO_2 emissions from new passenger vehicles and new light commercial vehicles are provided in CMD 830/2021, as written above.

An operator of a plant that emits CO_2 may choose to mitigate these emissions through various ways of capturing and depositing it. For example, in underground geological formations or through other actions leading to its capture and disposal, according to the requirements set out in the decision of the CM. Rules for the capture and geological disposal of CO_2 or otherwise shall be adopted by the CM, which as specified above, have not yet been approved.

Endnotes

1. See www.kesh.al/en/announcement/the-construction-of-skavica-will-have-a-great-positive-effect.
2. Investment made by Statkraft and Ocean Sun – see www.offshore-energy.biz/albanias-500kwp-floating-solar-plant-restarts-commercial-operation.
3. See www.tap-ag.com/infrastructure-operation/history-timeline#period-12977.
4. As indicated in the framework chapter, this law is partially approximated with the EU ETS Directive and the EU Regulation 525/2013.

Overview of the legal and regulatory framework in Albania

A. Electricity

A.1 Industry structure

Nature of the market

In 2016, Albania adopted the Electricity Market Model (the "Market Model"). The approval of the Market Model was part of the reform undertaken by Albania to reconstruct the electricity sector in accordance with the requirements of Law no. 43/2015 "On the Energy Sector", as amended (the "Law on Energy") and the requirements of the Energy Community Treaty, ratified by Albania in 2006. The need to implement the Market Model has recently increased due to commitment arising from the Berlin Process (Western Balkans 6). The German Government initiated the Berlin Process in 2014 to demonstrate support for the prospect of European integration for the countries of the Western Balkans.[1] The Western Balkans countries met yearly in the same format. Among other things, this resulted in the 2015 Vienna Summit, where the countries reasserted their commitment towards establishing a regional electricity market, and they also agreed to implement measures to remove existing legislative and regulatory barriers and enhance the institutional structures necessary for the functioning of this market in line with the Energy Community Treaty and relevant EU *acquis*.[2]

The Market Model aims to finalise the transition process from the vertically integrated structure of the electricity sector to a separate structure for the supply, production, transmission, and distribution of electricity. The Market Model also strives for more efficient use of the cross-border trade between Albania and its neighbouring countries, as well as the implementation of third-party access in the market and market liberalisation.

In terms of energy production, Albania relies almost entirely on hydropower plants.

Net domestic electricity production in 2021 reached 8,960GWh compared to the 5,310GWh of energy produced in 2020, marking an increase of 70% in production, as a result of the combination of abundant rainfall and the commissioning of new hydropower plants, mainly the Moglica hydropower plant on the Devoll River. During the first trimester of 2022, the net domestic electricity production reached 2,015GWh.[3]

Public hydropower plants represented 58.2% of this production increase; private and concession hydropower plants provided 41.2%, and other renewable energy producers contributed 0.6% of Albania's net domestic electricity production.[4]

Albania has now started to offer incentives for solar and wind projects since Parliament adopted Law no. 7/2017 "On promoting the use of energy from renewable sources" (the "Law on Renewable Sources"). From this, two projects have been approved for the construction of solar power plants to produce solar energy. Both projects relate to the construction of two solar power plants in the southern and central coastal regions of Albania. Furthermore, a 500kWp floating solar plant began operating in April 2022. The project is generating renewable energy for the national grid. The first unit covers nearly 4,000 square meters and has an installed capacity of 500kWp.[5] Finally, Albania is working on an offshore wind project supported by the European Bank for Reconstruction and Development, according to the Ministry of Infrastructure and Energy. The project is currently in its study phase.[6]

Key market players

The public Albanian Energy Corporation (*Korporata Elektro-Energjetike Shqiptare*) ("KESH") is the largest producer of electricity in Albania. KESH manages the main electricity generation plants in the country. These assets consist of the hydropower plants of the Drini Cascade (HPP Fierzë, HPP Koman and HPP Vau i Dejës), which have an installed capacity of 1,350MW, and the TPP Vlora, which has an installed capacity of 98MW.

Under the Energy Law and the Market Model, the Transmission System Operator (*Operatori i Sistemit te Transmetimit*) ("TSO") is the independent state-owned company in charge of the physical operation of the transmission network. The TSO provides the function of the transmission system, which under to the Law on Energy, is defined as the system for the transmission of energy at 'high' and 'very high' voltages connected in parallel with the systems of other countries. The TSO determines the terms for the provision of a connection service to all users of the system in a non-discriminatory manner. The TSO also performs the function of the Balancing Market Operator. Here, the TSO is involved in forecasting and purchasing the ancillary services of all Balanced Service Providers ("BSPs") and performing the necessary actions for balancing and activating secondary adjustments in the reduction (downward) or increase (upward) of balancing reserves.

The Distribution System Operator (*Operatori i Sistemit të Shpërndarjes*) ("DSO" or "OSSH") is responsible for the operation of the distribution network. In accordance with the rules of the Energy Community, the distribution system is separated from the supply system. In this context, the DSO provides the connection service for all users of the system connected to the distribution network, in a non-discriminatory manner. The DSO is also responsible for reducing technical and non-technical losses in the distribution system. The determination of loss reduction is made by international consultants contracted by the DSO and approved by the Energy Regulatory Authority (please refer to the relevant section below). The DSO is currently a state joint stock company with its sole shareholder being the Electricity Distribution Operator, which is also a joint stock company. The Electricity Distribution Operator's sole shareholder is the Ministry of Industry and Energy (*Ministria e Industrisë dhe Energjisë*) ("MIE"). The establishment of OSSH is the result of the legal unbundling of the former Distribution Energy Operator (*Operatori i Shpërndarjes së Energjisë Elektrike*) ("OSHEE") which was split into three licensed subsidiaries, ie a universal service provider ("FSHU"), an electricity supplier ("FTL"), and OSSH.

All legal entities that own production and consumption units connected to the network are above a capacity set by the TSO, and approved by the ERE, must become Balancing Responsible Parties ("BRP"). Any legal entity that owns generation and consumption units connected to the network and under a capacity determined by the TSO and approved by the ERE, can apply to become a BRP. Every trader who trades in Albania or supplies cross-border energy is a BRP and is also a BSP if the trader already provides balancing services.

In a meeting on 15 May 2019, the Council of Ministers of the Republic of Albania ("CM") approved the creation of an Albanian Energy Stock Exchange (*Bursa Shqiptare e Energjisë*) ("AESE" or "ALPEX"). As the most important instrument of this market, the ALPEX will operate and be organised on the electronic platforms of the day-ahead market and the intraday market. This feat was achieved due to the cooperation of the Ministry of Infrastructure and Energy, the Ministry of Finance and Economy, the International Finance Corporation ("IFC"), the Secretariat of the European Energy Community, and local actors in the electricity sector. The company will be established by the TSO and operate the energy exchange. Although the Market Model has foreseen that ALPEX should start operating on 30 June 2017, operations have not yet commenced, even though ERE, with decision dated 29.09.2022, has finally licensed the Albanian Power Exchange (ALPEX). The license has a 5-year term. . ALPEX recently announced that it has launched the open international procedure for the "Electronic Trading Platform for the Day Forward and Intraday Market, Infrastructure and Services Required for the Operation of the Organized Market in Albania and Kosovo".

The MIE aim to draft and implement the general state policy in the industry and energy sector with the utilisation of energy and mineral resources.

Regulatory authorities

The Albanian Electricity Regulatory Authority (*Enti Rregullator i Energjisë Elektrike*) ("ERE") is the regulatory institution of the electricity and gas sector that is run by the board.

Legal framework

Although included in the Law on Energy and in the Market Model, ALPEX and the day-ahead and intraday market, as aforementioned, have not to date been implemented. ALPEX, which is responsible for setting up markets both in Albania and in Kosovo, is currently tendering for a service provider of electronic trading platforms and corresponding services.[7]

Obtaining a licence from the regulator is a pre-condition for performing the following activities:

- power generation;
- operating the transmission system;
- operating the distribution system;
- energy supply;
- electricity trading; and
- operating the electricity market.

Producers with an installed capacity of up to 1MW and self-generators that are not connected to the national grid are not required to obtain a license. As per the legislation of the Republic of Albania, the application for a licence for electricity trading or electricity supply will not be required where a company has a licence issued by a regulatory authority of another country, a contracting party of the Energy Community, a Member State of the European Union ("EU"), or another country with which a bilateral agreement has been signed for the mutual recognition of licenses between the ERE and the relevant regulatory authority.[8]

The validity period of the licenses is determined by the ERE within the following limits:

- energy generation, transmission system operation and distribution system operation up to 30 years; and
- supply, electricity trading, market operation and closed distribution systems up to five years.[9]

Public service obligations ("PSO") may be imposed on licensees. These are determined by the CM.[10]

Through the legislation and the adopted Market Model, Albania aims to fully liberalise the electricity market in order to create a market structure that increases the number of participants, creates the conditions for opening the sector to competition, and increases the participation of foreign investors. The establishment of the ALPEX is a step towards achieving this goal.

Implementation of EU electricity directives

Albania has aligned its legislation with some of the EU directives governing the electricity sector as a part of its bid to join the EU. In this context, the Law on Electricity has been fully aligned with the Third Electricity Directive of the Parliament and of the Council of 13 July 2009.

Alongside the delays with the implementation of the day-ahead and intraday market, the development of competition in the wholesale market has been impeded by the PSO scheme, which involves only state-owned entities. The energy supplier purchases electricity from KESH and the renewable energy producers, and sells it to FSHU for universal supply needs and to OSSH to cover distribution losses. In practice, this amounts to 86% of Albania's total electricity consumption in 2020 which eliminates the possibility for market participants competing for these volumes.[11]

A.2 Third party access regime

Pursuant to the Law on Energy, "third party access" is the right of all users of the system to use the electricity transmission and distribution network. This right is based on defined and published conditions, in accordance with the principles of transparency and non-discrimination, against the approved tariffs set by the ERE.

The TSO and the DSO guarantee network access for all customers and users of the system on a transparent and non-discriminatory basis that is based on tariffs approved and published by the ERE. Producers that produce energy from renewable sources have priority access to the electricity networks. The TSO and the DSO may refuse access to their network if the required capacity is unavailable. The decision to refuse access to the network must be reasoned, based on objective technical and economic conditions, and must consider the obligations of public service and the protection of end customers, as defined by the law. The interested party is notified of the decision to refuse access and where an interested party is denied access to the network, it may request the initiation of a dispute resolution procedure with the ERE.

The national transmission system is connected to the transmission systems of other countries through existing interconnection lines. The TSO, in parallel with the interconnected systems of other countries, functions in accordance with bilateral or multilateral agreements between the operators of the interconnected transmission systems in accordance with the technical requirements, the requirements of safe operation, and other standards for interconnections as defined by the ERE.

A.3 Market design

The objective of the energy market is to create a market based on bilateral transactions and contracts concluded between over the counter ("OTC") market participants or an organised day-ahead and overnight market, as organised through ALPEX. However, the Market Model will only apply when ALPEX is fully implemented.

In terms of unbundling, Albania has made progress and legal unbundling was ensured by the restructuring of the formerly integrated utility OSHEE into a holding of three subsidiaries that are licensed as universal service providers which are FSHU, FTL, and OSSH. Functional unbundling has not to date been completed.

Regarding energy from renewable energy sources ("RES"), the Government of Albania, based on the Law on Renewable Sources, will provide support schemes in accordance with the relevant *acquis* of the Energy Community. These support schemes will be in the form of contracts for difference ("CfD") for independent electricity producers and renewable energy suppliers, to replace their current energy purchase agreements.

A.4 Tariff regulation

The ERE approves and publishes the methodology for calculating distribution transmission tariffs and other applicable methodologies. In particular, the ERE approves tariffs for:

- connections and access to national networks;
- performing balancing services; and
- all licensed activities, for which the PSO has been imposed.

Tariffs are approved *ex ante*, and the duration of the distribution tariff review cycle is three years.

Price de-regulation

Authorities are committed to taking the necessary steps to open the market and de-regulate prices of energy. In this context, the Ministry of Infrastructure and Energy has issued Order 28/2021 "On the approval of the guideline for opening the market and de-regulating prices of electric energy". Pursuant to the findings of the Ministry, 13% of total domestic consumption for 2019 is supplied at unregulated tariffs.

The Energy Law provides for the concept of 'reasonable price', according to which household consumers and small enterprises are supplied with energy at regulated prices. These are categorised as consumers supplied at the level of 0.4kV.[12]

A.5 Market entry

Under the provisions of the Law on Energy, a market participant must be licensed by the ERE according to the activity it intends to perform in Albania. In respect of licensing, a licence must be obtained for each of the activities (see section A.1).

Despite the approval of the Market Model, which provides for the establishment of ALPEX, ALPEX has not started operating. As mentioned above, ALPEX recently announced the launch of the open international procedure for the "Electronic Trading Platform for the Day Forward and Intraday Market, Infrastructure and Services Required for the Operation of the Organized Market in Albania and Kosovo". The process is under development. Consequently, market participant transactions will be based on bilateral negotiations and contracts concluded between market participants.

A.6 Public service obligations and smart metering

Public service obligations (PSOs)

The Law on Energy defines the public service as the service provided by a licensee operating in the electricity sector relating to: the security and quality of supply, regulated prices in the electricity sector, electricity efficiency, energy from renewable sources, the protection of the environment. The fulfilment of the service should not prejudice competition except when it is necessary to provide the public service in question.[13] Public service also includes universal supply service.[14]

The conditions for establishing the PSO are established by the CM.[15] The PSO in the electricity sector is decided taking into account the public interest in exercising this activity. This concerns the conditions in respect of:

- security of supply;
- quality of service;
- tariffs and prices for customers benefit from the PSO;
- environmental protection;
- protection of competition;
- RES;
- energy efficiency;
- any other circumstance that affects the public interest; and
- climate change.

Where a PSO is imposed on a licensee who incurs additional costs that are not included in the tariff set by the ERE, the licensee will be compensated financially or in other forms.[16]

Regarding the universal supply service, the Law on Energy and the implementing decision of the CM establish that universal service is provided only to a certain category of customers (determined by the CM), with a certain quality of supply and at regulated prices. The provisions of the decision of the CM stipulate that a model contract approved by the ERE, must be signed by the universal service provider and the production company charged with the PSO. The model contract establishes the amount of energy provided and the unit price before the beginning of each calendar year of activity.[17] This contract is negotiated annually between the parties. The universal service provider is compensated by the electricity generation company for the amount unsecured by the electricity generation company according to the value specified in the contract.[18]

Provided that the requirement of customers benefiting from the universal supply service is met, the excess quantity of electricity produced under the model contract is sold to the DSO to cover losses. The selling price is based on the average price of the Hungarian stock exchange ("HUPX").[19]

As per the decision of the CM, the universal service provider must provide an uninterrupted electricity supply to state entities that offer public health services, companies that supply drinking water, state institutions for the execution of criminal decisions and state institutions in general.[20]

Smart metering

The implementation of smart metering is in its initial phase, with the pilot project for the installation of smart meters commencing in Tirana. There are currently a few smart meters installed and operating.

Electric vehicles

The data of the Public Directorate of Road Transportation Services shows that during the first quarter of 2022, only 2.7% of cars entered and registered in Albania were electric cars. The demand is still low as Albanian customers are still driven towards less expensive solutions, such as used cars or combustion cars. However, it must be noted that since 2020, no import VAT obligation have applied to new electric cars.

A.7 Cross-border Interconnectors

There are five interconnection lines with neighboring countries (Greece - 400kV, Montenegro - 400kV and 220kV, Kosovo - 400kV and 220kV), with an additional 400kV interconnection line under construction towards North Macedonia expected to be operational from 2023. Thereafter, Albania will be connected with the neighboring countries of Montenegro, Kosovo, North Macedonia, and Greece, with one 400kV line each.[21]

In addition to the new interconnector to North Macedonia, the Albanian TSO is considering constructing a 400kV interconnection to Greece with internal 400kV network reinforcements. However, as this project is at a preliminary stage, no prefeasibility studies have been approved to date.

Based on the current situation of the Albanian legislation, private parties cannot operate interconnectors

B. Oil and gas

B.1 Industry structure

Nature of the market

The oil and gas industry is regulated by Law no. 102/2015 "On the natural gas sector", as amended (the "Law on Natural Gas"), which is fully aligned with the Third Gas Directive[22] and Law no. 7746/1993 "On Hydrocarbons, as amended (the "Law on Hydrocarbons").

Key market players

"Albgaz" Sh.A. ("Albgaz") is a joint stock company with 100% of its shares held solely by the MIE and established by Decision of the CM no. 848, dated 7 December 2016. Albgaz is a combined gas operator. As such, it carries out both the activities of transmission, and distribution of natural gas. In 2017, the ERE granted Albgaz this licence for a period of 30 years. However, to date Albgaz has not commenced any activities.

Albpetrol, is the Albanian upstream hydrocarbons production and marketing company. Its stock is owned by the Albanian state ("Albpetrol").

Regulatory authorities

For a definition of the ERE, see section A.1.

For a definition of the MIE, see section A.1.

The Trans-Adriatic Pipeline ("TAP") is part of the Southern Gas Corridor which transports natural gas to Europe from the Shah Deniz II gas field in Azerbaijan.

Gas sector

In December 2016, the Albanian government separated gas activities from the existing public oil and gas company Albpetrol. This created a new public company called Albgaz which covers the combined functions of the TSO and DSO. According to the Third Gas Directive and Law no. 102/2015 "On the Natural Gas Sector" the TSO will be separated from other activities, including the division in terms of ownership. This means that the newly established company must be separate from the existing company Albpetrol in accordance with the requirements of the new law of the gas sector.

The domestic TSO Albgaz was certified but the conditions in the certification decision have not to date been implemented. Grid Codes are transposed and operationalised by the TAP and Albgaz in separate codes. The implementation of third-party access is performed only by the TAP and in line with the exemption conditions. Despite the lack of a national gas market, secondary legislation that regulates the supply to customers was developed. With the TAP being operational, Albania is formally connected to gas markets. Gas emergency rules are also in place.

Legal framework

The Law on Natural Gas was amended in 2021 to transpose some elements from Regulation (EU) 2017/1938 on the security of supply.

The ERE issues licenses for the following activities:

- natural gas transmission;
- distribution of natural gas;
- natural gas supply;
- natural gas trading;
- operation in natural gas storage facilities;
- operation of LNG plants; and
- operation of the natural gas market operator.

The ERE grants a licence for the transmission of natural gas only to a legal entity for a given territory. An exception is made only in cases where, in a given territory, it is necessary to extend and carry out activities of gas transmission infrastructure which are of strategic and national importance, as determined by the CM. Licensing is completed on the basis of efficiency criteria and economic balance for the system operator. The ERE grants a licence for distribution to only one entity per service territory. Exceptions are only made for cases when it is necessary to extend and carry out activities and other distribution infrastructure of strategic and national importance, as determined by the CM.

Albania has adopted the necessary primary legislation for building a liberalised market. Following, the operation of the TAP, Albania is formally connected to gas market. However, no natural gas market has been established to date.

Implementation of EU gas directives

To date, Albanian legislation concerning natural gas has been approximated with the following directives:

- Regulation (EU) 2017/1938;
- Remit Regulation; and
- The Third Gas Directive.

Building on the regulatory framework of the Law on Natural Gas, the start of the commercial operation of the TAP in late 2020 has been the most important event in the development of Albania's gas market. The TAP, which currently transits gas from Azerbaijan to Italy via Albania, is certified under the independent transmission operator model following an exemption decision and has fulfilled all certification conditions before the operational date. The ongoing construction of exit facilities of the TAP towards a future Albanian network is another milestone for the country's ambition to establish a gas market. Despite this positive momentum, there has been no progress in Albania developing its own gas infrastructure.

Hydrocarbon sector

Albpetrol enjoys the right of first offer, according to which Albpetrol has the right to continue hydrocarbon operations in the areas where third party companies operate. From this, Albpetrol has entered into an agreement to continue hydrocarbon operations in the areas where the third party companies operate. Pursuant to the Law on Hydrocarbons, Albpetrol owns the rights to explore, produce, and trade hydrocarbons.[23]

Albpetrol's right derives from the 'Albpetrol Agreement' which authorises Albpetrol to enter into Hydrocarbon Agreements, by means of which a subject or an entity under the terms and conditions of the Albpetrol Agreement can explore, develop and produce hydrocarbons in the contracted area. Albpetrol may continue its hydrocarbon operations in the area outlined within their contract, should the person or entity fail to fulfill the contractual terms and conditions.[24] In case Albpetrol fail to comply with contractual obligation, as set out in the license agreement ("*licencë marrëveshje*") granted by the ministry in charge of hydrocarbons, the latter may revoke it or take any other appropriate measure provided in the license agreement.

The Albpetrol Agreement allows Albpetrol, for units that have not entered into a hydrocarbon agreement, to market hydrocarbon products for the domestic market or for export in international hydrocarbon exchange.[25]

B.2 Third party access regime to gas transportation networks

In accordance with the conditions set out in the Transmission Grid Code, the TSO will provide unrestricted access to the transmission system. In this regard, the TSO provides its services in a non-discriminatory manner to all network users and provides consistent and uninterrupted services at the entry of third parties. The price of capacity in interruption also reflects the possibility of interruption. The TSO provides the same service to different customers, and it must do so according to the same contractual criteria and conditions. This can be using either harmonised transport contracts and/or in accordance with the Transmission Grid Code approved by the ERE. Transport contracts signed with non-standard start dates or for a shorter duration than a standard annual transport contract will not result in arbitrarily higher or lower tariffs and will not reflect the market value of the service.

The TSO may refuse access to the transmission system when there is a lack of capacity or where access to the system impedes the performance of PSOs as regulated by this law, or in case of great economic and financial difficulties with 'take or pay' contracts that were effective prior to the request for access to the transmission system.[26]

However, the above provisions governing network access will not apply to the TAP. According to the TAP Grid Code, the TAP is exempted from the duty to provide access to third parties for 25 years, beginning from the Commercial Operation Date. This date is set for 31 December 2021.

B.3 LNG terminals and storage facilities

Future storage capacity is expected to increase as in July 2021, the Albanian state gas company, Albgaz, the American Company, Excelerate Energy L.P. (Excelerate), and the Italian company, Snam S.p.A (Snam), signed the Memorandum of Understanding ("MOU") in Tirana. This MOU outlines the possibility of cooperation on the construction of a gas pipeline from the Vlora Terminal in terms of other possible natural gas infrastructures in Albania.

Through this MOU, Albgaz, Excelerate, and Snam will jointly explore solutions that could potentially supply a natural gas storage plant in Albania, thus providing energy security in the region.

A new storage facility is also planned to be constructed in 2028 in south-central Albania.

B.4 Tariff regulation

The ERE approves the methodology and sets the tariffs for access to the transmission and distribution network, the tariffs for connection to the transmission or distribution network, the tariffs for access to storage facilities and LNG plants, and the supply tariffs for end customers supplied to on the basis of the PSO.

The prices of wholesale gas activities between suppliers and the prices of retail activities between suppliers and customers are determined by supply and demand.

The provisions of the Law on Natural Gas and the Gas Directive regarding tariffs do not apply to the TAP. According to the TAP Grid Code, the latter is exempt from the application of regulated tariffs.[27]

B.5 Cross-border interconnectors

The TAP is the only operational cross border interconnection. However, there are other projects for building interconnectors with neighbouring countries. For example, the ALGOKAP between Albania and Kosovo (commissioning planned for 2027), the Ionian Adriatic Pipeline between Croatia, Montenegro, Bosnia-Herzegovina, and Albania which plans to connect the existing Croatian gas transmission system via Montenegro and Albania with the TAP system (commissioning planned for 2025).

In July 2021, the Albanian Ministry of Infrastructure and the Albanian gas company Albgaz signed an agreement with the TAP to build a new facility that enables an interconnection point between the TAP gas transportation system and future gas infrastructure in Albania.[28] The gas exit point in Fier (south-central Albania) will have expandable capacity and the possibility for bidirectional flow.

C. Energy trading

C.1 Electricity trading

The trading of physical bilateral contracts is permitted only in conformity with the purchased and nominated capacities in the open auction organised at Coordinated Auction Office in South-East Europe ("SEE CAO"). The contracting parties and the quantities and prices from the negotiations is confidential information. As far as the provisions of the Market Rules, the Grid Code and other relevant regulations require that such information is declared to the TSO in the time frame for the day ahead, and is nominated for all concluded agreements for the day-ahead organised market.

All OTC markets are based on the financial contracts, where the physical energy is traded by the Power Exchange and the Exchange is the referring price for the financial contracts. The ERE establishes a standard agreement for OTC financial contracts.

In 2022 it is expected that the power exchange will be fully implemented in Albania. Bilateral electricity trading contracts that reflect the prevailing state of affairs are expected to be part of the organised electricity market. ALPEX will be the central party for energy providers and buyers in the market, performing the function of a clearing house of all obligations that will arise from energy exchange auctions. The CfD is a financial mechanism that will promote stock exchange trading. This is clearly defined in the Market Model and will be used as an interim measure which allows the movement of volumes from bilateral contractual agreements in ALPEX.

C.2 Gas trading

No trading activities have commenced to date.

D. Nuclear energy

This aspect is not relevant at this time.

E. Upstream

For a description of the upstream regime, see section B.1.

There are two Hydrocarbon Agreements (or Production Sharing Contracts) concerning the exploration, development and production on hydrocarbons in the oil and gas exploration blocks in Albania:

- Agreement on Block 2-3, onshore, with the company Shell Upstream Albania; and
- Agreement on Block 4, onshore, also with Shell Upstream Albania.

Three Hydrocarbon Agreements are almost being concluded:

- Agreement on Block Joni-5, offshore with Capricorn Albania (Cairn Energy);
- Agreement on Blocks 2, 3 and 4, offshore with Emanuelle Adriatic Energy Limited; and
- Agreement on Durrës Block, offshore.[29]

F. Renewable energy

F.1 Renewable energy

The 2017 Law on Renewable Sources is partially approximated with the Renewable Energy Directive.

Law no. 7/2017 provides different mechanisms of support, depending on installed capacities. For capacitities below 2MW, the support consists in purchasing electricity produced by priority producers at a price determined through the methodology approved by the CM, which is based on a reasonable return on the value of the investment according to the type and technology of the capacity used. For capacities above 2MW, Law no. 7/2017 provides a support mechanism based on the principle of margin contract or CfD. Such support is granted to the subject which has been declared winner in the competitive bidding process of granting support.

F.2 Renewable pre-qualifications

The Ministry of Infrastructure and Energy, by means of Qualification Request Documents, invites Potential Bidders to prepare and submit an Application for Qualification as part of the Qualification Procedure, in relation to Projects. This Request for Qualification is the first stage of a two-stage procedure, to be followed by a subsequent stage of Request for Proposal documentation.

Qualification Documents constitute an invitation to submit an Application for Qualification. They do not constitute a request for investment or participation in the Projects.

F.3 Biofuel

Albania has set a mandatory target for 38% of its gross final energy consumption to be met by RES by 2020 and an objective of 45% for 2030.[30] However, this remains an objective on paper as Albania has not yet adopted a law on biofuels that would sanction this objective.

G. Climate change and sustainability

G.1 Climate change initiatives

In the context of the United Nations Framework Convention on Climate Change ("UNFCCC"), Albania has started the process of changing its status from a developing country to a developed country. This process is an integral part of the EU integration process and includes capacity development at the national level for annual greenhouse gas ("GHG") monitoring and reporting. The process also includes the formulation and implementation of policies to reduce GHG, the adaptation to climate change transposition, and the implementation of EU climate change legislation. In line with EU targets, Albania has set quantitative targets in relation to energy efficiency (according to the respective target of 6.8% set in 2020) and RES (according to the respective target of 38% set in 2020 which is awaiting implementation) within the framework of the Energy Community Treaty. These objectives have already been established in the Second and Third National Energy Efficiency Action Plans approved by the CM.

Albania has adopted Law no. 155/2020 "On Climate Change" which provides Albania's Nationally Determined Contributions ("NDC").[31] An NDC is the national contribution to the reduction of GHGs against the achievement of the global objective of the UNFCCC to keep global warming below 2°C.[32] The NDC is subject to revision every four years and, if possible, updated with the aim of increasing the GHG reduction target to the extent permitted by country conditions.

G.2 Emission trading

This aspect is not relevant at this time.

G.3 Carbon pricing

This aspect is not relevant at this time.

G.4 Capacity markets

This aspect is not relevant at this time.

H. Energy transition

H.1 Overview

Energy balance in Albania is dominated by fossil fuels – mainly crude oil – whose ratio has ranged between 46% and 68% over the las five years. Hydropower is the second largest contributor. Law 7/2017 sets out the adoption of the National Renewable Energy Action Plan (NREAP), which, among others, provides targets for the share of renewable energy in the total energy consumption of the country, including electricity, transport, heating and cooling. The NREAP provides for an overall target of 45% for the renewable energy share of final energy consumption by 2030.[33]

H.2 Renewable fuels

Hydrogen

This aspect is not relevant at this time.

Ammonia

This aspect is not relevant at this time.

H.3 Carbon capture and storage

The operator of a carbon dioxide (CO_2) emitting plant may choose to mitigate these emissions through various ways of capturing and depositing it. For example, in underground geological formations or through other actions leading to this result, according to the requirements set out in the decision of the CM.

It is the responsibility of the CM to adopt rules for the capture and geological disposal of CO_2.[34]

H.4 Oil and gas platform electrification

This aspect is not relevant at this time

H.5 Industrial hubs

This aspect is not relevant at this time.

H.6 Smart cities

This aspect is not relevant at this time.

I. Environmental, social and governance (ESG)

This aspect is not relevant at this time.

Endnotes

1. Albania, Bosnia & Hercegovina, Kosovo, Montenegro, North Macedonia, Serbia.
2. See www.energy-community.org/regionalinitiatives/energy/WB6.html.
3. See www.instat.gov.al/media/10022/bilanci-i-energjis%C3%AB-elektrike-tr-i-2022.pdf.
4. See www.instat.gov.al/al/temat/mjedisi-dhe-energjia/energjia/publikimet/2020/bilanci-i-energjis%C3%AB-elektrike-2020.
5. Investment made by Stat and Ocean Sun – see www.offshore-energy.biz/albanias-500kwp-floating-solar-plant-restarts-commercial-operation.
6. See euronews.al/vendi/aktualitet/2022/06/15/shqiperia-do-te-prodhoje-energji-elektrike-nga-era-thote-balluku.
7. The Annual Implementation Report of November 2021 of the Energy Community, p.5.
8. Article 4(3) of Regulation 215/2019 of the ERE, with respect to the procedure and terms for granting, modifying, transferring, renewing, or revoking of license in the Energy Sector.
9. Id., article 5.
10. CMD 244/2016 'On the approval of conditions for the Public Service Obligations to be applied to licensed subjects in the Energy Sector'.
11. According to Annual Implementation Report of November 2021 of the Energy Community, p.4.
12. Order of MIE 28/2021 'On the approval of the guidelines for opening the market and de-regulating the price of electric energy'.
13. Article 3(75) Law on Energy.
14. Id., article 3(76).
15. CMD 244/2016, conf. supra.
16. Id, point I(5).
17. Id., II(2).
18. Id.
19. Id. II(4).
20. Id. (II)4.2.
21. Energy Community Secretariat, February 2021, 'Electricity Interconnection Targets in the Energy Community Contracting Parties'.
22. The Third Gas Directive of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in natural gas and repealing the Second Gas Directive.
23. Article 2(1) Law on Hydrocarbons.
24. Id., article 12.
25. Article 12(ç) Law on Hydrocarbons.
26. Decision 97 dated 16.5.2020 of ERE 'On the approval of the TAP Grid Code'.
27. Pursuant to article 32 of the Law on Natural Gas and articles 41.6, 41.8 and 41.10 of Gas Directive.
28. See www.tap-ag.com/news/news-stories/tap-to-deliver-the-first-gas-exit-point-in-fier-albania.
29. See www.akbn.gov.al/information-on-the-actual-state-of-hydrocarbon-agreements/?lang=en.
30. CMD 580/2019, "On the approval of the national consolidated action plan for renewable energy sources, 2019-2020.
31. Partially approximated with Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003, establishing a scheme for GHG emission allowance trading within the Community and amending Council Directive 96/61/EC and EU Regulation 525/2013 of the European Parliament and of the Council of 21 May 2013 on a mechanism for monitoring and reporting GHG emissions and for reporting other information at national and Union level relevant to climate change and repealing Decision 280/2004/EC.
32. Article 7(1) Law on Climate Change.
33. CMD 580/2019 "On the approval of the national consolidated action plan for renewable energy sources, 2019-2020.
34. Article 19 of Law on Climate Change

Energy law in Austria

Recent developments in the Austrian energy market

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Renewable energy expansion act

The Clean Energy Package ("CEP") provides the legal framework for the Austrian Renewable Energy Expansion Act (*Erneuerbaren-Ausbau-Gesetz*) ("EAG"). Under this act, the national reference values for renewable energy comply with the measures set out under the CEP. The EAG regulates the conditions for promoting the production of electricity, gas, and hydrogen from renewable sources.

From 2030 onwards, Austria aims to cover 100% of its total electricity consumption from renewable energy sources. To achieve this target, the annual generation of electricity from renewable sources is planned to be increased and the share of nationally produced renewable gas is also to be increased.

Paradigm shift: market premium instead of feed-in tariffs

The Green Electricity Act (*Ökostromgesetz 2012*) ("ÖSG 2012"), which is now superseded by the EAG, provided for feed-in tariffs ("FiTs") based on a contract with the Green Electricity Settlement Agency ("OeMAG"). FiTs for renewable energy were determined on the basis of the Green Electricity Feed-in Tariff Ordinance (*ÖSET-VO 2018*). These FiTs were usually higher than the market price for electricity and were intended to compensate for higher production costs and the OeMAG was obliged to purchase the electricity. In contrast, the EAG focuses on market premiums and self-marketing.

The aim of the market premium is to compensate for the difference between the production costs of renewable energy and the average market price. Market premiums are granted either competitively within the framework of tenders (photovoltaic ("PV") and biomass) or administratively upon application (wind power, hydropower, small biomass plants, and biogas plants). The first come first serve principle applies to the administrative market premium. The values will be set for each calendar year by decree of the Federal Minister for Climate Protection, the Environment, Energy, Mobility, Innovation, and Technology in consultation with other Federal Ministries.

The market premium is calculated on the basis of the difference between the value to be applied (*anzulegender Wert*), which is determined either by tender or by decree, and the reference market value, which is the average value of the day-ahead market.

In addition to market premiums, the EAG foresees investment grants for PV plants, electricity storage facilities, hydropower plants, and wind power plants.

Purchase obligation of electricity traders

The EAG replaces the previously guaranteed purchase of green electricity by OeMAG through direct marketing. However, small plant operators (less than 500kW) are exempt from the obligation to market their electricity themselves.

As a safety mechanism, once three electricity traders have rejected an off-take contract for electricity from a plant subsidised under the EAG on market terms, an electricity trader will be assigned by the balancing group coordinator. The electricity trader assigned to the system operator must conclude an off-take contract for the system in question at the reference market price.

Renewable energy communities (EEG)

The EEG was implemented as a new player on the Austrian energy market.

An EEG may generate energy from renewable sources, consume the self-generated energy, store, or sell it. It may also bundle several customer loads of generated electricity for purchase, sale, or auction (aggregation). EEGs can also own and operate their own distribution network.

Members of an EEG can be natural persons, municipalities, and small and medium-sized enterprises. While special provisions allow wind farms, hydropower, or larger PV projects to participate in EEGs, generation companies controlled by a utility, supplier, or electricity trader, as defined in the Electricity Industry and Organisation Act 2010 (*Elektrizitätswirtschafts-und –organisationsgesetz 2010*) ("ElWOG 2010"), are not permitted to participate in the EEG. The main purpose of the EEG is not for profit.

As the members of the EEG must be located in the same area, consumers must be connected to the generating plant locally via middle or low-voltage distribution grid (ie, at grid levels 5 to 7) within the concession area of one grid operator. As a rule, cross-regional consumption, and the transport of self-generated energy via grid levels 1 to 4 is not permitted. Therefore, transmission from one network operator area to another is not possible. Furthermore, regional joint exchange is promoted by a reduced grid usage fee, as well as an exemption from the renewable energy subsidy and the electricity levy.

New grid reserve regime

Grid reserves are regulated under the ElWOG 2010.

Grid reserves are power capacities that can be called up to eliminate grid bottlenecks and therefore ensure that the amount of capacity held in reserve corresponds to the identified demand. This also ensures that a sufficiently large capacity reserve is available at all times for congestion management. Grid reserves contribute to grid stability and security of supply in the promotion of volatile renewable energy generation. The new grid reserve regime basically provides for grid reserves as the last resort for the elimination of congestion since it shall only be enacted if other congestion management measures are not sufficient.

The need for grid reserves is determined on the basis of the results of a system analysis, which has to be carried out annually by the control area manager. The selection decision regarding the electricity supplier is carried out by the control area manager in a two-stage process based on eligibility criteria set by the control area manager and agreed with E-Control, the Austrian regulatory authority responsible for energy market regulation on an administrative level. The selection decision must be approved by E-Control.

Further development of the balancing model in the gas sector

E-Control aims to establish an integrated balancing scheme for the entire market area without systematic separation between the transmission level and distribution area, whereby the contractual and operational complexity is reduced. This replaces the previous separation into "*ex-ante*" and "*ex-post*" accounting. The final concept of the integrated balancing scheme will take place within the framework of the new Gas Market Model Ordinance 2020 (*Gas-Marktmodell-Verordnung 2020*) (GMMO-VO 2020), which was postponed to 1 April 2022 due to the Covid-19 pandemic. It was finally enacted on 1 October 2022.

Overview of the legal and regulatory framework in Austria

A. Electricity

A.1 Industry structure

General

The Austrian energy market is divided into several participants: energy generators, Transmission System Operators ("TSOs"), Distribution System Operators ("DSOs"), and suppliers. Austria has implemented the 'balance group model', which is a virtual group of suppliers and customers within which energy production and supply is balanced. While each market participant must be a member of a balance group, energy suppliers and traders may decide whether they join an existing balance group or initiate their own group.

Nature of the market

As a result of European electricity law, the Austrian electricity market has been fully liberalised since 1 October 2001. Before 2001, the electricity sector reflected Austrian post-war policy; public utilities acted on the Austrian market and prices were regulated by the state. Since its liberalisation, the electricity industry has been characterised by the coordination of a number of market players.

Key market players

The market players include market area managers, clearing and settlement agents, TSOs, balancing group representatives, DSOs, suppliers, generators, electricity wholesalers, retailers, and traders.

The major electricity generators are Verbund, EVN, and Wien Energie.

Before 2011, there were three market areas within Austria operated by different TSOs. However, since 2011 Austrian Power Grid (APG) operates 95% of the Austrian transmission system. The remaining transmission system in the provincial state of Vorarlberg is operated by Vorarlberger Übertragungsnetz GmbH.

There are over 130 electricity distributors in Austria, among which are Wiener Netz GmbH, TINETZ-Stromnetz Tirol AG, Netz Oberösterreich GmbH, EVN Netz GmbH, Bewag Netz GmbH, and KNG Kärnten Netz GmbH.

Regulatory authorities

Market supervision in the energy sector is the sole responsibility of the regulator, E-Control GmbH. This means that E-Control is responsible for establishing market rules for competition and regulating network tariffs. If market rules or the overall rules governing competition are breached, E-Control can intervene by means of ex post regulation, identifying and putting an end to any infringements. E-Control must cooperate with other relevant authorities, in particular the Federal Competition Authority (*Bundeswettbewerbsbehörde*) and the Federal Cartel Prosecutor (*Bundeskartellanwalt*), where necessary.

Internally, E-Control consists of three decision-making bodies, which are the: Board of Directors, Regulatory Commission, and Supervisory Board. Decisions on refusal of network access or storage access and the arbitration of disputes between network access holders and network operators have been delegated to the Regulatory Commission.

In addition to E-Control, the Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology (the highest administrative authority at federal level) and various other administrative authorities, such as the state governments, play a role in regulating the electricity sector.

Legal framework

Under the Austrian federal system, the responsibility for regulating the electricity market is divided between the legislator of the federal state (*Bund*) and the provincial states (*Länder*). The ElWOG 2010 provides common principles for the electricity market on the basis of which the Electricity Acts of the nine Austrian Provinces ("Electricity Acts") provide detailed regulations on electricity matters.

In addition to the rules of the ElWOG 2010 and the provincial Electricity Acts, the functioning of the electricity market is regulated by a combination of legal and contractual rules and regulations ensuring the successful operation of the market by allocating responsibilities to the respective market players and the system operators ("Market Rules"). Together with technical and organisational rules ("TOR"), and other market rules, the Market Rules determine the general terms and conditions of DSOs and TSOs, balancing group representatives, green power balancing group representatives, and clearing and settlement agents.

A.2 Third party access regime

Network connection

System operators must publish general terms and conditions ("GTCs") and conclude agreements under the GTCs with end users and generators, providing for their connection to the grid. Grid users have a corresponding right and obligation to connect their facility to the DSO operating in their respective service territory. Customers cannot choose from which grid operator they receive their connection, and the grid operator has a supply and connection obligation within its concession area. Customers can however choose their energy supplier.

The GTCs for grid access must not be discriminatory, must not include abusive practice, unjustified restrictions or endanger the security of supply or quality of service. The GTCs are subject to approval by E-Control.

The grid connection itself is planned with equal treatment of all grid users.

The Electricity Acts set out conditions under which the DSO may refuse grid connection. These exceptions to the general obligation include cases where connection to the grid would not be economical in the interests of all system users. Additionally, grid access may be denied if the grid user requires or wants to feed in electricity at a voltage higher than 110kV. In this case it is the TSO who must grant access to the transmission grid.

The key obligations are provided in the GTCs of the system operator. Generally, there is no obligation on parties to pay in advance or provide collateral (cash deposit, bank guarantee, deposit of savings books) for grid connection. However, the DSO may request collateral in an appropriate amount, if the circumstances of the individual case so warrant, ie, if there is reason to believe that the system user will fail to meet their financial obligations.

Generally, a generation plant must be connected to the existing public distribution grid to have generated energy purchased and paid for by electricity suppliers or traders. The producer has an off-take contract with a supplier and a purchase contract with the same or another supplier.

Disputes or complaints may be submitted to E-Control for determination.

A.3 Market design

The Austrian electricity market is an 'energy only market' and therefore remunerates only the energy 'actually generated'. Austria currently does not intend to change this model.

The control area manager, APG, is responsible for power-frequency control within the control area. The quantities of controlled energy and the costs of the control reserve are forwarded from the control area manager to the balance group coordinator, APCS Power Clearing and Settlement AG, who acts as a clearing house for both the control reserve and the balancing energy. The balance group combines metering points and traders into a virtual group to enable a balance between supply and demand and therefore enable consumers, generators, suppliers, and wholesalers to trade or conclude deals with each other. Whoever takes electricity off the grid, feeds in or trades must be a member of a balance group.

A.4 Tariff regulation

Transmission and distribution grids are subject to regulatory intervention through fixed system-use tariffs. The tariffs are set by the Regulatory Commission (E-Control) via administrative decision and can be found in the System Usage Charge Ordinance (*Systemnutzungsentgelte-Verordnung*). Tariffs are paid by consumers per metering point, depending on the grid level and location. The ordinance differentiates between summer and winter, and high and low tariff periods, and is based on network costs and quantity structure, which are both determined through an administrative decision of E-Control.

System operators have the right to appeal against a tariff decision of E-Control.

A.5 Market entry

Authorisations

An authorisation from E-Control is required for TSOs or DSOs, which must be granted if certain licence conditions are fulfilled. Electricity traders and suppliers must submit a notification of activity to the provincial governments of the respective provinces in which they carry out the activity.

To be able to operate as an electricity trader or supplier in Austria, membership in a balance group is a prerequisite. This is done by either (i) establishing an own balancing group or (ii) joining an existing balancing group.

Electricity wholesale traders must apply for a trading licence from E-Control. Electricity traders who supply final customers must notify their business activity in accordance with the Electricity Acts of the relevant provinces.

Suppliers must draw up GTCs for the supply of electrical energy for customers whose consumption is not measured via a load profile meter. The GTCs of supply and any amendments must be notified by the regulatory authority prior to their entry into force and published in an appropriate form. The GTCs and any amendments are subject to E-Control approval. The annual electricity invoice of traders and other suppliers supplying end consumers must disclose the shares of all primary energy carriers in the energy source mix that the trader used in the preceding year.

Licensing regime

Under the provincial Energy Acts, the construction and operation of a generating facility that exceeds a certain capacity (usually 20kW) generally requires an electricity permit issued by the relevant provincial authority. In addition, permits under forestry law, nature protection law, construction law and/or water law may be required. Plants with certain technology and size are subject to an Environmental Impact Assessment ("EIA") approval in accordance with the Environmental Impact Assessment Act (*Umweltverträglichkeitsprüfungsgesetz*) ("UVP-G 2000"). The UVP-G 2000 provides for a 'one-stop shop' approval procedure.

In accordance with the provisions of the Third Energy Package, a TSO must obtain certification by a legal notice from E-Control (other concessions and licences are not required). A concession is needed for the operation of a distribution system. The Electricity Acts provide for detailed regulations concerning the requirements for acquiring such a concession. As a minimum requirement, concession applicants who have more than 100,000 customers connected to their grid and who are part of a vertically integrated company must be independent from the other spheres of activity not related to distribution, at least in their legal form, organisation, and decision-making power.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The ElWOG 2010 and the Electricity Acts call for high quality electricity to be provided to the Austrian people and industry at reasonable prices, and for the security of supply to be maintained. To this end, grid operators should ensure non-discriminatory treatment for all grid customers, conclude private-law agreements with grid users providing for their connection to the grid (in line with the general obligation to connect), and set up and maintain a grid infrastructure adequate for domestic electricity supply.

Electrical service providers must also take measures to eliminate grid bottlenecks and ensure security of supply.

Traders and other suppliers who provide household customers with electricity must act as a 'supplier of last resort'. The companies concerned must supply household customers and small-scale enterprises on request, on the basis of their relevant GTCs and a general tariff, which must be published by the relevant company.

Smart metering

Under section 81a of ElWOG 2010, system operators must equip end-users with an annual electricity consumption of less than 100GWh with intelligent metering systems. By the end of 2022, at least 95% of the end consumers connected to the grid of a grid operator will be equipped with smart meters.

Electric vehicles

In Austria, electric vehicles ("EVs") are defined by the road traffic regulation (*Straßenverkehrsordnung*) ("StVO") and the Motor Vehicle Law (*Kraftfahrzeuggesetz*) as vehicles powered solely by battery electricity ("BEV") and plug-in hybrids.

With regard to the charging infrastructure for EVs, several European and national initiatives are establishing publicly accessible charging points.

A significant increase in new registrations of EVs has been seen due to the amendment of company car taxation with effect from 1 January 2016. BEVs are entitled to a tax reduction under the Value Added Tax Act (*Umsatzsteuergesetz*) (section 12 para. 2 no. 2a) and are exempt from the motor-related insurance tax under the Insurance Tax Act (*Versicherungssteuergesetz*) (section 4 para. 3 no. 6) and the motor vehicle tax under the Motor Vehicle Tax Law (*Kraftfahrzeugsteuergesetz*) (section 2 para 1. No. 9). An exemption also exists with regard to the standard consumption tax (*Normverbraucherabgabengesetz* – NoVa). Vehicles with a carbon dioxide ("CO_2") output of less than 90g/km are exempt from the standard consumption tax, which means all solely electrically powered vehicles and a large proportion of hybrid vehicles are exempt.

By the end of April 2021, 9,024 fully electric EVs were newly registered in Austria. This is an increase of 202.3% compared to April 2020, meaning that 10.5% of all new registrations are EVs. From January to December 2021, 33,366 EVs were newly registered in Austria. In 2022, 30,194 e-cars were newly registered, resulting in about 106,502 purely electrically powered passenger cars by the end of November 2022. There are around 13,800 public charging points in Austria.

A.7 Cross-border interconnectors

Austria has a strongly integrated wholesale market and therefore has interconnections with all neighbouring countries (ie, the Czech Republic, Hungary, Italy, Germany, Slovenia, and Switzerland), except for Liechtenstein and Slovakia.

Congestion in the transmission system exists with the Czech Republic, Hungary, Slovenia, Italy, and Switzerland, and is managed partly in the form of implicit auctions within the framework of European day-ahead market coupling and partly by means of explicit auctions (remaining congested borders). In addition to the explicit allocation method, transmission rights are allocated implicitly for the day-ahead time period at the borders with Germany, Italy, and Slovenia.

The transmission capacities available for the market at each cross-border interconnection point were generally determined bilaterally between the TSOs involved using the 'NTC method', which is based on the principle that the maximum exchange of energy between adjacent bidding zones is *ex ante* checked and determined.

The interconnection capacity in the main directions of trade flows on the Czech and Hungarian borders has been expanded in the past few years, and the interconnectors between Germany and Austria have been further developed. At the other borders, interconnection capacity has generally remained unchanged.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Oil is considered a federal state-owned mineral resource that is in the possession of the Austrian Federal State pursuant to the Mineral Resources Act ("MinroG") (section 1 no. 10). Therefore, the Federal State has the right to search, explore, and produce oil and natural gas. The Federal State is authorised to transfer the exercise of these rights to individuals or legal entities, and to groups of persons, based on commercial law, that have the necessary technical and financial means for the establishment and operation of such mining activities (section 69 para 1 MinroG). Such contracts are concluded by the Federal Minister for Economic Affairs in consultation with the Federal Minister of Finance.

Key market players

The companies engaged in the exploration and production of oil in Austria are OMV, RAG Austria AG ("RAG"), and ADX Energy. The only oil refinery in Austria is located in Schwechat and is operated by OMV. OMW supplies about 88% of domestic oil consumption. Austria is considered a transit country for crude oil with two main oil pipelines crossing Austrian territory. Oil is transported from the Port of Trieste to Austria through the Trans-Alpine Pipeline (*Transalpine Ölleitung*). Close to the Italian-Austrian border, the Adriatic Sea-Vienna pipeline (*Adria-Wien Pipeline*) branches off and pumps imported crude oil directly to the refinery in Schwechat.

Regulatory authorities

On an administrative level, the competent authority is the Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology. The competent authority for the exclusive above-ground extraction and processing of basic mineral raw materials is the district administrative authority, unless otherwise expressly stipulated (eg, responsibility of the state governor for an above-ground extraction project crossing the district borders). The duties of the authorities include, among other things, the ordering of safety measures if persons, objects, or the environment are endangered by mining activities.

Legal framework

The exploration and production of oil is regulated by the federal legislator in the MinroG. This act applies to the whole of Austria and not only regulates the exploration and production of oil and natural gas, but also the search and exploration of geological structures that can be used as storage facilities.

Gas

Nature of the market

The Austrian natural gas market has been fully liberalised since 1 October 2002. Austria is dependent on the import of natural gas, mainly from Russia, Norway, and Germany.

By January 2013, a new gas market model was introduced through which the national and transit pipeline systems were merged into three market areas, ie East Austria, Tyrol, and Vorarlberg. The market areas are managed by the market area manager (*Marktgebietmanager*), which is designated by the TSOs active in the respective market area. The TSOs responsibilities include non-discriminatory access, coordination, administration, and balancing of accounts of the respective market area.

The Central European Gas Hub ("CEGH") in Baumgarten has been one of the most important settlement centres for natural gas in Europe and is now operated as a virtual trading point ("VTP") with only one entry/exit zone.

The unbundling rules are similar to those for the electricity market (see section A.1).

Key market players

Gas Connect Austria ("GCA") and Trans-Austria-Gasleitung GmbH ("TAG") are the two operators of the transportation pipeline systems in Austria. Since 1 September 2014, GCA continues the business of Baumgarten-Oberkappel Gas Transmission Corporation.

In addition, there are about 20 DSOs distributing natural gas. These include GCA, EVN Netz GmbH, Gasnetz Steiermark GmbH, Oberösterreichische Ferngas AG and BEGAS – Burgenländische Erdgasversorungs-AG.

Regulatory authorities

On an administrative level, E-Control is also responsible for the regulation of the gas market (for the competences of E-Control see section A.1). The competences of other authorities responsible for competition matters remain with the Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology as the highest authority. The Federal Minister is also responsible for the regulation of the search, exploration, and production of natural gas. Additionally, the Federal Minister is authorised to transfer the exercise of the right to search, explore, and produce natural gas to individuals, legal entities, and groups of persons based on commercial law by civil contract.

Legal framework

The regulatory framework for the natural gas market is governed by the Austrian Gas Act (*Gaswirtschaftsgesetz 2011*) ("GWG"), while the search, exploration, and production of natural gas is regulated by the MinroG.

Implementation of EU gas directives

The Third Gas Directive was implemented in the GWG whereby, among other things, the provisions for the introduction of the entry/exit-system and comprehensive unbundling rules have been implemented.

B.2 Third party access regime to gas transportation networks

The TSO must grant non-discriminatory access to entitled parties under the GTC. Access to the transportation network is mainly affected by booking capacity at the transportation network's entry/exit points.

Entry capacity rights entitle the holder to inject gas into the transportation network and to transport it to the VTP, whereas exit capacity rights entitle the holder to transport gas from the VTP to the exit point and to withdraw it from the transportation network. The second main part of the GWG provides for detailed rules on network access, including rules on capacity calculation and capacity allocation. The recently enacted Gas Market Model Regulation 2020 additionally foresees in-depth rules on these topics.

Access can be refused under certain conditions, for example in the case of extraordinary system conditions, insufficient system capacity or insufficient interconnections of systems. If the right of access is not granted, the party seeking access can bring an appeal before the regulatory commission of E-Control.

In case of insufficient system capacity or insufficient interconnection, access is granted in accordance with the following, provided that the capacity is duly notified:

- transport is regulated under the terms of the existing contracts and of the contractual obligations superseding such contracts, if this is in accordance with the competition rules;
- applications to use additional capacities must be considered in chronological order. However, transport to final customers within a market area has priority over other transport; and
- priority transport is to be granted to supply customers who must perform service obligations.

Committed transport capacities that are not used will be made accessible to third parties. If no notice of the required capacity is given, or if it is not given in due time, the respective party's right of access will be subject to available capacity.

The party entitled to system access can apply for the system to be expanded in the event of refusal of access due to insufficient system capacity or insufficient interconnection of systems for transports within a market area. The requested capacity will be taken into consideration in long-term planning by the market area manager.

Distribution companies must enter into private law contracts with consumers regarding connection to the natural gas distribution system and system utilisation under authorised GTCs within their distribution area.

Transportation and distribution pipelines are subject to regulatory intervention through fixed system-use tariffs. All charges are fixed by the Gas System Charges Ordinance 2013 (*Gas-Systemnutzungsentgelte-Verordnung*) except for the supplementary service charges.

B.3 LNG terminals and storage facilities

The storage of natural gas is carried out by RAG and GCA. Natural gas is stored in hydrocarbon-bearing geological structures.

Storage companies must grant access to storage facilities to producers, natural gas traders and suppliers domiciled in the EU under non-discriminatory and transparent conditions. The storage company must stipulate storage utilisation charges on a non-discriminatory basis. The principles on which the storage charges are calculated must be published once a year and whenever there is a change, access to storage can be refused under certain conditions, for example if access is economically unreasonable, in the event of incidents or in the event of a lack of storage capacity.

The party seeking access to storage can file an application with the regulatory authority if access to storage is refused. The regulatory authority must decide within one month of an application to the authority whether the prerequisites for refusal of access apply. If the authority finds that the right to storage access has been violated, access must be granted immediately upon receipt of that decision.

The Austrian gas market is currently not linked with liquefied natural gas ("LNG") terminals outside Austria. The import of LNG gas is nonetheless an option, as some Austrian companies plan to construct new LNG infrastructure in the Adriatic region and to build, or expand, the necessary transport capacity. Currently only one LNG plant is operated in Austria, which is considered a pilot project of RAG.

B.4 Tariff regulation

Transmission and distribution grids are subject to regulatory intervention through fixed system-use tariffs. Tariffs for gas TSOs and DSOs are regulated in the Gas System Charges Ordinance 2013 (*Gas-Systemnutzungsentgelte-Verordnung 2013*). Tariffs for TSOs are based on a methodology and tariffs for DSOs are based on cost decisions. If requested by E-Control, the methodology must be adjusted or redesigned. Tariffs resulting from the application of the approved methodology are enacted by an ordinance of the regulatory authority and are published on the internet by the individual network operators.

In January 2017, a new methodology for the calculation of system tariffs for gas was introduced, under which the costs to be borne between the entry and exit points are based on the capacity-weighted distance (entry/exit split). The entry/exit split builds the basis for the calculation system. Fee groups are then formed (equalisation) in order to enable foreseeability and calculability of fees for grid customers of the transmission system.

B.5 Market entry

An authorisation from E-Control is required for the performance of an activity as a TSO or DSO. This authorisation must be granted if certain licence conditions are fulfilled.

Natural gas traders buying or selling natural gas for customers in Austria must notify their activities to E-Control prior to commencement. Additionally, independent natural gas traders (applicants) must register as balance group representatives (*Bilangruppenverantwortliche*) and establish a balance group in at least one of three Austrian market areas (instead of registering as balance group representative they may join an existing balance group). It is therefore necessary to conclude a contract with the clearing and settlement centre and the market area manager. No physical presence is required to trade natural gas in Austria. However, a process agent must be appointed and notified to E-Control.

In the interests of consumer protection, natural gas traders and suppliers selling natural gas to consumers must provide for an option to enter into non-interruptible natural gas supply contracts.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Consumer suppliers are subject to the Consumer Protection Act (*Konsumentenschutzgesetz*) and must publish their rates for universal service. They must deliver natural gas to consumers who claim their right to be supplied (ie, universal service obligation).

Smart metering

Under section 128 of the GWG, system operators must install smart meters at customer facilities without load profile meters. Operators must also, without delay, inform these consumers on the smart meter installation at their facility and the overall situation as regards meter installation.

B.7 Cross-border interconnectors

The Austria cross-border interconnectors are:

- Trans-Austria-Gas-Pipeline, ("TAG");
- March-Baumgarten Pipeline, ("MAB");
- South-East-Gas-Pipeline ("SOL");
- West-Austria-Gas-Pipeline ("WAG");
- Hungarian-Austria-Gas-Pipeline ("HAG");
- Penta-West-Pipeline ("PW"); and
- Kittsee-Petrzalka Pipeline ("KIP").

C. Energy trading

C.1 Electricity trading

Since the liberalisation of the electricity market, electricity trading has become an increasingly important factor for all market players. In Austria, electricity trading is both physical and financial.

Since March 2002, the Energy Exchange Austria AG ("EXAA") has been operating in the Austrian electricity market. EXAA is an energy exchange mainly for the Austrian energy market where power is traded physically. Generally, all companies wishing to participate at the European electricity market may trade on the exchange where EXAA takes over the central counterpart risk for the execution of financial transactions. EXAA is a neutral market organiser and a risk manager for all EXAA trading participants.

EXAA uses a completely internet-based trading system in which exchange members can enter orders in the trading system from 8am until 10:12am on exchange days (the minimum trading quantity is 0.1MWh). Under the double auction bidding system, demand and supply orders are settled anonymously at a specific moment after the market is closed.

The auction is organised every day at 10:15am. The physical completion of deals takes place the next day.

Contractual volumes are notified to the clearing and settlement centre one day in advance (before 2pm) if power is delivered within the market area. If power is delivered outside the market area (ie, outside Austria), the market area manager must be notified. However, electricity is largely traded on the basis of bilateral contracts (eg over-the-counter ("OTC")) where the trading terms of the European Federation of Energy Traders (EFET) can be used between parties.

In Austria, electricity can also be traded on the balancing market. The task of determination, price information and settlement of balance energy is observed in each market area by the balance group coordinators (eg, in the APG market area this is done by APCS Power Clearing and Settlement AG). The balance group coordinators, together with the market participants, network operators and market area manager, are responsible for the proper, neutral, and confidential handling of the market for balance energy.

Power suppliers who are also registered in a balance group for balance energy can offer balance energy to the balance group coordinator daily until 4pm. Balance energy is traded on the basis of a merit order list created by the balance group coordinator and the physical fulfilment takes place the next day.

Traders must either establish a balance group or join an existing one. Balance groups are established by balance responsible parties ("BRPs") within market areas. The activity performed by a BRP is subject to a notice issued by E-Control. The notice conditions are set out in the ElWOG 2010. Additionally, the Electricity Act of the provincial state of the BRP's company seat applies (eg the Viennese Electricity Act stipulates that electricity traders delivering electricity to end consumers must notify the commencement of their trading activities to the provincial government and must also inform the provincial government about their business locations); if a BRP does not have a company seat in Austria, the legislation of that province with which the strongest relation exists applies. To obtain a BRP notice, the requirements specified for this role in the GTCs of the clearing and settlement agent must be fulfilled. Foreign electricity traders do not have to establish a company or branch in Austria to be able to commence electricity trading. However, if no branch or company is established, a national process agent (*Zustellbevollmächtigter*) must be notified to E-Control. Typically, non-domestic electricity traders choose to establish their own balancing group.

C.2 Gas trading

Natural gas traders buying or selling natural gas for customers in Austria must obtain a trading licence and notify their activities to E-Control prior to their commencement. The GWG does not impose any obligation to obtain a licence on wholesale natural gas traders, which means no trading licence is required under Austrian natural gas law for wholesale traders. However, due to the introduction of the new market model introducing the entry/exit system, all gas traders trading on the VTP Baumgarten must notify their activities to E-Control.

Additionally, independent natural gas traders must register as balance group representatives who will be responsible for establishing a balance group in at least one of the three Austrian market areas (alternatively they can join an existing balance group). Therefore, natural gas traders have to conclude contracts with the clearing and settlement centre and the market area manager. The market area manager is responsible for network access and capacity management, scheduling, and balancing energy management and also long-term planning. On receipt of certain documents from the applicant, E-Control can grant the permission to participate in the Austrian natural gas market.

In Austria, natural gas trading mainly takes place at the CEGH. Trading can either take place OTC or on the gas exchange platform. In both cases, the gas trader must register with CEGH and conclude a CEGH Membership Agreement.

Access to the CEGH Gas Exchange is offered through the pan-European PEGAS platform and it is operated under the Powernext rulebook. The European Commodity and Clearing AG is the clearing agent and clearing house.

D. Nuclear energy

Under the Federal Act on the Prohibition of the Use of Nuclear Fission for the Energy Supply in Austria (*Bundesgesetz über das Verbot der Nutzung der Kernspaltung für die Energieversorgung in Österreich*), the construction of any facility that generates electricity for the supply of energy by nuclear fission is prohibited and existing facilities are not to be put in operation. This act is based on the Federal Constitutional Act for a Nuclear Free Austria (*Bundesverfassungsgesetz für ein atomfreies Österreich*).

E. Upstream

The exploration and production of oil and natural gas is regulated by the federal legislator in the MinroG, which contains provisions concerning the underground storage of natural gas without tanks and the purification of stored natural gas. An EIA must be conducted if the exploration of oil or natural gas exceeds 500,000 cubic metres per day ("m^3/d") (reduced thresholds of 250,000m^3/d applying to exploration fields located in a special protected area). The EIA approval, issued under the EIA Act, replaces the approval under the MinroG.

On an administrative level, the competent authorities are the Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation, and Technology and, where the EIA is required, the government of the state concerned (*Landesregierung*). Applicants can apply for remedies against decisions of the Federal Minister with the Constitutional and also the Administrative Court. The EIA decision, issued by the State Government, can be repealed to the Federal Administrative Court (*Bundesverwaltungsgericht*) and thereafter to the Constitutional and/or Administrative Court.

The search for, exploration of, and storage in non-hydrocarbon-bearing geological structures used to store oil or natural gas relies on the approval of the competent authority. To prevent malpractice, it is not possible to transfer the exercise of rights. However, the transfer of the approval is possible but must be notified to the relevant authority.

In Austria, OMV Exploration and Production GmbH, a partly federal state-owned company and the privately owned RAG carry out oil and natural gas development activities.

F. Renewable energy

F.1 Renewable energy

The Green Electricity Act ("ÖSG") was enacted in 2002 to implement the Directive on Electricity Production from Renewable Energy Sources (Directive 2001/77/EC), and it brought the previously fragmented support system for renewable energy under a single umbrella. The ÖSG provided two types of subsidies: guaranteed feed-in tariffs and investment grants. The EAG now provides the future regulatory framework for the promotion of the expansion of renewable energies, and the previous guaranteed feed-in tariff system is now being replaced by market premiums and self-marketing.

F.2 Renewable pre-qualifications

The general eligibility requirements regarding market premiums for renewables vary depending on the technology in question. There are no general eligibility requirements for wind power plantsunder the EAG-Market Premiums Ordinance 2022. New photovoltaic ("PV") systems, as well as extensions, with a bottleneck capacity of more than 10 kW peak are supported by market premiums.

F.3 Biofuel

The Renewable Energy Source ("RES") Directive sets a minimum share of renewable energy of 14% for the transport sector for 2030. Austria implemented the Biofuel Directive through the Ordinance on Fuels, under which biofuels are liquid or gaseous fuels produced from biomass and used in vehicle combustion engines. Biomass is the biodegradable part of the product. The main sources of biomass in Austria are wood products. Biodiesel is mainly produced from rape and oil-rich plants like sunflowers.

G. Climate change and sustainability

G.1 Climate change initiatives

Austria's '#mission2030' goals as well as the CEP were implemented in the EAG. Investment security for plants for the generation of electricity from renewable sources is to be ensured and citizens are enabled to jointly use the energy produced in renewable energy communities. The EAG provides in particular for:

- the establishment of renewable energy communities; and
- a fundamental change in the subsidy system to the market premium and investment subsidy model.

In accordance with these implementations, the Vienna Building Code (*Wiener Bauordnung*) imposes an obligation to install PV systems in almost all new buildings in Vienna. The Vienna Garages Act 2008 also imposes an obligation to install charging infrastructure for EVs in garages in certain cases.

G.2 Emission trading

In accordance with EU obligations, Austria has committed to reducing greenhouse gas emissions by 55% by 2030 compared to 1990 levels.

Under the Austrian federal system, European legislation concerning emission trading has been implemented by the federal legislator through the Austrian Emission Allowance Act (*Emissionszertifikategesetz* 2011) ("EZG"). This Act has been amended by National Emission Allowance Trading Act 2022 ("NEHG 2022"). The technical design and organizational procedures are governed by the Ordinance to the National Emissions Allowance Trading Act 2022 ("NEHG-DV 2022"). In addition, the ordinance also contains regulations on the information system (eg, registration of the trading participant). Once registered, trading participants are required to prepare an Annual Greenhouse Gas Emission Report and Quarterly Greenhouse Gas Emission Reports and submit them via the Emissions Data Submission Portal ("NEIS"). The reports are used to calculate the number of national emission allowances. In addition, the trading participant must submit a simplified greenhouse gas emission report via NEIS by June 30 of the following year. This is based on a self-calculation by the trading participant. The comprehensive exemptions are not yet enacted due to the lack of approval under state aid law by the European Commission.

Particularly due to the Covid-19 pandemic, low allocations of allowances are expected in the allocation period 2021 to 2030, as the significant changes in plant utilisation and the activity rate will lead to an adjustment of the number of allocated emission allowances.

Provided that the emission certificate is registered at the Emission Certificate Registry Austria GmbH ("ECRA"), the purchase and sale of certificates can be agreed directly between companies or can also take place via exchanges, including the EXAA.

G.3 Carbon pricing

In 2018, effective carbon rates in Austria consisted of fuel excise taxes and, to a smaller extent, of permit prices from the EU-ETS. Austria does not have an explicit carbon tax but has announced its intention to introduce some form of carbon pricing such as a tax on CO_2 emissions.

G.4 Capacity markets

An energy only market has been established in Austria (see section A.3). Therefore, there is no predominant regulatory regime relating to capacity markets.

H. Energy transition

H.1 Overview

Regarding the pathway toward transformation of the energy sector from fossil-based to zero-carbon, Austria will adopt a comprehensive new legislative package (EAG), which includes energy communities. Citizens will be able to operate their PV systems and share the energy generated with other members.

H.2 Renewable fuels

Hydrogen

Austria is increasing its share of renewable energy by developing a hydrogen strategy and putting conditions in place for feeding renewable hydrogen into existing natural gas infrastructure. Therefore, the state is envisaged to act on promoting investments, exempting taxation, and addressing the legal framework. To date, the relevant laws for the Austrian energy industry, the ElWOG 2010 and the GWG 2011, make hardly any reference to hydrogen-related technologies.

As of 2021, hydrogen and 'biogas' are no longer subject to the Mineral Oil Tax Act but are subject to the Natural Gas Tax Act. Austria is planning a tax exemption, whereby currently the amount of the levy for hydrogen is €0.021/m^3.

H.3 Carbon capture and storage

In Austria the nine provincial states have to transpose the carbon capture and storage directive, ie the CCS Directive, into national legislation (*Umwelthaftungsgesetze*).

In 2011, the Act Prohibiting the Geological Storage of Carbon Dioxide (*Gesetz über das Verbot der geologischen Speicherung von Kohlenstoffdioxid*) entered into force and bans CO_2 storage and the exploration of cavities.

H.4 Oil and gas platform electrification

Depending on the specific project, authorisations may be required under the MinroG, and the Nature Conservation Acts of the provincial states or the Water Rights Act. For projects covered by the EIA Act, the competent authority issues a single decision, covering all necessary licences (a 'one-stop-shop').

H.5 Industrial hubs

To the extent a project is covered by the EIA Act, the competent authority issues a single decision, covering all necessary licences.

H.6 Smart cities

Vienna was ranked, for the second year in a row, first in the Smart City Strategy Index 2019. The 'Smart City Wien' framework is a long-term umbrella strategy for 2050, which aims to significantly reduce the amount of resources, eg energy usage or waste used. Vienna is, among other things, focused on employing intelligent building technologies in new constructions as well as setting up smart grids.

I. Environmental, social and governance (ESG)

In Austria, federal as well as state laws deal with ESG, such as the EIA Act, the Water Rights Act, the Animal Protection Law, and the Waste Management Act. A significant ESG-related regulation can be found in the Austrian Commercial Code regarding the obligation for certain large companies to prepare a sustainability report.

Energy law in Belgium

Recent developments in the Belgian energy market

Lode Van Den Hende, partner, and Brecht Valcke, associate locum, both of Herbert Smith Freehills

Nationally

Belgium has increased competition in the electricity and natural gas markets and reduced its reliance on fossil fuels.[1] By 2025, Belgium wishes to phase out nuclear energy and has thus increased its generation of electricity from renewable sources such as wind (offshore and onshore), solar, and hydro power. By 2050, in line with the European Green Deal and the Paris Agreement, Belgium wishes to be 100% carbon neutral.[2]

Belgium is heavily focusing on renewable energy after phasing out coal-fired power plants in 2016. Belgium is also a global leader in energy production from offshore windfarms, having generated 2.23GW in 2020 and aiming to produce 4.5GW by 2030. In 2021, Elia, the transmission network operator in Belgium, reported that 43% (11,334MW of the 26,225MW) of the installed capacity was renewable energy with an aim to reach 100% by 2032.[3] This is an increase of 6% compared to 2020, when 37% (9,375MW of the 25,148MW) of the installed capacity came from renewable energy.[4] Although most Belgian energy production comes from nuclear plants, the Belgian Government ("Government") is committed to phasing out nuclear power by 2025. Out of fear of failing to meet the energy demand, partially caused by the uncertainty surrounding the supply of gas and oil due to the current conflict between Ukraine and Russia and the subsequent sanctions imposed on Russia, the Government recently decided to keep open Belgium's two most recently constructed nuclear power plants, Doel 4 and Tihange 3, for another 10 years. The Government also plans to build two new gas plants. In 2020, 46.1% of Belgium's final energy consumption came from oil products, with 29.9% of imported crude oil in 2020 coming from Russia and 26.8% of Belgium's final energy consumption in 2020 coming from gas - 2.1% of imported liquefied natural gas ("LNG") coming from Russia.[5]

The parliamentary opposition has heavily criticised the Government and proposes that the Government extend the running of the two nuclear power plants for 20 years instead of ten, claiming that it would be more cost-effective and more environmentally friendly. In particular, the building of the two, less environmentally friendly, gas plants was met with scepticism and criticism. The decision to postpone the closure of the two nuclear power plants is also contingent on the agreement with their owner, Engie. On 9 January 2023, the Belgian federal Government and Engie-Electrabel reached a non-binding *Heads of Terms and Commencement of LTO Studies Agreement* to potentially restart nuclear powerplants Doel 3 and Tihange 4 and run them for a further 10 years.[6] Difficult negotiations regarding the feasibility of this are expected. This, coupled with the uncertainty of gas and oil supplies from Russia, will likely increase the price of energy for the consumer in the near future.

To counterbalance these concerns, the Government plans to invest €1.16 billion to accelerate the reduction in Belgium's dependence on fossil fuels. Specifically, the Government plans to increase the energy generated through wind farms and the energy generated from hydrogen and solar panels, as well as investing €25 million per annum into researching small modular nuclear reactors ("SMRs"). The Government also intends to increase passenger and freight usage of the environmentally friendly railway transportation systems.[7]

Belgium's primary energy production in 2020 was 155.06TWh, of which 62.8% came from nuclear energy, 29.9% from renewables and biofuels (including natural hydro, wind, solar, geothermal, solid and liquid biomass, biogas, renewable waste, and heat pumps), 4.8% from non-renewable waste and 2.4% from other sources such as recovery of heat from chemical processes and colliery gas from coal mines.[8]

More than a quarter (26.2%) of the electricity production in 2020 came from renewable energy, an increase of 180.9% (15.1TWh) from 2011. There has also been a significant reduction in the use of oil products (-58.7%) and solid fossil fuels (-65.5%) since 2011. Belgium produced 23.4TWh of gross electricity production from renewable energy in 2020, of which 54.5% came from wind, 21.8% from solar, 14.2% from solid biofuels, 4.3% from biogas, 3.9% renewable municipal waste, 1.1% from natural hydro and 0.1% from liquid biofuels.[9] Compared to 2019, there has been an increase in wind production by 30.9%, solar by 20.1% and a decrease of nuclear energy production by -21.0% (the latter mainly because of outages of several nuclear plants due to planned maintenance and technical problems).[10] Belgium had a net export of 0.3TWh of electricity in 2020, with net imports of 4.0TWh from the Netherlands, 0.8TWh from France, 0.2TWh from Germany, and net exports of 5.0TWh to the United Kingdom ("UK") (due to higher UK prices at peak time), and 0.3TWh to Luxembourg.[11]

Wind

In 2020, wind production increased by 30.9% from 2019, with 7.0TWh of electricity coming from offshore wind farms, which covers the average consumption of around 1.99 million Belgian households totalling almost 40% of all households in Belgium.[12] At the end of 2020, a total installed capacity of 2,261MW produced by nine offshore windfarms comprising 399 turbines were operational in the Belgian part of the North Sea (C-Power, Northwind (previously Eldepasco), Belwind, Nobelwind, Rentel, Norther, Seastar and Mermaid (together Seamaid), and Northwester 2). The gross production estimate of these nine windfarms is an average of 8.2TWh per annum, which would cover 10% of the gross Belgian electricity consumption, with zero carbon dioxide ("CO_2") emissions.[13] An additional zone (the Princess Elisabeth zone) is intended to produce 3.15 - 3.5GW of additional wind power. The zone will also include an energy island to produce, store, and transmit renewable energy. This plan was adopted by the council of ministers on 15 October 2021 and a tender process will be organised by the Belgian Federal Government. It is expected that this additional zone will allow Belgium to realise its goal of producing 5.4 - 5.8GW through offshore wind power by 2030, as per the federal coalition agreement adopted on 30 September 2020.[14] Belgium expects an increase in electricity generation by 2025 from both Offshore (about 9TWh)[15] and Onshore (about 7TWh)[16] wind generation. Many activities such as green energy (eg, through offshore wind turbines), fishing, shipping (with more than 300,000 ships annually) and other commercial and industrial activities, sand extraction, military training exercises, the gathering of data through buoys, measuring points, radars and masts, and tourism (swimming, kite and windsurfing, sailing, water skiing, walking, fishing, and sunbathing), take place in the relatively small stretch of the Belgian part of the North Sea, which is approximately 3,454 km^2 or 0.5% of the entire North Sea. To ensure these activities can take place together safely, Belgium has developed the Marine Spatial Plan, which is reviewed every six years and currently runs from 2020 to 2026. The plan also addresses concerns around the preservation of marine life and sustainable aquaculture, costal defence experiments to prevent flooding or heritage protection (with over 300 shipwrecks in the North Sea, popular with wreck divers and anglers, nine of which have been recognised as underwater cultural heritage as of February 2020).[17]

Solar

The use of solar generated power in 2020 saw a rise of 20.1% compared to 2019, an increase for the third year in a row. This is due to high retail energy prices and the Flemish Government reintroducing the support for residential and commercial rooftop photovoltaic ("PV") in June 2020 and reinstating investment subsidies in Flanders. It is expected that 1.5GW of electricity will be generated by solar power by 2025[18] with electricity generation from solar PV expected to be over 7TWh.[19]

Hydro

Belgium expects an increase in hydro power generated electricity of over 0.3TWh by 2025, following a steep decline before 2020.[20] The Port of Antwerp, Europe's largest port in size, and the Port of Zeebrugge, Belgium's premium LNG hub and offshore wind power plant, are focusing on becoming leading renewable energy hubs, for example, through importing and deploying hydrogen.[21] In October 2021, the Belgian Federal Government approved plans to develop Belgium into a hub for renewable hydrogen that would be able to supply other European countries. By 2026, it is expected that 100-160km of pipelines to transport liquid hydrogen will have been constructed.[22]

Renewable and biofuels

The Fluxys group, the independent operator of the natural gas transmission grid and storage infrastructure in Belgium, seeks to develop, in collaboration with the gas industry, complementary systems for the transportation of methane (both carbon-neutral bio methane and systemic methane, which will replace quantities of natural gas), hydrogen, and carbon, from 2025.[23] Some upcoming projects include:

- the import of hydrogen in Belgium, partnering with Deme, Engie, Exmar, Fluxys, Port of Anwerp, Port of Zeebrugge and WaterstofNet;
- European Hydrogen Backbone, a collaboration between Fluxys and ten other gas infrastructure companies, to reuse natural gas and develop a hydrogen infrastructure throughout Europe;
- Hyoffwind, a project to build an industrial-scale power-to-hydrogen facility in the port of Zeebrugge;
- the sustainable production of methanol with projects both in the port of Antwerp (Power-to-methanol Antwerp (CCU)) and the North Sea Port between the port of Ghent in Belgium and ports of Terneuzen and Vlissingen in the Netherlands (North-C-Methanol (CCU)); and
- the creation of a Green Gas Register.[24]

Biofuels fall under the competency of the federal administration and represented 14.2% of the gross electricity production from renewable energy in 2020.[25] Biofuel production installations can seek recognition in accordance with the Federal Act of 10 June 2006 and the Royal Decree of 22 June 2006 (regulated biofuels).

In accordance with European legislation, motor fuels for consumption must contain a minimum percentage of biofuels in accordance with the Bureau for Standardisation ("NBN") standards (10% bioethanol for the thinning of petrol (or 5% for petrol intended for older vehicles), and up to 7% Fatty Acid Methyl Ester (FAME) for the thinning of diesel).

These measures contributed to Belgium meeting its renewable energy consumption target under the EU's Renewable Energy Directive by 2020. 88.3% of consumption in the transport industry in 2020 used petroleum products, the remaining 11.7% came from biofuels (bioethanol and biodiesel), electricity (railway transport), and a limited quantity of natural gas.[26]

The oil companies that are subject to the Act on Biofuel Blending Obligations (17 July 2013) have a quarterly reporting duty to the Belgium Federal Government (*Algemene Directie Energie*). Failure to report will result in administrative penalties.

Energy hubs

A few examples of energy hubs are: Biosteam, located in Beringen (Flanders) powered by a biosteam plant[27] and Tweewaters, in Leuven (Flanders) powered by a biomass fired cogeneration unit providing 80% of the heat and 100% of electricity for the district.[28]

The Belgian region of Flanders has founded an energy research, development, and innovation hub called EnergyVille, with some innovations already deployed in Belgium: eg, a geothermal energy installation at Janssen Pharmaceutica, part of the Johnson & Johnson group, or a 30km heat network for grid operator Fluvius contributing to the reduction of carbon emissions.[29]

Implementation of EU regulations and directives

2020 target

The EU's Renewable Energy Directive imposed a target on Belgium of 13% of renewable energy consumption by 2020. In 2020, Belgium reached 12.1% of this target, achieving the remaining 0.99% by purchasing quantities of energy from renewable sources in Finland, Denmark, and Lithuania.[30]

Belgium did meet its target of 10% (11.3% achieved) of renewable energy to be used in the transport sector under the EU's Renewable Energy Directive, which is mainly the result of the Belgian Royal Decree of 4 May 2018, which imposed an increase in the blending obligation for biofuels in 2020. Belgium was slightly above its indicative target of an 18% reduction in primary energy consumption in 2020 under EU Directive 2012/27/EU on energy efficiency. However, this significant reduction was predominantly caused by better energy efficiency in the energy sector, due to the outage of several nuclear power plants in 2018. A further cause was the steep decrease of non-energy consumption and less international aviation, as result of the COVID-19 measures, although these have now largely been lifted.[31]

2030 target[32]

Belgium signed the United Nations 2030 Sustainable Development Goals in 2015, with an objective of reaching the target of 18% of renewable energy consumption by 2030. The Federal Planning Bureau of Belgium considers that meeting this objective is feasible, although there are doubts due to a lack of internal coordination regarding energy policies.

Belgium's National Energy and Climate Plan has set the following targets for 2030:[33]

- reduce greenhouse gas ("GHG") emissions from the energy sector by 35% from 2005 levels;
- reach 17.5% renewables in gross final energy consumption; and
- significantly reduce Belgium's energy demand.

EU's electricity directives

The Third Electricity Directive has been fully implemented at federal level, as well as by the three regions (the Flemish Region, the Brussels-Capital Region, and the Walloon Region). On the federal level, the Third Electricity Directive was implemented by the Act of 8 January 2012, amending the federal Electricity Act of 29 April 1999 ("Electricity Law"). Regionally, Flanders enacted the Decree of 8 July 2011, amending the Energy Decree of 8 May 2009, the Brussels Capital Region enacted the Edict of 20 July 2011, amending the Electricity Edict of 19 July 2001, and Wallonia enacted a series of smaller amending decrees and governmental orders.

In June 2019, a Fourth Energy Package (Electricity Directive 2019/944/EU and the Electricity Regulation 2019/943/EU, the Risk Preparedness Regulation 2019/941/EU, and the EU Agency for the Cooperation of Energy Regulators (ACER) Regulation 2019/942/EU were enacted. Delivering the European Green Deal was released as the Fifth Energy Package on 14 July 2021 aligning EU's energy targets with the new European Climate ambitions for 2030 and 2050.[34] As an EU Member State, Belgium submitted its Final Implementation Plan[35] as wells as its Integrated National Energy and Climate Plan for 2021-2030.[36]

EU's gas directives

The Third Gas Directive (amended on 17 April 2019) has been fully implemented at a federal level as well as by the three regions. At the federal level, the Third Gas Directive was implemented by the Act of 8 January 2012, amending the federal Gas Act of 12 April 1965. Regionally, Flanders implemented the Third Gas Directive through the Decree of 8 July 2011, amending the Energy Decree of 8 May 2009. The Brussels Capital Region enacted the Edict of 20 July 2011, amending the Gas Edict of 1 April 2004. Wallonia enacted the Third Gas Directive and also a series of smaller amending decrees and governmental orders.

Capacity remuneration mechanism

In accordance with EU regulations, Belgium developed its Capacity Remuneration Mechanism in 2020 which includes a pre-qualification and auction process.[37] It is intended to be implemented in the near future to grapple adequacy issues from 2025 in accordance with Belgium's intent to halt energy production from fossil and nuclear sources.[38]

Emission trading

On 14 July 2021, the European Commission adopted a series of legislative proposals under the fourth phase of the EU Emissions Trading System ("EU-ETS") (2021-2030) with the goal to achieve climate neutrality in the EU by 2050, including a net reduction of at least 55% in GHG emissions by 2030. The sectors covered by the EU-ETS are to reduce their emission by 43% compared to the 2005 levels. To assist with the increase of these emissions cuts, the overall number of emission allowance will decline at an annual rate of 2.2% (from 1.74%) from 2021. Between 2019 and 2023, the number of allowances put in reserve will double to 24%, and revert to 12% in 2024, and will be limited to the auction volume of the previous year. Holdings above this amount will lose their validity.[39]

Carbon pricing

Belgium does not have an explicit carbon tax. In 2018, 75% of Belgium's carbon emissions were priced from energy use and 24% at an Effective Carbon Rate (ECR) above €60 per tonne of CO_2, predominately from the road transport sector. Unpriced emissions largely originate from the industry and electricity sectors. Most of Belgium's ECRs come from fuel excise taxes and some from permit prices from the EU-ETS. Following the Conference of the Parties 21 (COP21) in Paris in 2015, Belgium began a national debate on carbon pricing in 2017, in an attempt to tackle sectors that fall outside the EU-ETS. The report was published on 29 June 2018 and outlined that 63% of Belgium's emissions in 2016 were non-ETS, of which the major contributors were transport (35%), buildings (31%) and agriculture (16%). The National Energy-Climate Plan (NECP) seeks to investigate the possibilities of a further carbon tax as well as further reducing carbon emissions and developing renewable energy between 2021 and 2030, in accordance with EU Regulations and policy.

Carbon capture and storage

The fourth EU-ETS phase implemented better targeted carbon leakage rules as well as the implementation of an Innovation Fund and Modernisation Fund to support low-carbon innovation and energy sector modernisation.[40]

Fluxys is a major player to move captured carbon to be re-used (eg, in products such as polymers, steel, or in the production of synthetic methane) or to where it will be stored.[41] Some other projects include the accreditation of the LNG terminal in Zeebrugge for the liquefaction to BioLNG[42] and carbon capture projects in the Scheldt Delta region (CCUS) and port of Anwerp (CCS).[43]

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Overview of the legal and regulatory framework in Belgium

A. Electricity

A.1 Industry structure

Nature of the market

The Belgian electricity market has been fully liberalised since 1 July 2003 in Flanders, and since 1 January 2007 in the Brussels Capital Region and Wallonia. Since then, residential consumers have been free to choose their electricity supplier.

In 2020, 17.8% of the Belgian energy consumption came from electricity.[1] Electricity generation from January 2016 to December 2021 averaged 6,954GWh per month, with an all-time high of 8,978GWh reached in March 2021 and a record low of 4,536GWh in September 2018.[2] Of the 89.4TWh of electricity generated in 2020 (4.5% or -9.1TWh lower than 2019 due to lower generation from nuclear), 38.5% came from nuclear, 30% from natural gas, 26.2% from renewable energy, 2.1% from solid fossil fuels and manufactured gases, 0.1% from oil products, and 3.1% from other sources such as pumped hydro, heat recovery and non-renewable waste.[3] In 2022, electricity consumption in Belgium fell by 3.3% (81.7 TWh) compared to 2021. This was mainly because of a drop in consumption of 8% on average for the period between October and December 2022, with an outline of 11.1% lower consumption in November 2022. This drop in consumption was caused by Belgian consumers saving energy due to the higher prices and unusually high winter temperatures.[4]

More than a quarter of the electricity generation comes from renewable energy, which has increased by 180.9% (15.1TWh) since 2011, and a steep reduction in the use of oil products (-58.7%) and solid fossil fuels (-65.5%). This was mainly caused by the closure of the last remaining power plant using solid fuels in 2016. The remaining source of fossil fuel electricity generation comes from manufactured gases from the iron and steel industry and small multi-fired combined heat and power ("CHP") plants. Belgium generated 23.4TWh of gross electricity generation from renewable energy in 2020, of which 54.5% was from wind, 21.8% from solar, 14.2% from solid biofuels, 4.3% from biogas, 3.9% renewable municipal waste, 1.1% from natural hydro and 0.1% from liquid biofuels.[5]

Belgium had a net export of 0.3TWh of electricity in 2020, with net imports of 4.0TWh from the Netherlands, 0.8TWh from France, 0.2TWh from Germany, and net exports of 5.0TWh to the United Kingdom ("UK") (due to higher UK prices at peak time), and 0.3TWh to Luxembourg.[6]

Electricity prices in 2020 decreased by 3.6% from 2019 levels to €27.5/kWh, of which 28.6% is the energy cost, 38.2% network rates (which decreased slightly) and 33.2% the constitutes taxes. The impact on the supply chain caused by the current conflict between Russian and Ukraine and the sanctions against Russia, coupled with expected difficult negotiations with Engie to keep open the two nuclear plants, will likely cause a price increase in the near future.[7] In an attempt to counterbalance these likely price increase, on 9 January 2023, the Belgian federal government and Engie-Electrabel reached a non-binding *Heads of Terms and Commencement of LTO Studies Agreement* to potential restart nuclear powerplants Doel 3 and Tihange 4 and run them for a further 10 years.[8] (For more information, see Section D.) Belgium and Norway also sign an energy cooperation agreement. (For more information, see Section F.)

Key market players

The principal electricity generators in the Belgian electricity market are Engie Electrabel and EDF Luminus (who took over SPE in 2010), holding 73% and 11% respectively, of the Belgian market share in 2020. The third player in the market is the 422MW combined cycle gas turbine plant T-Power, which represents 4% of the Belgian electricity generation capacity. Other electricity generation capacity consists of cogeneration plants on the sites of large industrial consumers, and renewable energy sources ("RES") such as small-scale hydropower units, photovoltaic ("PV") electricity generation, onshore and offshore wind turbines, and biomass plants. The remaining 12% of the market comprises companies with less than 3% of the market share.

The transmission network is operated and owned by Elia through its two entities; Elia System Operator SA/NV and Elia Asset NL. On 13 September 2002, Elia was licensed as Belgium's sole transmission system operator ("TSO") for a renewable period of 20 years. On 6 December 2012, the Commission for Electricity and Gas Regulation ("CREG") certified Elia as a full ownership unbundled TSO. On 31 December 2019, Elia Transmission Belgium SA/NV (ETB) took over the Belgian regulated activities of Elia System Operator SA/NV. On 6 May 2019, Elia's TSO designation was renewed for a new 20-year period, with effect from 17 September 2022.[9]

Elia is the Belgian TSO for both the high voltage grids (above 70kV and up to 380kV) and the lower voltage grids (between 30kV and 70kV) in all three of the Belgian regions (the Flemish Region, the Brussels-Capital Region, and the Walloon Region).[10]

The distribution grids (medium and low voltage electricity networks, generally below 30kV) are operated by 26 distribution system operators ("DSOs"). The operation of a distribution grid is subject to a licence, which is granted for a period of 20 years to the Brussels Capital Region DSOs and the Walloon DSOs, and for a period of 12 years to the Flemish DSOs.

Most licensed DSOs in Belgium are inter-municipal companies, some of which are wholly owned by the municipalities (which make them pure inter-municipal companies). However, the majority are jointly owned by municipalities and provinces. Seven of the DSOs in Wallonia are jointly owned by municipalities, provinces, and Electrabel, a subsidiary of Engie (which are mixed inter-municipal companies). On 13 May 2016, the Flemish Government issued a decree to allow for mixed inter-municipal companies to the extent that the unbundling provisions remain intact (ie, the private partner must be from outside the energy generation and supply sector).

The Belgian DSOs are grouped into operating companies. In Wallonia, the DSOs are ORES, Tecteo (Resa) (NETHYS), Regie de Wavre, AIESH and AIEG. In the Brussels Capital Region, the operating company is Sibelga. In Flanders, the operating companies are Eandis and Infrax who merged into Fluvius on 1 July 2018. They aim to enhance the efficiency and reduce the costs of the DSOs.

Regulatory authorities

The regulatory structure in Belgium is complex. Due to Belgium's federal structure, there is no single national regulatory authority. Instead, responsibilities are divided between the federal regulator, CREG[11], and the three regional energy regulators, ie, the Flemish Regulator for Electricity and Gas ("VREG") for Flanders[12] , the Brussels Energy Regulatory ("BRUGEL") for the Brussels Capital Region[13], and the Walloon Commission for Energy ("CwaPE") for Wallonia[14].

CREG was established on 10 January 2000. It advises the federal government and has a general role in overseeing the supervision and control of the electricity and gas market. CREG's competence covers the high voltage transmission grids (above 70kV) and remains to date the competent authority for transmission grid tariffs. As part of the sixth state reform (implemented by the special Act of 6 January 2014), the regional regulators are competent to set the distribution grid tariffs.

The regional regulators have competence over all aspects of the regulation of electricity distribution. They also award green certificates and manage the respective online data banks. The VREG and the CwaPE produce the technical regulations on the access, management, and extension of electricity distribution grids. DSOs intending to operate in Flanders are appointed by the VREG.

Legal framework

The most important federal act is the Act of 29 April 1999 regarding the Organisation of the Electricity Market (Official Gazette 11 May 1999) ("Electricity Law").

The most important pieces of legislation are:

- for Flanders, the Energy Decree of 8 May 2009 (Official Gazette 7 July 2009) and the Energy Governmental Decree of 19 November 2010 (Official Gazette 8 December 2010);
- for the Brussels Capital Region, the Edict of 19 July 2001 regarding the Organisation of the Electricity Market in the Brussels Capital Region (Official Gazette 17 November 2001); and
- for Wallonia, the Decree of 12 April 2001 regarding the Organisation of the Regional Electricity Market (Official Gazette 1 May 2001).

These pieces of legislation have all been amended several times to, among other things, ensure conformity with the European Union ("EU") electricity directives.

Implementation of EU electricity directives

The Third Electricity Directive has been fully implemented at the federal level, as well as by the three regions. On the federal level, the Third Electricity Directive was implemented by the Act of 8 January 2012, amending the Electricity Law. Regionally, Flanders enacted the Decree of 8 July 2011, amending the Energy Decree of 8 May 2009, the Brussels Capital Region enacted the Edict of 20 July 2011, amending the Electricity Edict of 19 July 2001, and Wallonia enacted a series of smaller amending decrees and governmental orders.

In June 2019, a Fourth Energy Package (Electricity Directive 2019/944/EU and the Electricity Regulation 2019/943/EU, the Risk Preparedness Regulation 2019/941/EU, and the EU Agency for the Cooperation of Energy Regulators (ACER) Regulation 2019/942/EU were enacted. Delivering the European Green Deal was released as the Fifth Energy Package on 14 July 2021, aligning EU's energy targets with the new European Climate ambitions for 2030 and 2050.[15] As an EU Member State, Belgium submitted its Final implementation plan[16] as well as its integrated national energy and climate plan for 2021-2030[17].

A.2 Third party access regime

Electricity suppliers, intermediaries, and large electricity generators are entitled to regulated access to the transmission grid. Customers (ie, grid users) wishing to inject electricity into, or take electricity from the Elia grid must first enter into an access contract and submit an access request to Elia. The grid user must also designate the Access Responsible Party ("ARP") and the supplier for the access points to which the contract applies.[18]

CREG has approved the form of the access contract, which is a standard contract that sets out the access-related rights and obligations of both Elia and the relevant customer, such as provisions concerning access tariffs and connection tariffs. The access contract applies to all access points for which the access holder has been granted access and which are recorded in the register of access points. The contract will only come into force once the customer has given a bank guarantee.

The transmission grid tariffs were approved by CREG on 7 November 2019 for the 1 January 2020 to 31 December 2023 period.[19] They include charges for connection to the transmission grid, for use of the transmission grid, for ancillary services, for balancing services, for external inconsistencies between the nominations of two ARPs, for public service obligations ("PSOs") imposed on Elia and for surcharges. At the end of the tariff period, CREG will compare the actual costs incurred with the estimated costs and will carry over any difference to the next tariff period.

Access to the distribution grids is regulated and DSOs must not discriminate between the different suppliers. The distribution grid tariffs are set by the regional regulators and calculated on a "cost plus" basis.

A.3 Market design

Contracts to be concluded[20]

In addition to signing an access contract with the TSO (see section A.2), a supplier must ensure that there is an ARP for each access point, which is ensured by entering into an ARP contract with Elia. The new supplier may either take on the role of the ARP itself or appoint a third party to do so. The ARP is responsible for maintaining a quarter-hourly balance between total injections and total withdrawals of the grid users in its portfolio. The ARP may be a generator, a major customer, an energy supplier, or a trader. If the balance perimeter of an ARP is off-balance, the ARP must pay imbalance tariffs to Elia.

In order to have access to the distribution grid, a supplier must enter into a regulated access agreement with the DSO.

A framework agreement exists for all of the supplier's customers that are domiciled within the territory of the DSO rather than an agreement for each separate connection.

Capacity trading[21]

The Belgian electricity grid has been interconnected with the electricity grids of the Netherlands and France and coupled to the Central West Europe region since May 2015, as well as with Germany since November 2020 through the ALEGrO interconnector[22]. Each ARP can exchange energy (ie, import or export) with a view to maintaining the balance between generation and consumption at the injection point for which it is responsible. Different allocation mechanisms are used to allocate annual, monthly, daily, and intraday capacities. The annual and monthly capacities are allocated using explicit auctions at which the ARP can acquire the right to import or export a certain volume (in MW) of power for each hour of the year, month, or day in question. TSOs in 17 EU countries have created shared rules governing these explicit auctions, which are organised through a joint company called Joint Allocation Office.

Daily capacity is allocated to market players through an implicit allocation mechanism, which is organised by the power exchanges via market coupling (see section C.1). Since October 2016, the intraday capacity is allocated through an implicit mechanism based on continuous trading on the intraday markets of the European Power Exchange ("EPEX") by means of the M7 trading platform.

When the ARP has acquired capacity through the explicit allocation mechanism, it must nominate or schedule the volumes it wishes to import and export. The ARP must therefore submit a nomination to the TSO of the exporting country and one to the TSO of the importing country. The system operators check to ensure that the details of the two nominations correspond. For implicit capacity allocation, the ARP does not have to nominate its import or export capacity as cross border capacity is assigned based on the bids and offers made in the markets on either side of the border. The clearing house of the power exchanges organises the cross-border shipping.

Capacity obtained by a participant can be resold or transferred via the secondary capacity market.

A.4 Tariff regulation

The supply prices of electricity are composed of: (a) the actual electricity price, (b) the transmission and distribution grid tariffs, and (c) surcharges and taxes.

Certain price-regulating measures apply to these supply prices. Firstly, electricity suppliers have a general obligation to ensure that their prices are objectively related to their costs. Secondly, a 'safety net regulation' (*vangnetregulering*) was introduced by the Federal Act of 8 January 2012, focusing on electricity supply contracts for residential consumers and small and medium-sized enterprises ("SMEs") with variable prices. The safety net regulation provides that the prices under the residential and SME contracts can only be indexed every three months, in accordance with an exhaustive list of market-linked parameters. Parameters that relate to staff expenses, and depreciation or exploitation costs are prohibited. Following every indexation, CREG tests whether the indexation formula used by a supplier was applied correctly, and whether the proposed formula conforms to the exhaustive list of parameters. Additionally, electricity suppliers must report to CREG any increases in the variable prices for residential consumers and SMEs that are not caused by indexation. CREG must then approve any increases.

The Belgian Government terminated the safety net regime on 31 December 2017.

A.5 Market entry

Building and operating new electricity generating facilities can be done by any entity, provided they obtain a federal generation permit. This permit is issued by the federal Minister for Energy (currently a Secretary of State) following advice from CREG. Plants with a capacity of less than 25MW are exempt from this permit requirement, however, a notice must be sent to CREG and the federal Minister for Energy. In addition to the generation permit, generation facilities must have environmental and building permits. Alterations to existing generation facilities require similar prior approval from the federal Minister for Energy, except when net generating capacity will not be increased by more than 10% or 25MW.

A supply licence is required to engage in retail supply. In Flanders, the VREG may only grant this supply licence to individuals or companies that operate independently from the TSO and the DSOs. Licensed suppliers must also comply with the criteria established by the Electricity Law, supplemented by regional decrees/edict (see section A.1), such as having sufficient technical and financial capacity. In the Brussels Capital Region and Wallonia, the supply licences are granted by the Brussels Government and the Walloon Minister for Energy, respectively.

A.6 Public service obligations and smart metering and electric vehicles

Public service obligations (PSOs)

The federal government established a system of social maximum prices, obliging electricity and gas suppliers to supply energy at a fixed price to certain customers. This price is usually set by CREG and adjusted every six months to the lowest commercial tariff on the market for electricity; however, since July 2020, it has been set every three months and tariff increases are capped from one quarter to the next. Only protected residential customers on low incomes or those in a vulnerable situation benefit from this tariff, which was about 34-36% lower than the average electricity retail price from 2017 to 2019. These protected customers are placed on the social tariff automatically, regardless of the supplier they choose. In 2021, 9.7% (or about 470,000) electricity consumers received the social tariff, which is up slightly from 9.1% (or around 438,000) in 2019. This can be explained by the expansion of the eligibility criteria in response to the COVID-19 pandemic. While the CREG approves the transmission tariffs and advises the Federal Government on electricity and gas markets and monitors wholesale market competition, it is the regional authorities (VREG, CWaPE and Brugel) that approve the distribution tariffs, monitor the retail market completion, advise the Regional Governments, and regulate the electricity distribution and compliance with regional PSOs. These PSOs vary between the regions, but overall, the PSOs prevent consumers who cannot pay their energy bill from being cut off from electricity and gas and allows them to receive electricity or gas from a last resort supplier, eg through the use of prepaid meters and federal regulated tariffs. The various DSOs fulfil this role of the last resort supplier.[23]

A DSO must always provide a minimal supply of electricity to its customers to ensure all persons can live in a dignified manner, even if the bills are not paid or the funds on the budget meter are exhausted. Customers must, however, still pay the cost for a minimal supply of electricity and DSOs can only terminate this minimal supply in very restricted circumstances, which are set out in more detail in the respective legislative decrees relating to the sector.

A budget meter is a device that can limit the supply of electricity, and which is paid for in advance. It may be installed in certain circumstances, such as at the request of suppliers for non-paying customers, or, for example, in the Namur region of Belgium as part of regional provisions in terms of PSOs.[24]

The different regions also provide incentives through loans or subsidies to improve the energy efficiency of a consumer's home or by offering an energy premium to low-income residents. The Federal Government is also discussing the introduction of a social tariff for heating and already operates a Social Heating Fund covering part of the bills on oil-based heating. Despite these measures, the number of electricity consumers cut off from electricity and gas increased slightly by 0.1% to 1.8% of electricity consumers (from 81,012 to 85,332) from 2017 to 2019. The increased protection in response to the COVID-19 pandemic will likely cause a further increase in 2020.[25]

Smart metering

On 29 June 2018, the Flemish Government passed legislation for a gradual roll-out of smart meters in Flanders anticipated to start in 2019. From 1 June 2019 onwards, only digital metering devices will be installed in Flanders. In Wallonia and the Brussels Capital Region, regional governmental decisions respectively of 19 and 20 July 2018 provide for smart meters to be installed for industrial consumers (over 6,000kWh per year), and newly built/renovated homes.

Electric vehicles

Within the national action plan for clean power for transport, policy measures were introduced to stimulate the use of alternative fuelled vehicles and related infrastructure. As of 2018, there were 9,244[26] electric vehicles ("EVs") in Belgium, and about 1,800 charging stations (as of 2017), most of which are located on privately owned or semi-public areas. Pedelecs, ie, electric bicycles, are very popular among the younger generation and this market is proving to be the fastest growing within electric mobility.

Various incentives are in place to encourage the use of EVs. Tax breaks are offered to companies that buy electric, hybrid, or fuel-cell vehicles, which applies a 120% deductibility rate and waives the tax worth up to €75 on office parking spaces if companies fit charging units. EVs also currently pay the lowest rate under the annual circulation tax in all three Belgian regions; the rate in Brussels is €82.10.[27] In January 2019, the Flemish Government began organising a group purchase scheme with extensive discounts to promote the use of EVs in Flanders. Belgian bus companies Van Hool, Green Propulsion, and VDL Bus Roeselare are very active in the EV area with the supply of electric buses.

A.7 Cross-border interconnectors

The Belgian control zone has several interconnectors with the Netherlands (northern border) and France (southern border). In 2016, a phase shift transformer was integrated and connected to an existing overhead line between Luxembourg and Belgium (Schifflange station between Aubange and Esch). In the context of the North Sea Countries Offshore Grid Initiative ("NSCOGI"), which aims to develop an integrated offshore energy network in the North Sea, a new interconnector has been constructed between the UK and Belgium, ie, the Nemo Link. A direct electricity interconnection between Belgium and Germany has been completed in 2020, ie, the ALEGrO project with a maximum commercial import capacity of 6,500MW for Belgium in 2020[28]. Belgium also connected with the United Kingdom and plans to connect with Denmark and Norway.[29]

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Belgium has only negligible economically recoverable resources of fossil energy and therefore relies heavily on imports of nearly 95% of its primary energy needs. Imports of crude oil were reported at 666.332 barrel/day in December 2018.[30]

46.1% of Belgium's energy consumption in 2020 came from oil products.[31] Of the net import of energy in 2020, 59.2% comprised oil products. 29.9% of imported crude oil was sourced from Russia, which is a concern considering the current conflict between Ukraine and Russia and trade sanctions imposed on Russia. On 3 December 2022, the European Union, of which Belgium is a Member State, imposed a price cap of US$ 60 per barrel of oil originating or exported from Russia, applicable from 5 December 2022.[32] 33.2% comes from OPEC (18.5% from Saudi Arabia and 8.5% from Nigeria), 8.8% from Norway, 8.2% from the UK, 7.8% from USA and 12.1% from other countries including Canada, Colombia, Cuba, France, Gabon, Kazakhstan, Trinidad and Tobago and unspecified

African countries.[33] Oil prices fell sharply in 2020 due to a fall in prices on the international market during the COVID-19 crisis. However, prices in 2021 have recovered to pre-corona levels. A change in fiscal policy has resulted in a higher diesel price than petrol price.[34]

Gas

26.8% of Belgium's energy consumption in 2020 came from natural gas.[35] Of Belgium's net import of energy in 2020, 33.3% was from natural gas.[36] Of this import, 48.5% of the gas consumed in Belgium entered via a gas pipeline coming from Norway, 41% from the Netherlands, 2.4% from the UK and 3.8% and 2.1% came by ship (liquified natural gas – "LNG") from Qatar and Russia, respectively. The remaining 2.2% came from other sources. However, only gas from Norway and imported LNG came entirely from that country of origin.[37] In 2020, the price of natural gas dropped by 13% compared to 2019 to an average of €5.0/kWh, of which 77.5% included energy, supply, and network costs, with VAT and other taxes representing 22.5%. This was mainly caused by the fall in wholesale prices during the COVID-19 crisis. However, the current conflict between Russia and Ukraine and sanctions imposed on Russia as well as the recovery of the market after COVID-19 are likely to cause an opposite effect on gas prices.[38] Similar as for the oil price, after Russia stopped gas supply to Europe, the European Union, of which Belgium is a Member State, agreed to a price cap on gas when prices exceed US$191.11 (or €180) per megawatt hour for three days.[39] Belgian Prime Minister, Alexander De Croo, wanted to go even further and cap the price on gas imported from any nation, not only from Russia.[40] The gap in the supply chain to Europe left by Russia will likely be filled by supply from Norway.[41]

The Belgian natural gas market has been fully liberalised since 1 July 2003 in Flanders and since 1 January 2007 in the Brussels Capital Region and Wallonia. Since then, residential consumers have been free to choose their gas supplier.

Belgium relies on imports for its gas consumption. The current import portfolio is diversified in both origin and type of supply. The Netherlands, Norway, the UK, and Germany are the principal pipeline suppliers. Part of the gas imported from the Netherlands and Germany comes from Russia. The LNG terminal in Zeebrugge allows for the import of LNG.

The Belgian natural gas high-pressure grid makes use of two different types of natural gas, ie, high-calorific natural gas and low-calorific natural gas. Low-calorific natural gas is imported from the Netherlands, the production of which in the Netherlands has declined faster than expected due to political decisions by the Dutch Government to limit the production due to safety concerns following seismic activity in the Groningen field. It is expected that the supplies of low-calorific natural gas may end in 2030 and these networks will then need to be transformed; such transformation will require large investment, among other things, from the DSOs.

On 1 October 2015, Creos Luxembourg (the operator of the Luxembourg national gas transmission grid) and Fluxys (the Belgium operator) merged the Luxembourg and Belgian gas market in one cross-border integrated gas market named the BeLux Area. With the creation of an integrated market, the entry/exit access fees between Belgium and Luxembourg fall away and the Zeebrugge Trading Point ("ZTP") has become the gas trading point for the integrated market. Grid users no longer have to reserve capacity at the Belgium and Luxembourg interconnection point to transmit gas between Belgium and Luxembourg. Amendments to the Law of 12 April 1965 ("Gas Law") were made to allow the natural gas TSO, Fluxys, to set up a cross-border joint venture, ie, Balansys, responsible for commercial balancing in a zone comprising of several national territories.

Key market players

The suppliers of natural gas to end consumers with a market share of over 5% in 2020 are: Engie (Electrabel) (36%), EDF Luminus (11%), Total Gas & Power (10%), Eni S.p.A. (9%), and Wingas (5%). The remaining 20 companies (together representing 29% of the Belgian market share) each hold a share of less than 5%; nine companies of which do not reach 1%.[42]

The number of system users with a federal gas supply permit has increased significantly from six suppliers in 2007 to 31 in 2017, which demonstrates the increasing competition in the Belgian gas market.

The transmission network is operated and owned by Fluxys. Fluxys was licensed as Belgium's sole TSO for a renewable period of 20 years by Royal Decree on 23 February 2010. CREG certified Fluxys as a full ownership unbundled TSO on 27 September 2012. Fluxys is also the operator of the Loenhout underground gas storage facility. Fluxys LNG, a wholly owned subsidiary of Fluxys, is the operator of the LNG terminal and the peak-shaving facility, both of which are in Zeebrugge. The Zeebrugge Seapipe Terminal and the Interconnector Zeebrugge Terminal ("IZT") are governed by international treaties.

The distribution grids are operated by 17 DSOs, which are in turn operated to a large extent by the same inter-municipal companies that operate the regional distribution grids for electricity. The operation of a distribution grid is subject to a licence, which is granted for a period of 20 years to the Brussels Capital Region DSOs and the Walloon DSOs, and for a period of 12 years to the Flemish DSOs.

Regulatory authorities

The regulatory structure is parallel to the one for the electricity market (see section A.1).

As the national regulator, CREG is responsible for the third-party access regime for the transmission network, the storage facility and the LNG terminal. CREG also remains the competent authority for the transmission grid tariffs.

The regional regulators are responsible for all aspects of the regulation of the distribution of natural gas and for setting the distribution grid tariffs. The VREG and the CWaPE produce the technical regulations relating to the access, management, and extension of natural gas distribution grids. BRUGEL has an advisory role with regard to these technical regulations. DSOs intending to operate in Flanders are appointed by the VREG.

Legal framework

The most important federal act is the Law of 12 April 1965 regarding the Transmission of Gaseous and Other Products by Pipeline (Official Gazette 7 May 1965).

The most important pieces of legislation are:

- for Flanders, the Energy Decree of 8 May 2009 (Official Gazette 7 July 2009) and the Energy Governmental Decree of 19 November 2010 (Official Gazette 8 December 2010);
- for the Brussels Capital Region, the Edict of 1 April 2004 regarding the Organisation of the Gas Market in the Brussels Capital Region (Official Gazette 26 April 2004, Title II); and
- for Wallonia, the Decree of 19 December 2002 regarding the Organisation of the Regional Gas Market (Official Gazette 11 February 2003).

These pieces of legislation have been amended several times to ensure, among other things, that they conform with the EU gas directives.

Implementation of EU gas directives

The Third Gas Directive (amended on 17 April 2019) has been fully implemented at federal level as well as by the three regions. At the federal level, the Third Gas Directive was implemented by the Act of 8 January 2012, amending the federal Gas Act of 12 April 1965. Regionally, Flanders implemented the Third Gas Directive through the Decree of 8 July 2011, amending the Energy Decree of 8 May 2009. The Brussels Capital Region enacted the Edict of 20 July 2011, amending the Gas Edict of 1 April 2004. Wallonia enacted the Third Gas Directive and also a series of smaller amending decrees and governmental orders.

Belgium has opted for the full ownership unbundling model at transmission level.

B.2 Third party access regime to gas transportation networks

The transmission grid is divided into two entry/exit zones,[43] ie, the H-zone and the L-zone. The H-zone corresponds to the physical high-calorific sub grid; the L-zone to the physical low-calorific sub grid.

Transmission services include entry/exit services, wheeling and operational capacity usage commitment services, capacity conversion services, cross border delivery services, the Zee Platform Service, capacity pooling, imbalance pooling, and gas quality conversion services (from high-calorific to low-calorific, and vice versa). The Zee Platform Service facilitates transfers of gas in the Zeebrugge area between the IZT, ZTP, LNG, and Zeebrugge Beach interconnection points. It enables grid users to transfer natural gas between two or more interconnection points without explicit capacity reservation and without any capacity limitation.

Entry and exit services at interconnection points can be subscribed in the form of bundled products with the relevant adjacent TSOs, as well as unbundled products at the TSO. The products are offered on the PRISMA European Capacity Platform. System users can trade natural gas using: (a) ZTP notional (virtual) trading services for the H-zone, (b) ZTP notional trading services for the L-zone, (c) Zeebrugge Beach physical trading services either over the counter ("OTC") through bilateral agreements with third parties or anonymously on the trade platform (physical trading services for the H-zone has been possible since 1 October 2017).

To ensure the reliable and efficient operation of the transmission grid for each zone, the total quantities of natural gas entering the transmission grid must, on a daily basis, be balanced with the total quantities of natural gas leaving the transmission grid or being consumed in Belgium. This balance between entry and exit is monitored on a cumulative basis for all hours of a given day. Grid users are responsible for the balance within their own portfolio. To this end, they have access to a virtual balancing position ZTP on which Fluxys itself is also active so that it can maintain the balance on the entire transmission grid.

Access to the distribution grids is also regulated and the DSOs must not discriminate between the different suppliers.

B.3 LNG terminals and storage facilities

LNG terminals

There is one LNG terminal facility in Belgium, which is at Zeebrugge. In 2004, Fluxys LNG concluded long-term contracts with three terminal users, ie, Qatar Petroleum/ExxonMobil (for 20 years), Distrigas (for 20 years) and Suez LNG Trading (for 15 years) for a total volume of 9 billion cubic metres ("bcm") of LNG. Short-term capacity is made available either on the primary market, if slot scheduling under the long-term contracts leaves sufficient space, or on the secondary market for those slots not used by a primary terminal user.

Gas storage[44]

Gas storage is possible in the underground storage facility in Loenhout, in which high-calorific gas is stored in buffer aquifers. The working storage volume is 0.7bcm. The Loenhout storage facility has a send-out capacity of 625,000 cubic metres per hour ("m^3/h") and an injection capacity of 325,000m^3/h.

B.4 Tariff regulation

Connection and access to the grid and balancing services are subject to regulated tariffs based on a proposal by the TSO. The tariffs are pre-approved by CREG for a regulatory period of four years.

The tariffs for transmission services were approved on 7 May 2019 for the period from 1 January 2020 until 31 December 2023. The tariffs for natural gas in Loenhout were approved on 20 December 2019, and the tariffs for balancing services for 2021 were approved on 29 September 2020. The distribution grid tariffs are set by the regional regulators. The tariffs for LNG terminal services at Zeebrugge for the period 2020 to 2044 was approved on 27 June 2019, with amendments approved on 9 July and 18 November 2020.[45]

B.5 Market entry

Licensing regime

End users and holders of a supply licence have access to the Belgian gas infrastructure at the tariffs approved by CREG. The subsoil storage of (natural) gas and the exploration activities for new subsoil storage are subject to a specific federal licence, in accordance with the federal Act of 18 July 1975. The construction and exploitation of a new transmission plant requires a transmission licence.

A supply licence is required to engage in retail supply. In the Flemish region, the VREG only grants such licences to individuals or companies that operate independently from the

TSO and the DSOs. Licensed suppliers must also comply with the criteria established by law, such as having sufficient technical and financial capacity. In the Brussels Capital Region and the Wallonia Region, the supply licences are granted by the Brussels Government and the Walloon Minister for Energy, respectively.

Contracts to be concluded

In order to subscribe for, and use, transmission services, a party must first register itself as a grid user. This registration entails entering into the Standard Transmission Agreement with Fluxys. This grid user must also adhere to the Access Code on Transmission and the Transmission Programme. The latest versions of these contracts were approved by CREG on 3 February 2022.[46]

Parallel contracts apply to the subscription for, and use of, LNG terminal services and storage services.

To have access to the distribution grid, a supplier must enter into a regulated access agreement with a DSO. This is a framework agreement for all of the supplier's customers that are domiciled within the territory of the DSO rather than a separate agreement for each connection.

Price control and safety net regulation

The safety net regulation requires that from 2015 onwards, the supply price of natural gas to residential consumers and SMEs with variable contracts can no longer be coupled to the oil index. For more on tariff regulation see section A.4.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The PSOs for natural gas suppliers are similar to those that exist for electricity suppliers (see section A.6). In 2021, 10% (or about 295,000) of gas consumers received the social tariff, which is slightly up from 9.9% in 2019. As for electricity consumers, the eligibility criteria for gas consumers to receive the social tariff was expanded in response to the COVID-19 pandemic in 2021, which explains the slight rise. The social tariff is about 34-38% lower than the average gas retail price between 2017-19. The number of consumers that were cut off from gas supplies decreased slightly to 2.3% of gas consumers (from 62,778 to 59,015) from 2017 to 2019. The increased protection in response to the COVID-19 pandemic will likely cause an increase in 2020.[47]

Smart metering

See section A.6.

B.7 Cross-border interconnectors

The Zeebrugge Hub is the main gas trading hub in Belgium. It is connected to the UK, the Norwegian offshore fields and the LNG producing countries.

With a total of 20 interconnection points,[48] the Belgian grid is a central crossroad for gas flows in North-western Europe. The grid is open for imports from Norway, the Netherlands, Russia, the UK, and LNG producing countries. It is open for export to the Netherlands, Germany, Luxembourg, France, the UK, and Southern Europe.

C. Energy trading

C.1 Electricity trading

Suppliers who do not generate their own electricity can purchase it from generators or on the electricity exchange.[49]

EPEX SPOT Belgium is the Belgian short-term, power exchange for electricity delivery to, and withdrawal from, the Belgian hub. The shareholders of EPEX SPOT are the EEX Group (51%) and HGRT (49%), a holding comprised of the TSOs Amprion, APG, Elia, RTE, Swissgrid, and Tennet.

EPEX SPOT Belgium facilitates anonymous, cleared trading in three different market segments, ie, a day-ahead market segment ("DAM"), a continuous intraday market segment ("CIM") and the reserve market segment. Prices for electricity on the Belgian DAM are determined via a double-sided blind auction. In all market segments, clearing and settlement facilities are provided by a central counterparty.

EPEX SPOT Belgium's DAM segment is coupled with the other spot power auction markets in the North-western European Region. The fixing process matches, according to the merit of the orders, not only the purchase and sales orders submitted on EPEX SPOT Belgium's DAM segment but, within the limits of the interconnection capacity made available by the system operators of the concerned markets, also the purchase and sales orders submitted on the coupled exchanges. The CIM is coupled with the Dutch intraday market operated by EPEX Netherlands.

To trade on EPEX SPOT Belgium, an applicant must (a) enter into a Participation Agreement Clearing Settlement Services ("CSS") with the central counterparty, ECC, (b) enter into an ARP contract with Elia or designate a third party as ARP, and (c) enter into an (indirect) Participation Agreement with EPEX SPOT Belgium (and a broker).

Belgian power futures are traded on the ICE Endex and the European Energy Exchange ("EEX"), which runs on an internet-linked trading system. The exchange is supported by liquidity providers who guarantee a constant supply of bid and ask prices within certain spread limits.

Since June 2018, intraday cross-border capacity at the Belgium-Netherlands and Belgium-France borders is allocated via an implicit mechanism based on continuous trading on the intraday markets of EPEX SPOT/EPEX SPOL Belgium and Nord Pool by means of their local trading platforms.

C.2 Gas trading

On the Belgian gas market, system users may trade title of natural gas using: (i) ZTP physical trading services (formerly Zeebrugge Beach services), (ii) ZTP notional trading services on the H zone and (iii) ZTP notional trading services on the L zone.

The trades can take place OTC through bilateral agreements with third parties or anonymously on the PEGAS-platform (the pan-European gas trading platform of EEX Group) or the web-ICE platform.

The PEGAS-platform was launched in April 2015 to accommodate intraday to next calendar year ZTP physical trading, including for spot and future instruments. From 1 October 2017, Fluxys Belgium harmonized the operational rules for ZTP physical trading with those for ZTP notional trading and the platforms now operates 24/7.[50]

D. Nuclear energy

The Belgian federal government has sole competence over nuclear activities In Belgium. The country has seven nuclear power plants, which are spread over two sites (Doel and Tihange). Together they have an installed capacity of 5,920.80MW. The power plants are owned (fully or largely) by Electrabel, with EDF-Luminus holding a minority stake in Doel 3, Doel 4, Tihange 2 and Tihange 3 (10%) and EDF Belgium holding a 50% stake In Tihange 1. In March 2017, 58% of the electricity generated in Belgium originated from nuclear energy.

In October 2018, six of the seven reactors were closed for repairs and maintenance; only the Doel 3 unit remained functional since returning online in July 2018. Two of these reactors have since been placed back online, ie, Thiange 1 and Doel 4, which joined the grid on 12 November and 15 December 2018, respectively. However, four of the seven nuclear reactors continue to be unavailable and are expected to be so for some time.

The Act of 31 January 2003, ie, Nuclear Phase-Out Act, arranges that all nuclear power plants would be decommissioned after 40 years of industrial operation and that no new nuclear power plants may be built. The timetable could however be overruled by Royal Decree if closure of the nuclear plants threatens Belgium's electricity supply. The Act was amended in 2013 and 2015 to allow for further exploitation of Tihange 1, Doel 1 and Doel 2 until 2025. The current agenda for decommissioning is between October 2022 and December 2025. To date, the country appears to be divided between nuclear energy advocates who stress the importance of nuclear energy in Belgium's energy mix and the possible effects on energy supply and price in the medium to long run, and those who are concerned about safety given the recent outages of some of the nuclear power plants.

Due to the current agenda for a nuclear exit and the current accelerated coal exit in Belgium's neighbouring countries, a replacement capacity of around 3.9GW is expected to be needed in Belgium as of 2025; an additional 1GW may also be needed for the years 2022 to 2025 due to the accelerated coal exit. In June 2019, Ella noted the need for replacement capacity[51] and in 2021, Belgium decided to investigate and adopt a Capacity Remuneration Mechanism (CRM) to prevent a lack of electricity following the planned phasing-out of all nuclear capacity by 2025 and the decommissioning of thermal generation capacities.[52] The federal government has recently (March 2022) decided to keep open these two reactors for another ten years, while also building two new gas plants, to meet the expected energy demand. The opposition fiercely criticises this decision, highlighting that keeping these reactors open for another 20 years would be more cost effective and environmentally friendly, especially when also planning to build to new and less environmentally friendly gas plants. The decision to keep these nuclear reactors open is also contingent on the approval from the owner, Engie. On 9 January 2023, the Belgian federal government and Engie-Electrabel ("Engie")reached a non-binding agreement, the "*Heads of Terms and Commencement of LTO Studies Agreement*" ("*Head of Terms*"), to potentially restart nuclear powerplants Doel 3 and Tihange 4 and run them for a further 10 years.[53] It is worth noting that, except for the start of the studies, this "agreement" is non-binding and the parties have set a *go/no go date* of 30 June 2023 to reach a final, binding agreement.

Under the current *Head of Terms* the parties agreed to "*make reasonable endeavours to restart the Doel 4 and Tihange 3 nuclear units*" by November 2026 at the earliest. Engie has previously indicated it will need about five years to prepare the extension of running a normal nuclear powerplant. It is, thus, likely the nuclear units will not be restarted until 1 November 2027, which is also the cut-off point agreed between the parties, although the government has no right of action against Engie would the plants not have been not restarted by then. Some key demands from Engie, with which the Belgian federal government was (forced) to agree are:[55]

- The date to restart the plants is non-binding and not enforceable. Unless the government can prove wilful misconduct from Engie, Engie has a best-efforts engagement only.
- A fixed maximum cost to store nuclear waste and for the dismantling of the power plants in the future, from 2036 at the earliest. While the exact numbers are yet to be agreed between the parties, it was agreed that Engie would pay the government the real price for the dismantling of the plants, and not less than the fixed maximum cost, while the government would not charge Engie more than the fixed maximum cost for the storage of nuclear waste in two parts.
- Engie and the Belgian federal government agreed to take 50-50 co-ownership of Doel 4 and Tihange 3. The costs to run and maintain the two powerplants for an additional ten years, as well as the costs to store the nuclear waste from running the plants an additional 10 years will be shared between the parties. This also means that the government will be liable for 50% of the losses or receive 50% of the gains. However, based on the losses sustained when the operation of older power plants Doel 1 and 2 and Tihange 1 were extended, it is likely that the running of Doel 4 and Tihange 3 will also be at a loss. It is also not clear whether Engie will charge the government a sale price to take 50% ownership, noting that Engie has already written-off the two plants in their books when they initially closed them.
- Because of the potential losses, Engie also demanded extra warranties from the government that Engie's losses in relation to the running of Doel 4 and Tihange 3 would be limited. Specific mechanisms have not yet been agreed between the parties, but possible scenarios could be: (1) the government "subsidising" Engie by guaranteeing a minimum sales price for the energy generated in the two plants. If the market price drops below this minimum price, the government (ie, the Belgian taxpayer) would pay the difference to Engie, however, when the market price rises above the minimum price, the difference would flow to the government. (2) Another method would be to agree a fix profit margin over the costs to operate the two plants, similar to CREG regulating the margin and costs of gas supplier Fluxys and electricity transmission grid operator Elia.

It is worth noting that if Engie and the Belgian federal government do reach a final agreement on 30 June 2023, this agreement is subject to further approval by the European Union, likely in April 2024.

Difficult negotiations about feasibility and likely price increases to the customer are expected. The federal government is further investing €25 million per annum into research into small modular nuclear reactors (SMRs).[56]

To prevent operators of nuclear power plants from making excessive profits, given that the nuclear power plants were amortised in the pre-liberalisation era, the federal legislature introduced a Nuclear Repartition Contribution (*nucleare repartitiebijdrage*). In 2016, the contribution was set at €130 million, which due to reduced nuclear power capacity, is a considerably lower amount than in previous years. From 2017, the repartition contribution is a variable amount calculated as the higher of a certain threshold amount (set every three years) and 38% of the profit margin of the respective nuclear power plant.

E. Upstream

There are no upstream activities in Belgium.

F. Renewable energy

F.1 Renewable energy

6% of Belgium's energy consumption in 2020 came from renewable energy and waste. 29.9% of the primary energy generation came from renewables and biofuels. 26.2% of electricity came from renewable energy.[57]

2020 target

The EU's Renewable Energy Directive imposes a target of 13% of renewable energy consumption by 2020 on Belgium. In 2020, Belgium reached 12.1% of this target, making up the remaining 0.99% by purchasing quantities of energy from renewable sources in Finland, Denmark, and Lithuania.[58] Belgium also signed the United Nations 2030 Sustainable Development Goals in 2015, with an objective of reaching a target of 18% of renewable energy consumption by 2030. The Federal Planning Bureau of Belgium considers that meeting this objective is feasible although there are doubts due to a lack of internal coordination regarding energy policies.

2030 target[59]

Belgium's National Energy and Climate Plan has set the following targets for 2030:[60]

- reduce greenhouse gas emissions ("GHG") from the energy sector by 35% from 2005 levels;
- reach 17.5% renewables in gross final energy consumption; and
- significantly reduce energy demand.

Belgian-Norwegian energy cooperation agreement[61]

On 23 February 2022, Belgium and Norway entered into an energy cooperation agreement focusing on the exchange of knowledge and technology in relation to renewable energy (wind and sun), hydrogen, and the capture and storage of CO_2, building on Belgium's leading role in offshore wind-energy and hydrogen technology. After having linked energy grids with the United Kingdom, Belgium is hoping to build a North Sea energy coalition by also linking with Norway and Denmark. It is hoped that this coalition will reduce the dependency (and vulnerability) of the supply from Russia.[62]

Green certificates

The principal legal instrument for the promotion of investment in RES is the green certificate, and each Belgian region has established its own green certificates regime. In Flanders, green certificates are called GSCs (*groenestroomcertificaten*) and CHPs (*warmtekrachtcertificaten*); in the Brussels Capital Region, GPCs (*groenestroomcertificaten/certificats verts*); and in Wallonia, also GPCs (*certificats verts*).

There are also federal GPCs that are awarded to offshore wind parks and offshore hydroplants (the Belgian territorial waters and the Belgian exclusive economic zone remained under federal competence).

While the Flemish GSCs and CHPs are awarded on the basis of the green electricity generated (corrected by a banding factor), the Brussels and the Walloon GPCs are awarded on the basis of carbon dioxide ("CO_2") savings. Each licensed supplier must submit a certain number of GPCs, depending on the amount of electricity supplied (ie, the quota obligation). Suppliers can meet their quota obligation either by generating renewable energy (for which they are granted GPCs) or by acquiring GPCs on the market. Generators of green electricity are granted GPCs that they can then sell on the market. However, green electricity generators in Flanders and Wallonia can also sell their green certificates to the DSOs (Flanders) or the TSO (Wallonia) at a fixed price. Therefore, in these two regions, a minimum price is guaranteed to generators.

Offshore wind energy

At the end of 2020, a total installed capacity of 2261MW was generated by nine offshore windfarms comprising 399 turbines that were operational in the Belgian part of the North Sea (C-Power, Northwind (previously Eldepasco), Belwind, Nobelwind, Rentel, Norther, Seastar and Mermaid (together Seamaid), and Northwester 2). The gross generation estimate of these nine windfarms is an average of 8.2TWh per annum, which would cover 10% of the gross Belgian electricity consumption without CO_2 emissions.[63] An additional zone (the Princess Elisabeth zone) is intending to generate between 3.15 and 3.5GW by wind power. It will also include an energy island to generate, store, and transmit renewable energy. This plan was adopted by the council of ministers on 15 October 2021 (ie, the Marine Spatial Plan – see also below for further details) and a tender process will be organised by the Belgian Federal Government. It is expected that this additional zone will allow Belgium to realise their goal of generating between 5.4 and 5.8GW through offshore wind power by 2030, as was adopted in the federal coalition agreement of 30 September 2020.[64] Belgium expects an increase in electricity generation between now and 2025 from both Offshore (about 9TWh)[65] and Onshore (about 7TWh)[66] wind generation.

The Belgian support regime for offshore wind farms is currently based on offshore GPCs that are awarded by CREG to electricity generating installations that are in waters over which Belgium has jurisdiction. For offshore concessions with a financial close on or before 1 May 2014, the offshore GPCs can be sold to the TSO at a fixed minimum price of €107/MWh for electricity generation from the first 216MW installed, and €90/MWh for any additional capacity installed. For offshore concessions with a financial close after 1 May 2014, the price of the offshore GPCs is determined on the basis of the Levelised Cost of Energy ("LCOE"). CREG adapts these reference values per domain concession before financial close and thereafter every three years. Pressured by decreasing prices abroad (Borssele I and II by DONG Energy), a new Belgian support regime has been approved by the European Commission (the "Commission") (from a state aid perspective) for offshore concessions whereby the price of the GPCs is also determined on the basis of LCOE.

On 27 October 2017, the Belgian federal government announced that it had reached a deal in relation to the planned Mermaid and Seastar (together now Seamade) and Northwester 2 concessions, under which the projects will receive €79/MWh over a period of 16 years with a possible one-year extension. In 2020, wind generation has increased by 30.9% from 2019, with 7.0TWh of electricity coming from offshore wind farms, which is the average consumption of around 1.99 million Belgian households, which is almost 40% of all households in Belgium.[67]

Marine spatial plan[68]

By Decree of 20 March 2014, the Belgian federal government has adopted a marine spatial plan to maintain a balance between the developments on the North Sea and the environment. The plan includes a number of zoning areas relevant for offshore energy, including: (a) an area for the construction and operation of installations for the generation of electricity from water, currents or winds, (b) an area for the construction and operation of installations for the transport of electricity, (c) two areas intended for installations for energy storage and (d) areas intended for the laying and operation of pipelines and cables.

Additionally, Elia intends to enhance the capacity of the onshore electricity transmission grid in the province of West Flanders, ie, the Stevin project. It also plans to develop a meshed offshore grid, ie, the Belgian Offshore Grid, to ensure that the wind farms in the North Sea are optimally integrated into its onshore grid.

New legal framework

On 12 May 2019, the Belgian Parliament adopted a new law, amending the Electricity Law (see section A.1) that introduced a competitive bidding procedure for awarding domain concessions for the construction and operation of offshore renewable electricity generation installations. This aims to reduce considerably the cost of supporting offshore wind farms. Under the law, competitive bidding procedures will be organised, larger plots will be made available on the market for offshore generation installations, and the results of preliminary studies, paid by the administration, will be made available to potential bidders. The new law also aims to further reduce subsidies granted to offshore wind electricity generation while continuing to recognise that new wind farms are essential to achieving Belgium's commitments at EU level and within the framework of the Paris Agreement.[69]

Solar energy

Another strong increase in Belgium is the generation of solar energy. 2020 saw a rise of 20.1% compared to 2019, an increase for the third year in a row.[70] A sharp rise in electricity generation from solar PV is expected before 2025 (over 7TWh). [71]

Hydro

Belgium expects an increase of Hydro power generated electricity before 2025 estimated at over 0.3TWh, after a steep decline before 2020.[72]

F.2 Renewable pre-qualifications

Wind

Unlike most North Sea countries that use a competitive support allocation via auctioning, Belgium uses a negotiated procedure granting support for 19 years through a tax financed feed-in tariff and a pay-as-bid pricing mechanism, but no pre-qualification. Belgium uses a centralised model where public authorities pre-investigate and select sites where the development is to take place.[73]

Solar

In June 2020, the Flemish government reintroduced the support for residential and commercial rooftop PV expecting to generate 1.5GW electricity by 2025, pushed along by high retail energy prices and reinstated investment subsidies in Flanders.[74] A sharp rise in electricity generation from solar PV is expected before 2025 (over 7TWh).[75]

Carbon pricing

See section G.3.

Capacity Remuneration Mechanism

In accordance with EU regulations, Belgium developed their Capacity Remuneration Mechanism in 2020, including a pre-qualification and auction process[76] which is intended to be implemented in the near future to grapple potential adequacy issues from 2025 as a result of Belgium's intention to cease energy generation from fossil and nuclear sources.[77]

F.3 Biofuel

Biofuels fall under the competency of the federal administration and represented 14.2% of the gross electricity generation from renewable energy in 2020.[78] Biofuel installations can seek recognition in accordance with the Federal Act of 10 June 2006 and the Royal Decree of 22 June 2006 (regulated biofuels).

In accordance with European legislation, motor fuels that are to be consumed must contain a minimum percentage of biofuels in accordance with the Bureau for Standardisation ("NBN") standards (10% bioethanol for the thinning of petrol (or 5% for petrol intended for older vehicles), and up to 7% Fatty Acid Methyl Ester (FAME) for the thinning of diesel).

These measures contributed to Belgium meeting their renewable energy consumption target under the EU's Renewable Energy Directive by 2020, and more specifically to the 10% renewable energy consumption target in the transport sector as set by the Belgian federal government, which Belgium met in 2020.[79] 88.3% of consumption in the transport industry in 2020 used petroleum products, the remaining 11.7% came from biofuels (bioethanol and biodiesel), electricity (railway transport) and a limited amount of natural gas.[80]

The oil companies that are subject to the Act on Biofuel Blending Obligations (Law of 17 July 2013) have a quarterly reporting duty to the Belgium federal government (*Algemene Directie Energie*). Failure to report will result in administrative penalties.

G. Climate change and sustainability

G.1 Climate change initiatives

As Belgian powers on climate change are divided between the regional and the federal governments, Belgian climate policy needs to be coordinated. To this end, several bodies have been set up, such as the National Climate Commission ("NCC"), which deals with domestic climate issues (and the responsible body for adoption and implementation of the National Adaption Plan (see below)), and the Coordination Committee for International Environmental Policy, which provides Belgium's concerted views on environmental matters within numerous international organisations and bodies.

On 19 April 2017, the NCC adopted a National Adaptation plan (2016 to 2020) that identifies specific adaptation measures that must be taken at national level in order to strengthen cooperation and synergies between the different entitles on adaptation.

Furthermore, each region has adopted its own climate plan within its own area of competence.[81] These climate plans contain measures to reduce GHG emissions and to adapt to the (expected) effects of climate change. The federal and regional governments also periodically evaluate the impact of their policies and measures.

G.2 Emission trading

On 14 July 2021, the Commission adopted a series of legislative proposals under the fourth phase of the EU ETS (2021-2030) with the goal to achieve climate neutrality in the EU by 2050. This includes a net reduction of at least 55% in GHG emissions by 2030, with the sectors covered by the EU ETS to reduce their emissions by 43% compared to 2005 levels. To assist with the increase of these emissions cuts, the overall number of emission allowances will decline at an annual rate of 2.2% (from 1.74%) from 2021. Between 2019 and 2023, the number of allowances put in reserve will double to 24%, revert to 12% in 2024, and will be limited to the auction volume of the previous year. Holdings above this amount will lose their validity.[82]

G.3 Carbon pricing

Belgium does not have an explicit carbon tax. In 2018, 75% of Belgium's carbon emissions were priced from energy use and 24% at an Effective Carbon Rate (ECR) above €60 per tonne of CO_2, predominately from the road transport sector. Unpriced emissions largely originate from the industry and electricity sectors. Most of Belgium's ECRs come from fuel excise taxes and some from permit prices from the EU-ETS.[83] Following the Conference of Parties 21 (COP21) in Paris in 2015, Belgium began a national debate on carbon pricing in 2017 in an attempt to tackle sectors that fall outside the EU-ETS. The report of this was published on 29 June 2018. The report outlined that 63% of Belgium's emissions in 2016 were non-ETS, of which the major contributors were transport (35%), buildings (31%) and agriculture (16%).[84] The National Energy-Climate Plan (NECP) seeks to investigate the possibilities of a further carbon tax as well as further reducing carbon emissions and developing renewable energy between 2021-2030, in accordance with EU Regulations and policy.[85]

G.4 Capacity markets

On 15 March 2021, the Belgian government amended the Electricity Law implementing a capacity remuneration mechanism ("CRM"), which is supplemented by working rules, such as the Royal Decrees of 30 May 2021 and 29 May 2022.[86] This CRM aims at guaranteeing the electricity supply in Belgium in light of the Belgian government's intention to close its nuclear power plants by 2025. The system will operate technology-neutrally, ie, all forms of electricity generation, storage or management can apply. The remuneration will apply to the total needed capacity on the Belgian market, not only to the shortage, in an attempt to attract new investment as well as incentivising existing actors to invest or remain in the Belgian electricity market.

From 2021, there will be yearly auctions in October of a pre-determined volume of capacity (with a maximum of three, eight or 15 years of supply), which will be organised by the Belgian TSO. Successful tenders must then supply the capacity four years later, for which they will receive a monthly subsidy under the CRM during the year(s) of supply. From 2024, an additional, second yearly auction will be held. Successful tenders at this second auction must supply that capacity one year later. These two auctions should allow investment in technologies concerning both long (eg, gas) and short (eg, TSO) preparation times to supply the capacity. It also allows for the total needed volume to be adjusted more accurately (taking into consideration the latest figures) and at the lowest cost.[87]

The EU Commission investigated Belgium's CRM proposal thoroughly, but in the end approved it in line with the EU State aid rules.[88]

H. Energy transition

H.1 Overview

Belgium has increased competition in the electricity and natural gas markets and reduced its reliance on fossil fuels.[89] By 2025, Belgium wishes to cease the use of nuclear energy and has increased its generation of electricity from RES such as wind (offshore and onshore), solar, and hydro power. By 2050, in accordance with the European Green Deal and the Paris Agreement, Belgium wishes to be 100% carbon neutral.[90]

H.2 Renewable fuels

The Fluxys group, the independent operator of the natural gas transmission grid and storage infrastructure in Belgium seeks to develop, in collaboration with the industries, complementary systems for the transportation of methane (both carbon-neutral bio methane and systemic methane, which will replace quantities of natural gas), hydrogen and carbon from 2025.[91] Some upcoming projects include the import of hydrogen in Belgium with such partners as Deme, Engie, Exmar, Fluxys, Port of Anwerp, Port of Zeebrugge and WaterstofNet; European Hydrogen Backbone is a collaboration between Fluxyis and ten other gas infrastructure companies to reuse natural gas and develop a hydrogen infrastructure throughout Europe; Hyoffwind a project to build an industrial-scale power-to-hydrogen facility in the port of Zeebrugge; the sustainable production of methanol with projects both in the port of Antwerp (Power-to-methanol Antwerp (CCU)) and the North Sea Port between the port of Ghent in Belgium and ports of Terneuzen and Vlissingen in the Netherlands (North-C-Methanol (CCU)); the creation of a Green Gas Register.[92]

H.3 Carbon capture and storage

On 23 April 2009, the CCS Directive was adopted. All three Belgian regions have transposed the CCS Directive into law. Flanders implemented the Directive by a Decree of 8 May 2009 on the deep subsoil matters and by a related Governmental Order of 15 July 2011. The Government of the Brussels Capital Region adopted an order on the capture and storage of CO_2 on 2 February 2012. In Wallonia, the CCS Directive was implemented by a Decree of 10 July 2013. According to a 2017 report from the Commission on the implementation of the CCS Directive, the Commission recommends that the legislation of Belgium fully conforms to the CCS directive.

Belgium has some capacity, although limited, for CCS demonstration projects. According to a report dated May 2015 from the Global CSS Institute, together with 30 other countries (out of a group of 61 countries), Belgium is 'making progress' in their storage readiness assessment. To date, no large-scale CCS demonstration projects exist in Belgium, however there are smaller CCS initiatives taking place such as the LEI LAC project (ie, low emissions intensity lime and cement), which is part of the EU Horizon 2020, and which is currently in its FEED phase (ie, front end engineering design). The pilot plant will be hosted at a cement factory at Lixhe in Belgium.

Belgium also participates in Action 9 of the Strategic Energy Technology Plan ("SET-Plan"); Action 9 of the SET-Plan is dedicated to renewing efforts to demonstrate CCS in the EU and developing sustainable solutions for carbon capture and use.

The fourth EU-ETS phase also implemented better targeted carbon leakage rules as well as the implementation of an Innovation Fund and Modernisation Fund to support low-carbon innovation and energy sector modernisation.[93]

Fluxys is a major player to move captured carbon to be re-used (eg, in products such as polymers, steel, or in the production of synthetic methane) or to where it will be stored.[94] Some other projects include the accreditation of the LNG terminal in Zeebrugge for the liquefaction to BioLNG[95] and carbon capture projects in the Scheldt Delta region (CCUS) and port of Anwerp (CCS).[96]

Under the Belgian-Norwegian energy cooperation agreement (see Section F.1), Norwegian and Belgian energy companies, Equinor and Fluxys, respectively, plan to build an offshore pipeline to transport 20-40 million of tonnes of CO_2 per year between Belgium and Norway, using the port of Zeebrugge.[97]

H.4 Oil and gas platform electrification

Belgium is focussing heavily in moving away from the use of fossil fuels to generate electricity and invest in RES such as wind, solar, hydro and biofuels.[98] Contradicting this focus, however, is the Belgian federal government's proposal, notably from the Greens, to build two new gas plants to address the fear of a short-term energy shortage when Belgium steps away from Nuclear power by 2025, or 2036/7 if Doel 4 and Tihange 3 are to be reopened and run another 10 years (see section D).[99]

H.5 Industrial hubs

The Port of Antwerp, Europe's largest port in size and the Port of Zeebrugge, Belgium's premium LNG hub and offshore wind power plant, are focussing on becoming leading renewable energy hubs, eg, through import and deploying hydrogen.[100] In October 2021, the Belgian Federal Government approved plans to develop Belgium into a hub for renewable hydrogen that would be able to supply other countries in Europe. By 2026, between 100 and 160km of pipelines to transport liquid hydrogen are expected to have been laid.[101]

As discussed in section D.6, the Marine Spatial Plan seeks to develop an energy island for the generation and storage of offshore wind energy.[102]

Other examples of energy hubs in Belgium are: Biosteam, located in Beringen (Flanders) powered by a biosteam plant,[103] and Tweewaters, in Leuven (Flanders) powered by a biomass fired cogeneration unit providing 80% of the heat and 100% of electricity for the district.[104]

The Belgian region of Flanders has established an energy research, development, and innovation hub called EnergyVille, with some innovations already deployed in Belgium: eg, a geothermal energy installation at Janssen Pharmaceutica, part of the Johnson & Johnson group and a 30km heat network for grid operator Fluvius contributing to the reduction of carbon emissions.[105]

H.6 Smart cities

In June 2018, 589 Belgian cities and municipalities were asked to score themselves as to the progress of Smart City strategies. The scores show Belgium has progress to make with the ratings of: 3.53/10 (Flanders), 4/10 (Brussels) and 3.72/10 (Wallonia).[106] 35% of municipalities have already formalised Smart City objectives in their strategy.[107]

While more research and investment is needed, the different regions in Belgium are increasingly looking into the topic of smart cities.

Some examples include: in Flanders, the cities of Ghent, Antwerp, Mechelen, Kortrijk, Leuven, Ostend, Hasselt and Genk are part of the Flemish Smart Energy Cities Network.[108] The Brussels Capital Territory has eg, the Brussels Smart City project.[109] Wallonia cities like Namur and Liege[110] or Charleroi[111] also have some form of Smart City project.

I. Environmental, social and governance (ESG)

As has become clear throughout this article as well as the related recent development article, Belgium (and the EU, of which Belgium is a Member State) has increasingly focused on climate friendly solutions in its energy policy, phasing out reliance on fossil (and nuclear) power sources and heavily focusing on attracting investment in RES. According to a 2021 study by PWC, while lagging behind globally, Belgian Private Equity firms are increasingly taking into consideration ESG issues, such as the UN's Principles for Responsible Investing and other climate and human rights, such as the carbon footprint.[112]

Overall, Belgium is a stable country, politically and legally, with good prospects for (foreign) investment: Belgium's credit rating received a stable AA rating by all major players such as Moody's, Standard & Poor (S&P), Fitch, and DBRS. Consequently, Belgium is generally considered a stable and credit worthy country for investment.[113] The World Bank rated Belgium's legal rights as 'strong' (8 out of 12), which puts Belgium in the upper half globally.[114] Belgium has also been rated the 37th 'freest economy' in the world in 2022, and 24th out of 45 in the Europe region, which is above the regional and world averages.[115] Belgium signed 2,873 BITs (2,231 in force) and 429 treaties have investment provisions (TIPs) (335 in force).[116] While Belgium's political and legal system may be complex with both Federal and regional governments and regulations to take into consideration, overall '*[t]he [Belgian] investment regime is largely open, and government policies do not interfere significantly with foreign investment*'.[117]

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114. See www.data.worldbank.org/indicator/IC.LGL.CRED.XQ?end=2019&locations=BE&start=2019&view=map.

115. See www.heritage.org/index/country/belgium.

116. See www.investmentpolicy.unctad.org/international-investment-agreements/countries/19/belgium and www.investmentpolicy.unctad.org/country-navigator/21/belgium.

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Energy law in Bulgaria

Recent developments in the Bulgarian energy market

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Electricity markets

The most recent amendments in the Bulgarian energy legislation were driven by Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices. In accordance with the EU Regulation, Bulgaria introduced a revenue cap for inframarginal generators with installed capacity over 1 MW for the period from 1 December 2022 until 30 June 2023. Different caps were adopted for the respective producers, as follows:

- Nuclear – BGN180 (about €92) per MWh;
- Coal-fired condensing power plant – BGN350 (about €179), increased with the average monthly price per ton CO_2 emission allowance multiplied by 1.32, per MWh;
- Coal-fired power plant with added fuel from biomass and/or waste and/or petroleum products – BGN350 (about €179), increased with the average monthly price per ton CO_2 emission allowance multiplied by 0.9, per MWh;
- Renewable energy producers without a contract for compensation with premiums - BGN350 (about €179).

For renewable energy producers who are already receiving support from the state through a contract for premium the revenue cap is calculated in accordance with the specifics of the support scheme. Originally, renewable energy was promoted in Bulgaria through preferential feed-in tariffs under long-term power purchase agreements ("PPAs"). The PPAs were later replaced by feed-in premium agreements concluded with the Energy System Security Fund under which the producer must sell electricity at the free market in order to receive a premium payment. The premium compensates the producer for the difference between the market price and the repealed feed-in tariff.

On 1 January 2022, the Bulgarian Regulatory Commission adopted a decision which disrupted the feed-in premium incentive model; the amounts of the premium payments were updated to zero for most of the renewable energy producers. The decision was based on an analysis of the market which showed that the producers have higher revenues on the free market compared to their repealed preferential feed-in tariffs. The Regulatory Commission stated that in such cases, the producers should not receive premium payments on top of the market prices because such state aid, ie the premium payments, may be considered as unlawful.

The measures against high energy prices in Bulgaria affect not only the producers but also the electricity traders. The licensed traders must pay a contribution to the Energy System Security Fund for the transactions concluded on the free market for the period from 1 December 2022 until 30 June 2023. The amount of the contribution is calculated as the positive difference between the revenue without VAT and all expenses related to the purchase and sale of the quantities of electricity increased with 10% for wholesale customers or with 15% for end customers.

Price increases and government support for business consumers

As the electricity prices on the Bulgarian power exchange skyrocketed in H2 of 2021, eg the average price per MWh on the day-ahead market in December was BGN429.91 (about €219.15), the Bulgarian Government implemented a compensation mechanism for struggling business consumers. Such consumers benefit from a price reduction in accordance with the methodology applicable for the respective period. The compensations continue to apply in 2023.

Gas markets

Until the 2020 amendments in the Energy Act, the Bulgarian legislation did not require that natural gas traders must be licensed. However, as of 1 October 2021, natural gas trading may be performed only by traders licensed by the Regulatory Commission. The traders must prove that they meet certain technical, management, and financial requirements in order to obtain a licence and carry out commercial activities.

The Bulgarian public supplier of natural gas (Bulgargas EAD) is no longer obliged to sell gas at the organized exchange under a gas release program. The repealed provisions of the Energy Act envisaged that the public supplier must auction 8 720GWh in 2023 and 11 099GWh in 2024. The gas release program was initiated in 2020 with the purpose to facilitate competition on the wholesale market where Bulgargas EAD had a monopoly position. However, the Bulgarian Parliament decided that the termination of the program will be better for consumers in the current economic situation and will ultimately lead to reduced gas prices.

Significant projects and transactions

The Bulgarian Government continues to give high priority of gas infrastructure projects taking into account that natural gas may play an important role in the energy transition to net zero. The key gas projects include:

- Interconnection between Greece and Bulgaria ("ICGB").

The expected capacity for transportation of natural gas is from 3 to 5 billion cubic metres ("bcm") per year. The interconnection is vital for the diversification of the local gas supplies. Bulgaria will be able to import the negotiated quantities of 1bcm per year from the Shah Deniz gas field in Azerbaijan. Further, the interconnection will facilitate supplies from the LNG terminal in

Alexandroupolis, Greece.

- Interconnection between Serbia and Bulgaria ("IBS").

The interconnection will ensure the transportation of natural gas in both directions: from 1 to 1.8bcm per year towards Serbia and 0.15bcm per year towards Bulgaria. It is expected that the project will be completed by Q4 of 2023.

- LNG terminal in Alexandroupolis, Greece.

The Bulgarian state participates as a shareholder in the project – Bulgartransgaz EAD owns 20% of the shares in the project company. The LNG terminal is strategically positioned close to the transmission network of the Greek operator DESFA SA, so it will provide an excellent opportunity for diversification of the gas supplies in combination with ICGB.

In the private sector, the Bulgarian insurance and financial services company Eurohold acquired the assets of CEZ. CEZ Group is one of the largest market players in Bulgaria holding licences for energy distribution, end supply (over two million end consumers), and electricity trading. The mergers and acquisition market in the renewables sector is also on the rise. Some of the most notable transactions are the acquisition of the 42MW wind park near Kavarna by the Swiss based MET Group as well as the acquisition of the largest photovoltaic plant Karadzhalovo with installed capacity of 60MW by the Austrian based Energy.

Energy efficiency

With amendments in the Energy Efficiency Act from 2021, the Bulgarian government decided to pursue its energy savings targets by implementing alternative policy measures (fulfilled by the state) and energy efficiency obligation schemes ("EEOS") applicable to the energy suppliers for the period 2021 to 2030. The EEOS provides for annual individual targets of energy savings that must be achieved in the end consumption by certain energy companies. Under the EEOS, the energy suppliers that exceed certain sales thresholds must (see Overview of the legal and regulatory framework in Bulgaria, section G.1 for details) achieve the targets by offering energy efficient services, making payments to a special fund designated to make investments in energy efficiency projects, or purchasing energy savings certificates from other companies.

Energy outlook and challenges

Bulgaria has experienced political turmoil in recent years, with multiple unsuccessful elections until December 2021 when a Government was constituted. The newly elected Government did not last long and was dismissed after a successful no-confidence vote in the Bulgarian Parliament in June 2022. During such political instability, the main challenge is the adoption of all required amendments to the Bulgarian legislation so that the renewable energy projects under the National Recovery and Resilience Plan are realised in due time.

Despite the dynamic political situation, the Ministry of Energy and the Ministry of Environment and Water managed to prepare a key document for the energy sector in Bulgaria, ie the Integrated Plan in the Energy and Climate Sector of the Republic of Bulgaria for the period 2021 to 2030 ("Integrated Plan"). The Integrated Plan outlines the main priorities of the energy policies which are aimed at shaping the future of the local energy markets. Generally, the main goals under the Integrated Plan are to increase the share of renewables in final energy consumption to 27%, improve the energy efficiency of buildings and industrial processes, and introduce more electric and hybrid vehicles into public and private transport.

The Integrated Plan has received a certain amount of criticism citing that it does not provide for any concrete steps that will lead to fulfilment of the EU's decarbonisation goals, in particular, that Bulgaria still relies on the coal industry and the coal powered thermal plants to meet a significant part of its energy demand. All stakeholders must therefore look for solutions that follow a balanced approach between promoting energy from RES and sustaining local economies.

Overview of the legal and regulatory framework in Bulgaria

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Bulgaria has been legally liberalised and all consumers may choose a supplier on the free market. However, there is still a regulated segment. Most household consumers purchase electricity by the end suppliers for the respective region at regulated prices set by the Energy and Water Regulatory Commission ("Regulatory Commission"). On the other hand, the actual liberalisation for all business consumers was already completed. As of 1 October 2020, all business consumers connected at low voltage level had to switch to suppliers on the free market. Such consumers were granted a grace period until 30 June 2021 during which the consumers may continue to purchase electricity under a standardised contract approved by the Regulatory Commission.

Generally, the retail market is largely dominated by the group of companies of the three main end suppliers operating in Bulgaria. However, the options for consumers have significantly improved in the recent years, eg, there are 37 registered electricity traders on the platform operated by the Regulatory Commission where consumers can compare offers and prices. The online platform was launched in 2020 with the hope to facilitate the transition on the free market of all electricity consumers.

Key market players

The Bulgarian Energy Holding EAD ("BEH") owns several companies involved in the production and transmission of electricity. BEH is 100% owned by the Bulgarian state and is the largest state company based on assets. Under BEH's control are the nuclear power plant in Kozloduy, the TPP Maritza East II, the National Electric Company ("NEK"), and the Electricity System Operator ("ESO").

The total installed capacity of the Kozloduy NPP is 2,080MW. The Kozloduy NPP provides around one third of the annual electricity production in Bulgaria.

The total installed capacity of the thermal power plants (Maritza East II EAD, Contour Global Maritza East III AD, AES Maritza East I and Bobov Dol) using local coal stocks is 3,848MW. In 2019 these plants produced 39% of the gross electricity production in the country.

The main balancing installations in the energy system of Bulgaria are the hydro power plants owned by NEK. NEK is the largest renewable energy source ("RES") producer in Bulgaria and owns 31 hydro power plants with total installed capacity of 2,737MW in turbine mode and 931MW in pump mode. Until the full liberalisation of the Bulgarian market, NEK will provide services of public interest, ie in its capacity of public supplier NEK purchases the necessary quantities of electricity for the regulated market and then sells to the end suppliers which deliver to the household end consumers.

ESO is certified as the independent transmission operator in Bulgaria. ESO holds the nationwide licence for transmission and is responsible for the proper operation of the transmission network, as well as the cooperation with the transmission networks of neighboring countries.

The Bulgarian Independent Energy Exchange ("IBEX") was established in 2014 as a subsidiary of BEH. IBEX holds a ten-year licence for the operation of an organised exchange for electricity trading. IBEX is a member of the Multi-Regional Coupling as well as an associated member of the PCR (Price Coupling of Regions). As of 15 February 2018, the Bulgarian Stock Exchange AD is the sole owner of the shareholder's capital of IBEX.

The distribution and end supply of electricity is carried out by companies controlled by Eurohold, EVN, Energo-Pro, and ESP Golden Sands.

Regulatory authorities

The overall state policy in the Bulgarian energy sector is set out by the Bulgarian Parliament ("Parliament") and the Council of Ministers. The Parliament must adopt the Strategy for sustainable energy development of Bulgaria which sets out the main goals for development of the energy sector. The Minister of Energy is responsible for administering and carrying out the policy.

The Regulatory Commission is the independent national regulatory authority in charge of the energy sector regulation (both with respect to gas and electricity).

Legal framework

The main legal framework for energy activities is the Energy Act, which has been supplemented by secondary legislation such as ordinances, rules, decrees, decisions, and instructions. Renewable energy and biofuels are regulated in the Energy from Renewable Sources Act ("RES Act") and its secondary legislation. The key agreements in the energy sector are subject to general terms and conditions, which are approved by the Regulatory Commission. Others have statutory-mandated provisions.

Implementation of EU electricity directives

Both the Second and Third Electricity Directives have been widely implemented through the Energy Act. The provisions regarding market opening, third party access, generation, technical rules, and monitoring of security of supply have been fully transferred into national legislation.

A.2 Third party access regime

The transmission system operator ("TSO") and the distribution companies must provide access to the networks under non-discriminatory conditions. The TSO and the distribution companies may refuse access if such access is likely to cause technical issues, impact network security or result in a deterioration of supply for other consumers.

Under the Energy Act, transmission and distribution companies must connect producers or consumers to the network that:

- have entered into a written contract for connection with the transmission and/or distribution company (as applicable);
- meet the connection requirements;
- have constructed electrical installations in compliance with technical and safety requirements; and
- have entered into an access contract regulating the dispatching and the provision of ancillary services (applicable to producers).

The specific procedures are regulated in detail by the Rules for Granting Access to the Electricity Transmission and Distribution Networks issued by the Regulatory Commission and the Ordinance for Connecting the Producers and Consumers to the Electric Transmission and Electric Distribution Networks.

Regulated prices for connection and access to the transmission and/or distribution networks are set by the Regulatory Commission in accordance with the Ordinance for the Regulation of the Electricity Prices, under which a special methodology for each type of activity is applied.

Specific requirements for the connection and access to the transmission and distribution networks are provided within the agreements for connection and the agreements for access.

A.3 Market design

The electricity market includes bilateral agreements between market participants, an organised electricity exchange, a balancing electricity market, an energy reserves and ancillary services market and a capacity market, under the Electricity Trading Rules.

The licensing regime is applicable to most business activities related to electricity, and a new entrant must obtain the respective licence as a prerequisite for the start of its business activity (see section A.5). In particular, the licensing is mandatory for the following:

- generation of electricity, except for small-scale power plants with total installed capacity of up to 5MW;
- transmission of electricity (one licence for the territory of Bulgaria);
- distribution of electricity (one licence for the territory of a certain region with at least 150,000 consumers);
- trade of electricity;
- organisation of the electricity exchange (one licence for the territory of Bulgaria);
- public supply of electricity (one licence for the territory of Bulgaria);
- distribution of electricity in a closed distribution network;
- supply of electricity by end suppliers (one licence for a certain distribution region);
- distribution of electricity to the railway transport distribution networks (one licence for the territory of Bulgaria); and
- supplier of last resort. Only the holder of the licence for public supply and the end suppliers are eligible for this licence with regard to customers connected to the transmission network and to the distribution network.

Once the licence is obtained, the approval of the Regulatory Commission is required prior to any restructuring of the company holding the licence (including in case of a bankruptcy procedure) or in case of disposal of the title of ownership on the facility with which it performs the licensed activity (the same requirement also applies to mortgages or other encumbrances of property).

A legal entity applying for or holding one of the licences listed above can also be authorised to act as the coordinator of a balancing group, provided that it meets the requirements.

A.4 Tariff regulation

The Regulatory Commission establishes on an ex-ante basis the following:

- price for sale of electricity from producers to the public supplier within the availability determined by the Regulatory Commission (the Regulatory Commission makes a forecast of the monthly availability of the producers which sell to the public supplier and the respective quantities of electricity which the public supplier must sell to the end suppliers in order to meet the demand of the regulated market);
- price of the electricity sold by the public supplier to the end suppliers;
- prices for household customers connected to the distribution network at low voltage level;
- price for the transmission of electricity;
- price for connection to the transmission and/or distribution networks;
- price for the access to the transmission and distribution networks;
- the feed-in tariff and the premium for the sale of electricity generated from RES and combined production of electric and thermo power; and
- price or the element of the price through which all the end customers and the operators of the networks participate in the compensation of the non-refundable costs and the cost originating from the obligations to the society of the operators.

The regulated prices are set by the Regulatory Commission in accordance with the Ordinance for the Regulation of Electricity Prices, whereby a special methodology for each type of activity is applied. Under the Ordinance for the Regulation of Electricity

Prices, the regulatory period is the period between two regulatory reviews. It begins on 1 July of the respective year and lasts: (i) generally one year when the Regulatory Commission applies the method for the rate of return on capital; (ii) from two to five years when the Regulatory Commission applies the method for cap on prices and revenue; (iii) one year for the public supplier and the end suppliers. The regulatory review includes analysis and evaluation of the reported information for the base year provided by the energy companies and the forecast information for the next price/regulatory period. During the price period the prices do not change, generally for 12 months. However, the Regulatory Commission is entitled to adjust the prices during the price period if significant circumstances require such an adjustment.

A.5 Market entry

Authorisations

All electricity-related activities are subject to a licensing regime with some exceptions (see section A.3). The development, construction and commissioning of generation plants and transmission and distribution networks are regulated under the Spatial Development Act, with specific provisions under the Energy Act. The procedure for authorisation also involves approvals and coordination from environmental authorities. The specific requirements for the development of offshore energy infrastructure are set out in the law regulating the offshore territories of Bulgaria, ie the Maritime Space, Inland Waterways and Ports of the Republic of Bulgaria Act.

The licensing regime

The Regulatory Commission is responsible for issuing, amending, and withdrawing energy licences.

All electricity related activities are subject to a licensing regime with the exception of small plants generating electricity with a total installed capacity of up to 5MW. Local companies established under the Bulgarian Commerce Act and legal entities registered under the law of any EU Member State are eligible for a licence provided they meet certain technical, financial, material, and organisational requirements. Licences are issued for a term of up to 35 years and can be extended for a further similar term.

Under the licensing procedure the Regulatory Commission collects the following main fees:

- for review of the licence application: BGN1,000 (€511);
- initial licence fee: BGN15,000 (€7,670); and
- an annual fee for the licence: BGN2,000 (€1,022) plus 0.055% of the annual income from the licence activity.

A.6 Public service obligations, smart metering, and electric vehicles

Public service obligations (PSOs)

The Energy Act provides that energy companies must ensure the safety of the energy supply, without interruptions and with the required quality. Where such companies hold a monopoly, they have obligations under the Bulgarian Protection of Competition Act. The Minister of Energy can also impose additional public service obligations from time to time in order to ensure the continuity of the supplies, the protection of the environment, and the security of the critical energy infrastructure. Expenses incurred due to compliance with obligations with such orders of the Minister of Energy, are compensated on request to the Regulatory Commission.

Smart metering

The effective electricity metering regulations are set out in the Rules for Electricity Metering adopted by the Regulatory Commission in 2019. As of 2021, the operators of the electricity networks are not required to install smart meters. The Bulgarian Regulatory Commission may assess the economic feasibility of the smart metering implementation following a proposal of the network operators. However, for now smart metering is used only on a voluntary basis for some customers of the distribution companies.

Electric vehicles

The Bulgarian legislation has already made some minor steps to promote the use of electric vehicles ("EVs"). The Regulation for Planning and Designing the Communication and Transport Systems of Urbanised Areas sets out an obligation for a certain number of parking spaces for EVs at individual sites. Newly constructed public service buildings with more than ten parking spaces should have at least one in every ten parking spaces designated for EVs equipped with a high-power charging point, and the rest with normal power charging points.

Additionally, in some of the biggest municipalities in Bulgaria, including Sofia, EVs that are fully electric can park free of charge in the determined public zones for hourly paid parking. The owners of EVs do not owe local tax, as opposed to owners of conventional fuel vehicles.

A.7 Cross-border interconnectors

Interconnectors are considered part of the transmission network and are operated by the TSO. Bulgaria has nine active 400kV cross-border interconnectors, ie four with Romania, two with Turkey, one with North Macedonia, one with Serbia and one with Greece.

A new 400kV interconnector with Greece is under construction and has been announced as a Project of Common Interest under the TEN-E Regulation. It is expected that the interconnector will be commissioned in 2023.

B. Oil and gas

B.1 Industry structure

Nature of the market

Oil

Domestic oil resources are very limited, and production is marginal. Import, export, and trade in crude oil and refined products are completely liberalised.

Gas

The Bulgarian natural gas market includes a free market and a regulated segment. Regulated prices apply for: transactions between (i) the public supplier from one side and end suppliers and clients from the other; and (ii) the end suppliers and the consumers connected to the distribution networks. Consumers are legally allowed to switch to a supplier on the free market. However, most consumers still purchase natural gas at regulated prices.

The public supplier and the owner and operator of the gas transmission network are 100% state-owned. Generally, the natural gas market is fully open for competition; however, consumers do not obtain the full benefit of this liberalisation due to the monopoly position of Bulgargaz EAD, the insufficient domestic production of natural gas, and the lack of supply diversification.

Key market players

The Council of Ministers sets out the state policy for the gas sector. The Minister of Energy is responsible for administering and carrying out the policy.

The key market player is BEH through its wholly owned subsidiaries Bulgargaz EAD, the licensed public supplier of natural gas for Bulgaria and Bulgartransgaz EAD ("Bulgartransgaz"), which is the owner and operator of the gas transmission network licensed for transmission, transit, and storage of natural gas. Bulgartransgaz is also responsible for the maintenance, operation, management, and development of underground gas storage (the company owns the only underground gas storage facility in Bulgaria in Chiren).

Natural gas distribution in Bulgaria is provided by private local and regional companies. The key player with a market share of over 60% is Overgas AD followed by Aresgas EAD.

Gas Hub Balkan EAD ("BGH") operates the platform of the organised gas exchange in Bulgaria. It was established in 2019 by Bulgartransgaz. Currently, there are 48 registered traders and clients on the BGH.

Regulatory authorities

The Regulatory Commission is the regulatory authority in charge of licensing, overseeing, and coordination of the industry and its market.

Legal framework

The main legal framework of the natural gas sector, similar to the electricity sector, is set out in the Energy Act and the subordinated ordinances and regulations, as follows:

- Rules for trading with natural gas;
- Rules for balancing of the natural gas market;
- Rules for access to the gas transmission and distribution networks and for access to the storage facilities ("Access Rules").

Implementation of EU gas directives

The Third Gas Directive has been implemented in the Bulgarian legislation. Bulgaria has chosen the independent transmission operator ("ITO") model. The restructuring of Bulgartransgaz to separate the gas transmission system from the gas storage system has not been completed to date.

B.2 Third party access regime to gas transportation networks

Under the Energy Act, the transmission network operator and the distribution network operators must provide access on non-discriminatory terms to the transmission network and the distribution networks. Access may be denied if there is no capacity, or the access may lead to deterioration of the technical security of the network. It may also prevent the gas companies from performing the services of public interest or it may lead to serious financial difficulties due to contracts with 'take or pay' clause. The network operators that deny access due to no capacity or no connection point should make the necessary improvements if they are economically viable, or the client wishes to cover the expenses.

Access to the transmission network

An entity requesting access to the network must file a standard application form with Bulgartransgaz and provide a certificate of good standing, as well as sufficient evidence that the entity has not been declared bankrupt and it is not subject to liquidation or insolvency proceedings. Bulgartransgaz must review the application within three business days. If the applicant is approved, it can participate in the network capacity allocation procedure within six months of the date of the approval. The capacity allocation procedures are conducted via the Regional Booking Platform ("RBP").

Once the applicant is granted access to the transmission network, it may conclude an agreement for access and transportation, an agreement for sale and purchase of natural gas for balancing and an agreement for participation at the Virtual Trading Point ("VTP"). To secure the payments under the access and transportation agreement, the network user must provide a credit limit as a bank guarantee or a cash deposit with minimum amount of €2,500. The network user may book capacity products on the RBP up to the value guaranteed by the free credit limit at of the moment of the respective capacity allocation procedure. Under the agreement for sale and purchase of natural gas for balancing, the network user must provide an initial security in the amount of minimum 10% of the value of the monthly quantity as per the annual transportation schedule. Traders on the VTP must provide a security in accordance with the planned daily trading volumes at the VTP. For each day of trading activity, the security must cover the imbalances obligations, as well as the value of the traded daily volumes.

Access to the distribution networks

An entity requesting access to the distribution network files an application with the respective distribution operator indicating the information required under the procedure. If the distribution operator approves the access to the respective network, it will conclude an agreement with a requesting party. The draft template agreements and general terms and conditions for access to the distribution networks of each licensed distribution operator are approved by the Regulatory Commission.

B.3 LNG terminals and gas storage facilities

There are currently no liquefied natural gas ("LNG") terminals on Bulgarian territory. Bulgartransgaz owns 20% interest in the LNG terminal in Alexandroupolis, Greece which will play an important role in the diversification of the gas supplies.

Bulgaria has one underground gas storage facility in the village of Chiren, which holds the strategic national gas reserve. The current capacity of the underground storage is up to 550 million cubic metres.

Bulgartransgaz has issued Rules for Use of the Underground Storage Chiren, which provide obligations for the users of the storage facility in addition to the obligations stipulated in the Access Rules. No later than 30 calendar days before the beginning of the respective injection period, Bulgartransgaz must publish on its internet site the following information:

- available capacity for the gas months;
- number of units of integrated annual product; and
- the deadline for submitting applications for integrated annual capacity product for the subsequent gas year, which must be at least seven days after publication of the information.

B.4 Tariff regulation

Regulated prices for natural gas are established ex-ante by the Regulatory Commission for the following activities:

- sale of gas from the public supplier to the end suppliers and to entities licensed for the production and transmission of heat energy;
- sale of gas from the end suppliers to household customers and non-household customers for consumers connected to the gas distribution networks;
- connection to the networks;
- access and transportation of natural gas through the transmission and distribution networks except for where the Regulatory Commission approves a methodology for establishing such prices; and
- access and storage of natural gas in storage facilities.

The regulated prices are set by the Regulatory Commission in accordance with the Ordinance for the Regulation of Gas Prices; a special methodology is applied for each type of activity. Each month the Regulatory Commission approves the price at which the public supplier Bulgargaz sells to the end suppliers and to the entities licensed for the production and transmission of heat energy (the end suppliers sell to customers connected to the gas distribution networks).

B.5 Market entry

Licensing regime

Natural gas related activities are subject to a licensing procedure. Local companies established under the Bulgarian Commerce Act and legal entities registered under the law of any EU Member State are eligible for a licence, provided that they meet certain technical, financial, material, and organisational requirements. Licences are issued for a term of up to 35 years and can be extended for a further similar term.

The Regulatory Commission is responsible for licensing in the gas sector, and it authorises most of the activities related to natural gas, and in particular:

- transmission of natural gas;
- public supply (one licence for the territory of Bulgaria);
- distribution (one licence for the territory of a certain region, where at least 50,000 customers can be connected to the respective gas distribution networks);
- supply by end suppliers (one licence for the territory of a certain region);
- operation of the organised exchange for natural gas trading;
- trading (as of 1 October 2021); and
- storage of natural gas in a facility for storage and/or liquefying of natural gas or import, unloading and re-gasification of liquefied natural gas in a liquefied natural gas facility.

Once the licence is obtained, the approval of the Regulatory Commission is required prior to any restructuring of the company holding the licence (including in case of a bankruptcy procedure) or in the case of the disposal of the title of ownership of the facility with which it performs the licensed activity (the same requirement applies also to mortgages or other encumbrances of property).

The procedure and requirements related to licensing are regulated in detail in the Ordinance for Licensing of the Activities in the Energy Sector.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The Energy Act provides that the energy companies must ensure the safety of the energy (electricity, gas, heat) supply without interruptions and with the required quality (see section A.6).

Smart metering

Requirements for smart gas metering have not been introduced into the Bulgarian legislation.

B.7 Cross-border interconnectors

The following existing and operating cross-border interconnectors are part of the gas transmission network:

- Negru Voda 1(RO)/Kardam (BG): entry-exit point of the Bulgarian transmission network; interconnection point with STNG TRANSGAZ SA (Romania);
- Negru Voda 2.3 (RO)/Kardam (BG): entry point on the Bulgarian transmission network; interconnection point with STNG TRANSGAZ SA (Romania);
- Kulata (BG)/Sidirokastro (GR): entry-exit point of the Bulgarian transmission network; interconnection point with DESFA SA (Greece);
- Strandzha (BG)/Malkoclar (TR): exit point of the Bulgarian transmission network; interconnection point with BOTAS (Turkey);
- Strandzha 2 (BG)/Malkoclar (TR): entry point of the Bulgarian transmission network; interconnection point with BOTAS (Turkey);
- Kyustendil (BG)/Zidilovo (MK): exit point of the Bulgarian transmission network; interconnection point with GA-MA (North Macedonia);
- Ruse (BG)/Giurgiu (RO): entry-exit point of the Bulgarian transmission network; interconnection point with STNG TRANSGAZ SA (Romania); and
- Kireevo (BG)/Zaychar (RS): entry-exit point of the Bulgarian transmission network; interconnection point with GASTRANS (Serbia).

C. Energy trading

C.1 Electricity trading

Electricity is traded either at regulated prices (see section A.4), or at freely negotiated prices under bilateral agreements or at the IBEX, as well as at a balancing market under the Rules for Trading with Electricity ("ET Rules"). The following is subject to the ET Rules:

- electricity provided under bilateral agreements outside the power exchange;
- electricity provided on the power exchange;
- electricity provided on the balancing market;
- availability for participation in primary and secondary regulation;
- interconnection capacity;
- ancillary services;
- access to the network service, including system services;
- transmission of electricity and other network services; and
- balancing responsibility.

Market participants trade electricity under bilateral contracts at freely negotiated prices for each separate interval of delivery. The schedule of the deals is provided to the TSO on the day before the delivery or during the same day. The TSO and the operators of the distribution networks can purchase electricity only for their technical needs.

Market participants trade electricity on the power exchange, ie the IBEX, on a clearing price provided for each period by the operator of the exchange. Following recent amendments to the energy legislation, electricity producers with installed capacity of 500kW and above that sell electricity on freely negotiated prices must trade it on the IBEX. RES producers have the option to sell the generated electricity through the coordinator of their balancing group if they do not wish to participate directly at IBEX.

The balancing market for electricity is administered by the TSO. A deal is considered concluded on the balancing market once the supervisor from the TSO activates the proposal of the balancing energy suppliers.

C.2 Gas trading

Natural gas transactions are affected through written contracts, as set out under the Energy Act and the Rules for trading with natural gas.

Traders of natural gas may conclude contracts for:

- supply with the public supplier, end suppliers, consumers, other traders, as well as the TSO and distribution system operators ("DSOs") regarding their technical needs;
- transportation through the transmission/distribution networks;
- storage in a storage facility; and
- purchase and sale of natural gas for balancing.

The TSO administers the natural gas transactions, including the transactions at freely negotiated prices with points of delivery at the transmission network. Further, Bulgartransgaz operates a virtual trading point where buyers and sellers can purchase and sell natural gas without the need to book physical capacity.

Extraction companies, natural gas traders, end suppliers, TSOs, storage facility operators, liquefied natural gas facility operators, customers connected to the transmission network, market makers and liquidity suppliers conclude transactions with natural gas at freely negotiated prices. Such transactions with short-term standardised products and with products where the delivery period is less than or equal to one year must be concluded on an organised exchange, eg, on the BGH.

D. Nuclear energy

Activities in the nuclear energy sector are regulated under the Safe Use of Nuclear Energy Act. The Nuclear Regulatory Agency is the authority responsible for overseeing nuclear installations with regard to safety and radiation protection, as well as for the management of radioactive waste.

The 2,080MW NPP Kozloduy is the sole nuclear energy producer operating in Bulgaria. To comply with EU requirements, unit 3 and unit 4 of NPP Kozloduy were shut down by the Bulgarian Government ("Government") on 31 December 2006.

A project for the construction of a second nuclear power plant has been discussed by the Government since 1980. The actual steps for the realisation of this project were taken after 2002, and in 2005 it was decided that a 2,000MW Nuclear Power Plant ("NPP") would be built near the town of Belene. The Russian company Atomeksportstroi was selected as the constructor and the contract was signed on 18 January 2008. However, in 2012, the Government decided to terminate the development of the NPP project in Belene due to the lack of financial feasibility of the project. In January 2013, the decision whether to complete the NPP Belene was put to a national referendum. The public participation in the referendum was insufficient for a decisive result and the matter was brought back to the Parliament. In February 2013, the Parliament confirmed the termination of the NPP Belene project in favour of extended exploitation of the existing NPP Kozloduy. Following the cancellation of the NPP Belene project, Atomeksportstroi filed a lawsuit against NEK EAD in the court of arbitration in Paris, demanding compensation for the already manufactured equipment. In 2016, the court awarded Atomeksportstroi about €600 million. The resuming of the project has been discussed by the Government on numerous occasions but as of January 2023 the status remains unclear.

E. Upstream

Bulgaria has limited oil and natural gas resources located in the North-East part of the country and in the Black Sea. As of 20 January 2023, the number of granted concessions for extraction of oil and natural gas is 18, but there are no significant material discoveries.

As of December 2021, there is one active permit for exploration of oil and gas in the offshore zone of the Black Sea – Block 1-21 Khan Asparuh; the exploration of Block 1-14 Khan Kubrat was completed in 2021 but there was no material discovery. The two blocks are situated in the exclusive economic zone of Bulgaria in the Black Sea. In 2021, the tender procedure for the exploration of another offshore Block 1-26 Tervel was cancelled due to no candidates.

F. Renewable energy

F.1 Renewable energy

Renewable energy is regulated by the Energy from Renewable Sources Act ("RES Act"), which implements a substantial part of the Renewable Energy Directive. The RES Act envisaged favourable treatment for producers of renewable and alternative energy sources mainly through guaranteed access to the network, preferential feed-in tariffs, and long-term Power Purchase Agreements ("PPAs").

Currently, the end suppliers purchase the electricity from new RES producers under a preferential feed-in tariff only for small roof installations up to 30kW. The preferential feed-in tariff is set by the Regulatory Commission on an annual basis.

Regarding existing RES projects with installation of 500kW and above, the long-term PPAs and the guaranteed feed-in tariffs were replaced with Contracts for Premium ("CfP") concluded between the Electricity System Security Fund and the producers. Under the CfP support scheme, the producers must sell all electricity produced at the market price on the IBEX. The producers are compensated for the difference between the market price and the repealed feed-in tariff with a premium received by the Security of the Electricity System Fund. The premium is established by the Regulatory Commission for each price period (12 months).

F.2 Renewable pre-qualifications

Bulgaria has not introduced an auction-based mechanism for support of RES projects.

F.3 Biofuel

Under the provisions of the RES Act, importers, producers, and end suppliers of liquid fuels for transportation must offer to the market petroleum-based fuels blended with biofuels at a certain percentage ratio. The relevant ratio is set to increase through consecutive periods. Fuel for diesel engines must contain a minimum of 6% biodiesel, and from 1 April 2019 at least 1% of the biodiesel must be biofuel from new generation. As of 1 March 2019, the minimum content of bioethanol or ethers produced from biomass in fuel for petrol engines must be a minimum of 9%.

G. Climate change and sustainability

G.1 Climate change initiatives

Under the Integrated Plan for the Energy and Climate 2021 – 2030, Bulgaria has set a goal to increase the share of RES in the gross final energy consumption to 27.09% by 2030. It is also expected that Bulgaria will increase the net installed capacity of RES with 2,645MW. The forecast is that most of the new installations will be PV plants due to the rapid development of the technology and decreasing investment costs. However, the Government has not introduced any new concrete incentives in the Bulgarian legislation that will facilitate the development of new RES plants. The economic feasibility of new projects will therefore depend mostly on the market conditions and not on Government support schemes.

In accordance with the Energy Strategy, it is planned that the guarantees of origin (documents issued by the Sustainable Energy Development Agency evidencing that the respective energy is produced from RES) will be unified with the European Energy Certificate System. Therefore, market participants will be able to trade the guarantees of origin on the European markets. Further, in order to ease the administrative burden for investors, the Government intends to set up a one-stop shop for providing information and assistance in obtaining the necessary permits for the development of the plant.

In February 2021, the Bulgarian Energy Efficiency Act was also amended, implementing the requirements of Directive (EU) 2018/2002 of the European Parliament and of the Council amending the EE Directive. Bulgaria continues with the application of both alternative policy measures (fulfilled by the Government) and energy efficiency obligation schemes for private energy suppliers. The new energy efficiency obligation scheme for the period 2021 – 2030 applies to:

- electricity suppliers with annual deliveries to end clients over 20GWh;
- heating suppliers with annual deliveries to end clients over 20GWh;
- natural gas suppliers with annual deliveries to end clients over 10GWh;
- liquid fuel traders with annual deliveries to end clients over 2,000 tonnes; and
- solid fuel traders with annual deliveries to end clients over 13,000 tonnes.

The obliged entities must implement energy efficiency measures that create energy savings in the end consumption in accordance with their annual individual targets.

G.2 Emission trading

The legal framework for emission trading is set out in the Climate Change Mitigation Act ("CCMA") adopted in March 2014 and in a number of regulations, through which the provisions of EU ETS Directive have been implemented.

The Republic of Bulgaria is a participant in the EU Emission Trading Scheme ("EU ETS"). The Minister of Environment and Water is appointed as the auctioneer under Article 22 of the GHG Emissions Allowances Regulation. All auctions for quotas for GHG emissions are conducted in accordance with the GHG Emissions Allowances Regulation. The following participants can offer directly at auctions:

- aviation and installation operators under the GHG Emissions Allowances Regulation;
- investment brokers licensed according to the Bulgarian Markets of Financial Instruments Act;
- banks licensed under the Bulgarian Credit Institutions Act;
- associations of aviation and installation operators when acting as an agent of their members; and
- companies owned by the state or administrative authorities exercising control over the operators under the GHG Emissions Allowances Regulation.

In addition to the EU ETS, the CCMA envisages a national scheme for green investment which operates through the National Trust Ecofund ("NTE"). The NTE manages funds provided directly by the state budget, including under the Debt-for-Environment and the Debt-for-Nature swaps. Funds may also be generated via the Assigned Amount Units (AAUs) international trade deals, the sale of greenhouse gas emissions quotas for aviation activities, as well as by other environmental protection agreements between the Republic of Bulgaria and international or local financing sources. The NTE is responsible for the selection of projects that will be financed, concluding contracts with beneficiaries, and monitoring the correct performance of the project.

G.3 Carbon pricing

In addition to the EU ETS and energy efficiency obligations, the Bulgarian legislation provides for monetary sanctions in case of breaches.

Under the CCMA, the sanctions for operators of installations and aviation operators which do not fulfil their GHG quota obligations are in the amount of about €100 per tonne GHG multiplied by the European consumer price index for the respective year published on the Eurostat website.

Under the Energy Efficiency Act, if the obliged entity does not fulfil its obligation for energy savings under the EEOS, sanctions may be imposed in the amount between about €2,500 and €250,000 depending on the severity of the violation.

G.4 Capacity markets

For the purposes of ensuring the security of the energy system, the operator of the transmission network ("ESO") concludes transactions for ancillary services with local and foreign electricity providers. Ancillary services are all services necessary for the operation of the electricity system such as voltage regulation, frequency regulation, and slow reserves (capacities that remain available and are used in case of a deficit). ESO purchases ancillary services on a competitive market principle through auctions.

H. Energy transition

H.1 Overview

One of the main issues towards the path to zero-carbon energy sector is the dependence of Bulgaria on the coal powered thermal power plants to meet its energy needs. Considering the EU goals for decarbonisation and RES development, it is unclear whether Bulgaria will be able to continue to rely on its local coal stocks and at what cost. Bulgaria must therefore pursue all available avenues for smooth transition out of the coal dependence, including participation in the EU programmes for restructuring of the coal regions and diversification of the supplies of natural gas which has the potential to be a transition fuel in the race to net-zero.

The Integrated Plan outlines numerous measures that Bulgaria intends to implement in the transport, industry, waste, and energy sectors. It is envisaged that Bulgaria will support the use of electric vehicles, improve the energy efficiency of industrial installations and buildings, and gradually increase the share of RES in the energy mix.

H.2 Renewable fuels

Hydrogen

One of the key elements of the Bulgarian Energy Strategy will be the transformation of Bulgaria's gas infrastructure so that it can transport not only natural gas but new green fuels such as hydrogen.

Under the Energy Act, installations that use green hydrogen for production of electricity and are commissioned after 1 January 2021 do not owe a fee to Energy System Security Fund in the amount of 5% of their monthly revenue.

H.3 Carbon capture and storage

Carbon capture and storage is regulated by the Geological Storage of Carbon Dioxide Act ("CCS Act") effective as of 17 February 2012. Both the exploration permit and the storage permit are to be issued by the Minister of Energy. The Council of Ministers is in charge of the state policy on carbon storage and determines the sites that can be used for carbon storage facilities and also bans such developments in certain parts of the country.

The CCS Act sets a number of requirements concerning applications for an exploration or storage permit that relate to the technical capacity and financial means to develop and operate such a project. The procedure for granting a permit is initiated with an order of the Minister of Energy either on discretion of the administration or on request of private investor. All permits issued must be published in the State Gazette and registered in specialised maps. The rights granted with the permit cannot be transferred by the holder to a third party. A storage permit is issued for a particular site for a period of up to 30 years.

The permits are granted following a competitive procedure and coordination with the ministers in charge of national security, environmental protection, and cultural heritage. An exemption to this rule applies to a holder of an exploration permit, provided that the exploration has been successful.

No projects for the capture and storage of carbon dioxide have been realised yet in Bulgaria.

H.4 Oil and gas platform electrification

Bulgaria has not adopted any incentive measures for the electrification of offshore oil and gas platforms.

H.5 Industrial hubs

In March 2021, Bulgaria adopted the new Industrial Parks Act ("IPA"). The purpose of the new law is to ensure investment in manufacturing activities within industrial parks, to promote innovations, and to foster scientific research for the development of high-tech products.

IPA regulates the procedures for establishment, construction, and operation of industrial parks. Industrial parks may be owned by the state, the municipalities or by private investors. The Council of Ministers and the respective municipalities may adopt stimulus measures for the development of industrial parks such as faster administrative services, preferential fees, and local taxes, etc. The Ministry of Economy keeps a register of the established industrial parks whereby potential investors may find an overview of the park's characteristics and the conditions for developing business activities.

H.6 Smart cities

As of December 2021, the Government has not adopted any explicit legislative framework for smart cities. The local mobile operators are in the early stages of developing 5G networks which will be the basis for the introduction of smart city infrastructure.

I. Environmental, social and governance (ESG)

Although Bulgaria has suitable weather conditions for the development of renewable energy, there are some objective restrictions in specific areas where no renewable energy facilities may be constructed. The areas along the boundaries of protected sites within the Natura 2000 network are of concern, where the construction of wind farms is prohibited. Bulgaria has also designated 234 Sites of Community Importance for the conservation of the natural habitats of wild flora and fauna and 120 Special Protection Areas for the conservation of wild birds. Bulgaria holds one of the first places in Europe in terms of protected areas based on the size of its territory, so new projects often face challenges arising from the environmental legislation.

The potential closure or restrictions imposed on the thermal power plants ("TPP") and the related coal extraction industry may lead to a significant rise in the unemployment rate of certain regions where the TPPs play a major role in the local economy.

Energy law in Croatia

Recent developments in the Croatian energy market

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On 1 January 2023, Croatia introduced the Euro as its official currency and joined the eurozone.

New energy sector development strategy of croatia until 2030

In line with the EU climate and energy targets for 2030, Croatia's Low-Emission Development Strategy for the period to 2030, with an outlook to 2050 (*Strategija niskougljičnog razvoja Republike Hrvatske za razdoblje do 2030. godine s pogledom do 2050. godine*) ("LEDS") was adopted on 2 June 2021; the EU 2030 targets are a 40% reduction in greenhouse gas ("GHG") emissions from 1990 levels, a 32% share for renewable energy in the energy mix, and a 32.5% improvement in energy efficiency. The LEDS is a comprehensive economic, developmental, and environmental strategy. Its aim, through innovation, transfer of advanced technologies, and significant structural changes in all sectors, is to boost the growth in industrial production, development of new activities, economic competitiveness, and job creation.

In terms of Croatia's energy sector, the most significant document is a new national Energy Sector Development Strategy to 2030, with an outlook to 2050 (*Strategija energetskog razvoja Republike Hrvatske do 2030. s pogledom na 2050. godinu*), which was adopted on 28 February 2020. This strategy marks a further step towards a low carbon energy sector and represents a wide variety of energy policy initiatives with the aim of strengthening security of energy supply, reducing energy loss, increasing energy efficiency, reducing dependency on fossil fuels, increasing domestic production and the use of renewable energy sources ("RES"). Although one of the main goals of the new strategy is to increase renewable electricity generation capacities, natural gas should also have a significant role in the transition towards a low-emission economy.

Under the strategy, the integrated National Energy and Climate Plan ("NECP") is the key implementation document from 2021 to 2030 and defines the implementing measures that are necessary for the achievement of these objectives. Croatia notified its draft NECP to the European Commission ("Commission") in December 2018. Following its assessment and Commission recommendations on the draft NECP, the final plan was submitted by Croatia by the end of 2019.[1]

Croatia has set a 2030 target for GHG emissions not covered by the EU Emissions Trading System (non-ETS) at -7% compared to 2005. The national RES target is set at an ambitious target of 36.6% of energy from renewable sources of the gross final consumption of energy in 2030. Most of the increase in renewable energy generation is expected in the electricity sector (with a 63.8% share of RES in gross final electricity consumption by 2030), with hydropower contributing the largest share. Increased electricity production in solar (photovoltaic) ("PV") and wind energy is expected to provide an additional contribution to overall renewable electricity generation.

According to Croatia's Resilience and Recovery Plan for the period 2021-2026 (*Nacionalni plan oporavka i otpornosti*) ("RRP"), which was in adopted in July 2021, Croatia aims to have at least 1,500MW of new renewable power capacity until 2025 and more than 2,500MW until 2030.

Additional efforts are necessary in the heating and cooling sector (with a 36.6% share of RES in heating and cooling by 2030), but also in the transport sector, where the respective 2020 and 2030 targets of 10% and 14% of energy from RES may not be met. Croatia aims at reaching a 14% share of RES in the transport sector by 2030, mainly from biofuels. Croatia also plans to continue activities of analysing geothermal potentials and initiating the launch of bidding procedures to select the most suitable bidder for the exploration of geothermal waters for energy purposes.

In terms of energy security, the NECP identifies a need for diversification of natural gas supply routes by constructing the liquefied natural gas ("LNG") terminal on the island of Krk and for an increase of gas storage capacity, further exploitation of domestic hydrocarbon deposits in Slavonia and the Dinarides, and gas deposits in the Southern Adriatic.

Croatia's Hydrogen Strategy for the period from 2021 until 2050, was formally adopted on 25 March 2022. Under the RRP, the objective is to install at least 10MW of renewable hydrogen electrolysers and six hydrogen refuelling stations by 2026 in Croatia. Croatia's Hydrogen Strategy sets more ambitious goals, ie to install at least 70MW of renewable hydrogen electrolysers and 15 hydrogen refuelling stations by 2030, as well as to install a total of 2750MW of renewable hydrogen electrolysers and 100 hydrogen refuelling stations by 2050.

Government support package to offset rise in energy prices

Currently, high and volatile energy prices continue to be of growing concern in Croatia. To this end, in February 2022, the Government launched a package of energy price measures worth HRK4.8 billion (€640 million) aimed to offset the impact of rising energy prices on households, businesses, and socially vulnerable groups. The government measures, with effect from 1 April 2022, will include the capping of the growth of electricity prices to 9.6% and the increase in gas prices to 20%. Furthermore, the Government will permanently lower the value added tax ("VAT") rate on gas and heating energy from 25% to

13%, and temporarily cut the VAT rate on gas to 5% from 1 April 2022 until 31 March 2023.

In September 2022, the Government adopted the Regulation on Eliminating Disturbances in the Domestic Energy Market (*Uredba o otklanjanju poremećaja na domaćem tržištu energije*),[2] with effect from 9 September 2022. Due to disruptions in the domestic energy market, this Regulation regulates:

- special measures for electricity trade, the method and conditions of price formation for certain categories of electricity and thermal energy customers, supervision over the application of set prices, and special conditions for performing energy activities. The special measures are temporary and set for the period from 1 October 2022 until 31 March 2023.
- special measures for gas trade, the method and conditions of gas price formation, ensuring conditions for the security of gas supply for certain categories of gas buyers, and special conditions for performing the gas energy activities. The special measures are temporary and set for the period from 15 September 2022 until 31 March 2024.
- the obligation of a natural gas producer INA to sell a total natural gas produced in Croatia to state-owned electricity company HEP in order to ensure gas supplies and increase the availability of natural gas in Croatia, in the period until 31 March 2024.

In addition, Croatia has implemented Council Regulation (EU) 2022/1854 of 6 October 2022 as an emergency intervention to address high energy prices, in relation to the measures for the application of the cap on market revenues and distribution of surplus congestion income revenues to final electricity customers, into national law through the Regulation on Emergency Intervention Act to Address High Electricity Prices,[3] which came into effect on 1 January 2023. On 26 January 2023, the Croatian Energy Regulatory Agency (HERA) adopted and published on its website the implementing guidelines,[4] which came into effect on 27 January 2023. This Regulation covers the wholesale electricity market in accordance with the Electricity Market Act.

Market revenues of producers obtained from the generation of electricity from the following sources: wind, solar (solar thermal and solar photovoltaic), geothermal energy, hydropower without reservoir, biomass fuel (solid or gaseous biomass fuels), excluding biomethane, waste, nuclear energy, lignite, crude petroleum products, peat, are capped to a maximum of 180 EUR per MWh of electricity produced. The cap on market revenues targets all the market revenues of producers and, where relevant, intermediaries participating in electricity wholesale markets on behalf of producers. This is regardless of the market timeframe in which the transaction takes place and of whether the electricity is traded bilaterally or in a centralised marketplace.

Significant energy infrastructure projects in Croatia

According to the Ten-Year Network Development Plan (TYNDP 2022 to 2031) of the Croatian Transmission System Operator ("HOPS"), major upgrades and expansion of the transmission grid are needed and planned in the upcoming period 2022-2031. Due to the planned large-scale integration of wind and solar (PV) energy, the significant increase in investments in the grid upgrades and construction of grid connections is required and planned, amounting up to HRK9.3 billion (around €1.2 billion).

According to the Ten-Year Network Development Plan of the Gas Transmission System of PLINACRO ("TYNDP 2021 to 2030"), the current gas supply forecasts indicate the need for further transmission capacity and significant investment in the construction of new parts of the gas transmission system with regard to its integration into new strategic supply projects. Therefore, the two most important projects under the TYNDP are the LNG terminal on the Island of Krk in the North Adriatic and the Ionian-Adriatic Pipeline ("IAP").

LNG terminal project

Perhaps one of the most important projects in the gas sector concerns the construction of the floating LNG terminal on the Island of Krk in the North Adriatic, with a capacity of up to 2.6 billion cubic metres and its connecting gas pipeline Omišalj-Zlobin, which was put into commercial operation on 1 January 2021. The LNG terminal consists of the floating storage and regasification unit ("FSRU") and onshore part of the terminal. The LNG terminal with connecting and evacuation pipelines towards Hungary and beyond has received Project of Common Interest ("PCI") status from the Commission under the Connecting Europe Facility ("CEF") funding instrument. LNG Hrvatska d.o.o. ("LNG Croatia") (with HEP and PLINACRO each holding 50% of the equity shares) is the LNG facility operator.

The LNG terminal, which now provides a new supply route to Croatia, has increased the level of diversification of gas supply sources, and has increased competitiveness on the market and the security and diversification of natural gas supply in Central and South-Eastern Europe. The entire terminal's long-term capacity has been booked until 2030. Contracts on the use of the terminal have been signed with the INA, HEP, MET Croatia Energy Trade, MVM CEEnergy Croatia, and PPD companies.

To increase the energy security and gas supply, in August 2022, the Government has adopted a decision on construction of the Zlobin – Bosiljevo gas pipeline and expanding the capacity of the LNG terminal up to 6.1 billion cubic meters. The total investment amounts to €180 million, out of which €155 million has been marked for the extension of the PLINACRO gas transmission system, and €25 million for the expansion of the terminal's capacity.

IAP project

The IAP project intends to connect the Croatian and Albanian pipeline system with the Trans Adriatic Pipeline ("TAP") (TAP is part of the EU-designated Southern Gas Corridor with a length of 800 kilometres ("km"), running from Greece to Italy, via Albania and the Adriatic Sea). The total gas pipeline length from Croatia (Ploče) to Albania (Fieri) is 540km and has an annual pipeline capacity of 5 billion cubic metres per annum. This is a strategically important project, the implementation of which will enable the creation of a new energy corridor for the South-East Europe region, with the aim of establishing a new supply of natural gas from new sources, ie the Caspian and Middle Eastern regions.

In December 2022, gas transmission system operators of Slovenia (Plinovodi), Austria (Gas Connect Austria), and Croatia (PLINACRO) have signed the Memorandum of Understanding and agreed to continue the cooperation as regards the energy infrastructure development in accordance with the revised TEN-E Regulation[5]. The special attention is given to the infrastructure projects connecting the transmission systems at cross-border points, as well as cooperation regarding the submission of the projects of common interest (PCI projects). Under the memorandum, the operators agreed that the expansion and development of the pipeline infrastructure for the transport of hydrogen among Croatia, Slovenia, and Austria, depending on the availability of hydrogen, is of mutual interest. In addition, they agreed on the main guidelines for coordinated submission of the project of mutual interest through the exchange of information and data on the potential supply sources of hydrogen to be transported in the direction Croatia - Slovenia - Austria and related to the expected development of the maximum technical capacity of hydrogen transmission, and delivery pressure, over the course of time, at each interconnection point operated by individual operators.[6]

Peak storage facility Grubišno Polje project

The most important project of strategic interest for the gas storage operator PODZEMNO SKLADIŠTE PLINA d.o.o. ("PSP") in the period 2022-2026, concerns the construction of a new underground gas storage facility located at the gas field Grubišno Polje ("UGS Grubišno Polje"). The UGS Grubišno Polje is planned as a storage facility with a working volume of minimum 25 million cubic meters, with a maximum injection capacity of up to 1.4 million cubic meters per day and a maximum withdrawal capacity from 1.7 to 2.4 million cubic meters per day with a possibility of multiple injection and withdrawal circles during winter season. Its primary task will be to ensure peak withdrawal capacities during the winter season, but also to provide support during gas withdrawal from the seasonal underground gas storage facility PSP Okoli. This will increase the flexibility of the Croatian gas system and the security of gas supply.[7]

New electricity market act in force from October 2021

The recast Electricity Directive has been implemented into national law by provisions of the new Electricity Market Act (*Zakon o tržištu električne energije*), which came into effect on 22 October 2021. The new law sets out common rules for production, transmission, distribution, storage and supply of electricity, together with rules on consumer protection, with the aim to create an integrated, competitive, flexible, fair, and transparent electricity market of the Republic of Croatia as part of the electricity market of the European Union.

The law seeks to ensure acceptable and transparent energy prices and costs for final customers, a high degree of security of supply and a smooth transition to a sustainable energy system with low carbon emissions.

The law, among other things, lays down rules relating to the organisation and functioning of the electricity sector of the Republic of Croatia, in particular rules on empowerment and protection of final customers, open access to the integrated electricity market, third party access to electricity transmission and distribution infrastructure, requirements for unbundling systems and rules on the independence of the regulatory authority.

The law introduces new market participants, such as active customer and citizen energy communities to enable final customers to directly participate in the production, consumption, or sharing of electricity. In addition, the law provides for the introduction of new energy activities such as aggregation, energy storage, organisation of citizen energy communities, and closed distribution systems. The final customer can independently, or through aggregation, participate on an equal basis on all the electricity markets.

One of the key amendments introduced by the new law, concerns the introduction of an obligatory public tender for the issuance of the energy approval permit for the construction of new generating installation or energy storage facility (see Overview of the legal and regulatory framework in Croatia, section A.5). As regards the existing projects under development, the new law provides for a special permitting regime under which project developers that have obtained specific permits required for development of a particular site (ie location permit or grid connection agreement or grid connection permit or EIA decision) were required until 19 January 2022, to submit to the ministry competent for energy, a request with expression of interest for public tender for the issuance of an energy approval permit. In February 2022,[9] the ministry competent for energy announced it had received a total of 216 requests with expressions of interest for conducting a public tender for the issuance of energy approval, with a total planned connection capacity of 5953.5MW, out of which most are solar (around 3800MW) and wind power plants (1760MW). In October 2022, the ministry published a list of rejected RES projects and applicants with a total rejected planned connection capacity of 2479MW. The administrative procedure related to these projects and assessment of documentation submitted is time-consuming and still pending before the ministry. Although the ministry is required by law to conduct a public tender for these projects, the law does not lay down a specific deadline by which the ministry must carry these tenders. Due to limited administrative capacities of the ministry, only few public tenders were launched up to now.[10]

Most secondary legislation that is required to ensure the full and effective implementation of the recast Electricity Directive and recast Electricity Regulation, remains to be adopted in 2023.

Reform of RES and cogeneration legal framework

In December 2021, two key regulatory changes took place that will have important implications for the future development of the Croatian renewable energy market.

Firstly, on 9 December 2021, the European Commission approved the €783 million Croatian state aid scheme to support the production of electricity from RES. The new scheme will enable Croatia to support a total capacity of 2,010MW of renewable electricity production from various technologies (wind, solar, hydro, biomass, biogas, and geothermal power plants).

Secondly, on 23 December 2021, the new Act on Renewable Energy Sources and High-Efficiency Cogeneration (*Zakon o obnovljivim izvorima energije i visokoučinkovitoj kogeneraciji*)[11] entered into force. The key amendments are centred around the introduction of a renewable energy auction support mechanism.

The RES support mechanism is introduced by way of market premiums which are going to be paid to RES producers on top of the (reference) electricity market price for a period of 12 years. The premium will be set through a competitive bidding process (auction). The new support scheme provides for a total budget of €783 million for support payments until 2023 (see Overview of the legal and regulatory framework in Croatia, section F.2).

The long-awaited first auction for large-scale wind and solar power plants was launched in June 2022. In July 2022, a decision on the selection of the winning bidders for the award of market premium was published by the Croatian Energy Market Operator (HROTE). The available auction quota was set at 638MW, but HROTE received bids for only 150 MW in total.

The implementing by-laws that will ensure full and effective implementation of new support schemes for RES and high-efficiency cogeneration plants until 2030 are yet to be adopted.

Both the new Electricity Market Act and RES Act seek to remove administrative barriers and simplify administrative procedures to improve uptake of RES in the electricity sector.

According to the new RES Act, the key amendments, inter alia, include:

- The acquisition of the status of a preferential energy producer for production plants using RES and/or high-efficiency cogeneration will be regulated by new Regulation on using RES and high efficiency cogeneration (which is expected to be adopted in the first quarter of 2023).
- The Government will set the quota for a RES support scheme until 2030 by regulation (to be adopted in the upcoming period).
- The Croatian Energy Market Operator (HROTE) shall conduct an auction for the award of market premiums (FIP) at least once every three years, and an auction for the award of power purchase agreements ("PPA") at a guaranteed purchase price at least once every year (for small RES projects of up to 500 kW) in case of the available quota.
- The auction is not considered as an administrative procedure. However, the award decision can be challenged in an administrative dispute proceeding before the High Administrative Court of the Republic of Croatia.
- The Ministry of Economy and Sustainable Development (MGOR) has been designated as a contact point for the entire administrative permitting process for RES projects development. Upon the request of investor/project holder, the ministry shall provide guidance during the entire permitting procedure related to the relevant administrative permits for construction and operation of RES plants as well as the procedure for connection to the grid. The investor/project holder can during the entire permitting procedure keep informed the ministry and submit all required documents in digital form as well. The ministry shall guide the applicant during the permitting procedures, provide all required and allowed data and, if appropriate, include other administrative and public authorities.
- The permit-granting procedure for RES plants shall not exceed two (2) years before the first-instance public authority as of submission of a complete request including all relevant procedures of other competent authorities, except for procedures under applicable environmental law. In exceptional cases or due to force majeure, this two-year period can be extended by up to one (1) year.
- A manual of permitting procedures for the construction of RES production plant shall be prepared by the Croatian Energy Market Operator (HROTE), in cooperation with the Ministry of Economy and Sustainable Development (MGOR), the Croatian Energy Regulatory Agency (HERA), the TSO and the DSO and the Ministry of Physical Planning, Construction and State Assets and made available on the website of MGOR (to be drafted in the upcoming period), etc.

INA-MOL dispute

INA-INDUSTRIJA NAFTE d.d. ("INA") is the key market player in the Croatian oil and gas industry; INA is a vertically integrated company with MOL Hungarian Oil and Gas Plc ("MOL"), which holds 49.08%, and the Government, which holds 44.84%, is its biggest shareholders.[12] Under the Shareholders' Agreement 2009, MOL gained operational control of INA. Although the Shareholders' Agreement stipulates that the Government should take over the gas trading business of INA (ie the import business of PRIRODNI PLIN) by December 2010, this issue remained unresolved during the official negotiations between the Government and MOL, which were discontinued. Consequently, two arbitration procedures in connection with the INA-MOL dispute were initiated. At the end of November 2013, MOL initiated the arbitration procedure under ICSID rules against the Government under the Energy Charter Treaty. In January 2014, the Government initiated arbitration under UNCITRAL rules in Geneva to annul the 2009 Amendments to the Shareholders' Agreement and the Gas Master Agreement (and its First Amendment).[13] In June 2014, the former Croatian Prime Minister was sentenced to imprisonment for taking a bribe from MOL in 2008 in exchange for securing MOL's dominant position in INA. However, in July 2015, the Croatian Constitutional Court annulled the verdict and ordered a retrial. In December 2016, UNCITRAL dismissed Croatia's claims based on bribery, corporate governance, and MOL's alleged breaches of the 2003 Shareholders' Agreement. In October 2021, the Croatian Supreme Court confirmed the first instance verdict by which the former Croatian Prime Minister was sentenced to imprisonment for taking a bribe from MOL's CEO. In July 2022, the ICSID tribunal upheld MOL's claim and ordered Croatia to pay US$236 million plus interest to MOL after rejecting allegations that the MOL's CEO paid bribes to the former Croatian Prime Minister, whereas the rest of the MOL's billion-dollar claim was rejected.

By the end of 2016, due to the arbitration tribunal decision, the Croatian Prime Minister announced that the Government plans to buy back MOL's share in INA and that this should be financed by selling 25% shares of the 100% state-owned electricity company HEP in an initial public offering. However, the idea that the buyback of MOL's share in INA should be financed by selling minority shares (25 minus 1) of HEP has not received political support from the key Government coalition partners and main opposition parties in Croatia. Although the Government set up a special governmental advisory committee for the buyback of INA in January 2017, no concrete sale models and details of the potential sale process are available to date. The Government is still in the process of exploring the possibilities and best models to ensure that the buyback of MOL shares in INA will not increase external public debt. It is not therefore excluded that the Government will complete this process through finding a new 'strategic partner'; however, it is difficult to predict whether the Government will kick off this transaction at all. On 31 July 2019, the Government announced that it had selected the international investment bank Lazard as a new consultant on the buyback of MOL's shares in INA. At the end of October 2021, the Croatian Supreme Court upheld the guilty verdict of six years against former Croatian Prime Minister for taking a bribe from a MOL executive director, who was sentenced to two years' imprisonment. At the end of 2021, negotiations on the buyback of MOL's share in INA were put on hold. In November 2022, the Government requested the drafting of a comprehensive legal opinion on the nullity of the agreements with MOL and the payment of damages based on the ICSID ruling from July 2022. In January 2023,[14] the Government made available to public the legal opinion prepared by Croatian law professors and the State Attorney's Office, which opined that the judgement of Croatian courts in case of the former Prime Minister and MOL's CEO does not have legal effects in relation to agreements between Croatia and MOL. The Croatian courts do not have jurisdiction to decide upon the Croatia's claim against MOL, and to determine the nullity of these contracts. Finally, the opinion states that it is prudent to settle the damages awarded to MOL under the ISCID arbitration ruling, in accordance with international obligations.

Endnotes

1. See National Energy and Climate Plan for the Republic of Croatia for the period 2021-2030 from December 2020. Available at www.mingor.gov.hr/UserDocsImages/UPRAVA%20ZA%20ENERGETIKU/Strategije,%20planovi%20i%20programi/hr%20necp/Integrated%20Nacional%20Energy%20and%20Climate%20Plan%20for%20the%20Republic%20of_Croatia.pdf.
2. Official Gazette of the RoC 'Narodne Novine' nos. 104/22, 106/22 and 121/22.
3. Official Gazette of the RoC 'Narodne Novine' no. 156/22.
4. Guidelines for the Implementation of the Regulation on Emergency Intervention Act to Address High Electricity Prices (*Upute za provedbu Uredbe o Zakonu o hitnoj intervenciji za rješavanje pitanja visokih cijena električne energije*) of HERA from 26 January 2023. Available at: www.hera.hr.
5. Regulation (EU) no. 2022/869 of the European Parliament and of the Council of 30 May 2022, on guidelines for trans-European energy infrastructure, amending Regulations (EC) No 715/2009, (EU) 2019/942 and (EU) 2019/943 and Directives 2009/73/EC and (EU) 2019/944, and repealing Regulation (EU) No 347/2013 (OJ L 152, 3.6.2022, p. 45).
6. Press release of PLINACRO of 16 December 2022. Available at: www.plinacro.hr.
7. Further information and project description is available on the website of PSP at: www.psp.hr/peak-storage-facility-grubisno-polje.
8. Official Gazette of the RoC 'Narodne Novine' no. 111/21.
9. Available at: www.mingor.gov.hr.
10. Decisions on launching public tender for the issuance of energy approval are published in the Official Gazette of the RoC and on the website of MGOR. Available at: www.mingor.gov.hr/o-ministarstvu-1065/djelokrug/uprava-za-energetiku-1999/energetska-odobrenja/8946.
11. Official Gazette of the RoC 'Narodne Novine' no. 138/21.
12. INA Group chart is available on the website of INA at www.ina.hr.
13. Further information on the negotiations on INA's shareholding is available on the website of MOLGROUP at www.molincroatia.com/negotiations.
14. Press release of Croatian Government of 31 January 2023. Available at: www.vlada.gov.hr/vijesti/pravno-misljenje-radne-skupine-pravnih-fakulteta-i-misljenje-dorh-a-o-ugovorima-hrvatske-i-mol-a/37730.

Overview of the legal and regulatory framework in Croatia

A. Electricity

A.1 Industry structure

Nature of the market

Croatia's accession to the EU on 1 July 2013 has brought and continues to bring about substantial changes to the country's energy sector. However, the electricity generation, distribution, and supply sectors are still dominated by the vertically integrated HEP Group, which is wholly owned by the Croatian state. As the national electricity utility, HEP Group is engaged in electricity generation, transmission and distribution, electricity supply, and trade as well as in other energy sectors, such as thermal energy and natural gas. Over the last decade, HEP Group, consisting of the parent company HEP d.d. ("HEP") and its affiliated companies,[1] underwent a restructuring process to ensure effective unbundling between regulated activities (transmission and distribution) and non-regulated activities (generation and supply). All transmission and distribution networks are owned (up to the metering point) by HEP.

HEP-OPS (*HEP Operator prijenosnog sustava d.o.o.*), which was renamed the Croatian Transmission System Operator (*Hrvatski operator prijenosnog sustava d.d.*) ("HOPS") in July 2013, is the only transmission system operator ("TSO") for Croatia, and HEP-ODS is the distribution system operator ("DSO").

The main generation facilities are owned and operated by HEP Group companies (about 75% of the total electricity generation capacity).[2] Further, a certain number of industrial power plants are connected to the transmission or distribution network. There are also a few privately owned power plants (wind power plants, small hydropower plants, thermal power plants, and solar power plants). In 2021, the share of renewable energy sources (RES)in total electricity generation reached 23.1% (without large hydropower plants).[3] The wind and hydropower accounted for over 63% of the total electricity generated from RES (14.5% and 48.5%, respectively). The remaining electricity came from fossil fuels (28.5%), biomass (4.1%), biogas (2.8%), solar power (0.9%) and geothermal power (0.5%).[4] At the end of 2021, Croatia reached a total installed capacity for electricity generation of 5,534MW (2,202MW of hydro power plants, 2,049MW of thermal power plants, and 981MW of wind power plants), out of which 3,485MW (ie 63%) are renewable-energy power[5] plants.

Customers have been free to choose their electricity supplier since 1 July 2008. However, to date, the key electricity suppliers in Croatia are part of the HEP Group: HEP Opskrba d.o.o. is a major supplier, and HEP ELEKTRA d.o.o. provides the public services of being the universal supplier of electricity (for household customers) and supplier of last resort (for business customers who are left without a supplier). The Croatian retail electricity market is fully opened, and prices are not regulated (except for last resort electricity supply). However, the electricity market continues to be highly concentrated with HEP Group companies holding about 90% of the supply market.[6]

Key market players

The key market players in the electricity sector are part of the vertically integrated HEP Group. The HEP Group has some 4,000MW of installed capacity for electricity generation. HEP-Proizvodnja d.o.o. operates 26 hydropower plants and seven thermal power plants (oil-fired, gas-fired, and coal-fired). HEP is a co-owner of the Krško nuclear power plant in Slovenia (and 50% owned by Gen Energija d.o.o.).

Regulatory authorities

The energy sector (comprising electricity, RES, thermal energy, gas, biofuel, oil, and oil derivatives) falls under the competence of the Ministry of Economy and Sustainable Development (*Ministarstvo gospodarstva i održivog razvoja*) ("MGOR").

The Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*) ("HERA") is the national energy regulatory authority regulating and supervising energy activities in the energy sector. HERA can:

- grant and revoke licences (eg, licences for carrying out energy activities, decisions on granting eligible generator status);
- set out the tariff methodologies;
- adopt or approve prices, tariff rates, and fees in accordance with the methodologies and tariff systems;
- issue regulations on network connection fees and for the increase in connection power;
- issue opinions or approvals regarding rules and regulations within the energy sector;
- monitor cross-border capacities and congestion management;
- monitor customer protection;
- settle disputes regarding the performance of regulated energy activities; cooperate with ministries and respective state inspectorates; and
- submit requests for initiating administrative court proceedings.

The Croatian Energy Market Operator is the operator of the electricity market (*Hrvatski operater tržišta energije d.o.o.*) ("HROTE").

Legal framework

The key laws related to electricity are the Energy Act (*Zakon o energiji*)[7]) ("ZE"), the Act on the Regulation of Energy Activities

(*Zakon o regulaciji energetskih aktivnosti*)[8] ("ZREA"), and the new Electricity Market Act (*Zakon o tržištu električne energije*)[9] ("ZTEE"). In addition, implementing regulations apply that regulate specific areas of the electricity sector (eg, electricity market organisation, electricity system balancing, tariff systems, allocation and use of cross-border transfer capacities, connection to the power grid, and general conditions for using the network and electricity supply).

For the legal framework on renewable energy and combined heat and power plants, see section F.1.

Implementation of EU electricity directives

The Third Electricity Directive has been implemented into national law by provisions of the ZE and ZREA, both of which came into effect on 8 November 2012, and the old ZTEE, which came into effect on 2 March 2013. The recast Electricity Directive has been implemented into national law by provisions of the new ZTEE, which came into effect on 22 October 2021. However, most secondary legislation, which will ensure the full and effective implementation of the recast Electricity Directive and recast Electricity Regulation remains to be adopted in 2023.

Croatia has opted for the independent transmission operator ("ITO") model, pursuant to which HOPS will belong to the HEP Group but must comply with strict regulatory conditions to ensure effective independence. HOPS' certification process, before HERA, was finalised in January 2016 after obtaining the opinion from the European Commission ("Commission"). In December 2021, the Croatian energy regulatory authority (HERA) approved the draft Ten-Year Network Development Plan with detailed elaboration for the initial three-year and one-year period of HOPS (TYNDP 2022 to 2031).[10]

New investments in the energy sector need to be in line with the Energy Sector Development Strategy of the Republic of Croatia until 2030, with an outlook to 2050 (*Strategija energetskog razvoja Republike Hrvatske do 2030. s pogledom na 2050. godinu*).[11] This was adopted on 28 February 2020, and the core objectives are reduction of greenhouse gas ("GHG") emissions, increase of RES, competitiveness, security of supply, and the sustainable development of the energy sector. In line with the European Green Deal ("EGD") and the Government Regulation, Croatia's Low-Emission Development Strategy until 2030, with an outlook to 2050 (*Strategija niskougljičnog razvoja Republike Hrvatske do 2030. godine s pogledom do 2050. godine*)[12] ("LEDS") was adopted on 2 June 2021, of which the core objective is the sustainable development based on the economy with low GHG emissions and efficient use of resources.

A.2 Third party access regime

The ZTEE provides for non-discriminatory access to transmission and distribution networks. It does so according to the principle of regulated third party access, and pursuant to the regulation on grid connection approval, conditions and deadlines for connection to the power grid, general conditions for network use and electricity supply, connection conditions, the Grid Code for the transmission system and the Grid Code for the distribution system, methodology for determining fees for connection to the power grid, and by ensuring objective and non-discriminatory prices for network use.

HOPS and HEP-ODS can only deny or restrict access on grounds of technical or operational limitations of the network, maintenance works, development of the network, or a threat to human life or property. HOPS and HEP-ODS must provide reasons to network users for denial or restriction of access to the grid. A network user who has been denied or restricted access to the network, or who is unsatisfied with the access requirements, can appeal to HERA for a decision. No appeal can be made against HERA's decision, but the injured party can bring a claim before the competent administrative court.

In line with the new ZTEE, HOPS and HEP-ODS cannot refuse the connection of a new generating installation or energy storage facility on the grounds of possible future limitations to available network capacities, such as congestion in distant parts of the network. Exceptionally, HOPS and HEP-ODS may limit the connected capacity or offer connections subject to operational limitations, in order to ensure economic efficiency regarding new generating installations or energy storage facilities, provided that such limitations have been approved by HERA. New generating installations or energy storage facilities subject to operational limitations in connection capacity in accordance with the rules on congestion management in the transmission network, must bear the costs incurred by the TSO in implementing these operational limitations. HOPS and HEP-ODS are not entitled to refuse a new connection to the grid, on the ground that it would lead to additional costs of creating technical requirements within the network.

The study on the technical solution for grid connection (*elaborat mogućnosti priključenja na mrežu*; "EMP") and final grid connection study (*elaborat optimalnog tehničkog rješenja priključenja na mrežu*; "EOTRP") must be prepared for the purpose of conclusion of the grid connection agreement (*ugovor o priključenju*) and obtaining the grid connection approval (*elektroenergetska suglasnost*). To take part in the public tender for the issuance of the energy approval permit for the construction of new generating installation or energy storage facility, a preliminary opinion of the TSO and/or DSO on possibilities and options for grid connection (*preliminarno mišljenje o EMP-u*) must be obtained from HOPS or HEP-ODS. To determine special conditions for a complex connection to the grid, a decision on acceptability of a final grid connection study (*odluka o prihvatljivosti EOTRP-a*) must be obtained from HOPS or HEP-ODS. The grid connection approval sets out the technical requirements for connection to the grid. Prior to connection to the grid, grid connection approval must be obtained, and the grid use agreement (*ugovor o korištenju mreže*) concluded with HOPS or HEP-ODS. Generally, priority dispatch applies for RES generators who have obtained the eligible generator status (unless such priority delivery significantly impairs the reliability and safety of the grid operation).

Information on the possibilities of connection to the transmission or distribution network are public, to be updated on an annual basis, and must be made available on the website of HOPS and HEP-ODS.[13] HOPS must keep and update an online available list of authorized companies and persons to be engaged with in preparation of a study on technical solution for grid connection and final grid connection study.[14]

The specific procedures are regulated in detail by the following secondary legislation:

- Regulation on Issuance of Electro-Energetic Approvals and Determining Conditions and Deadlines for Connection to the Power Grid (*Uredba o izdavanju energetskih suglasnosti i utvrđivanju uvjeta i rokova priključenja na elektroenergetsku* *mrežu)*[15] with effect from 1 April 2018;

- Ordinance on General Conditions for Using the Network and Electricity Supply (*Pravilnik o općim uvjetima za korištenje mreže i opskrbu električnom energijom*);[16]
- Grid Code for the transmission system of HOPS (*Mrežna pravila prijenosnog sustava*);[17]
- Grid Code for the distribution system (*Mrežna pravila distribucijskog sustava*);[18]
- Rules for Connection to the distribution system (*Pravila o priključenju na distribucijsku mrežu*);[19] and
- Rules for Connection to the transmission system (*Pravila o priključenju na prijenosnu mrežu*),[20] which contain the relevant application forms and template agreements for connection to the transmission system.

Procedures for connection of generating installations to the power grid, in line with the new ZTEE, will be defined in new implementing regulations, which remain to be adopted in the upcoming period.

A.3 Market design

The new ZTEE provides for the following electricity markets: (i) wholesale electricity markets that include the over the counter ("OTC") market and the electricity stock exchange, (ii) retail electricity markets that include electricity supply and aggregation, and (iii) other electricity markets that include balancing market and non-frequency ancillary services market. In practice, wholesale electricity can be traded in the OTC market based on bilateral agreements and on the power exchange CROPEX.

CROPEX is the Croatian Power Exchange (*Hrvatska burza električne energije d.o.o.*), which was established in May 2014[21] and is jointly owned by HROTE and HOPS. In December 2015, HERA designated CROPEX as a nominated electricity market operator ("NEMO") for single day-ahead and intraday market coupling for an initial period of four years. The CROPEX day-ahead market ("DAM") came into operation on 10 February 2016, but in isolated mode (ie, with no market coupling applied). The CROPEX intraday market ("IDM") became operational on 26 April 2017.[22] The launch of the CROPEX IDM in April 2017 marked a major step toward further liberalisation of the Croatian electricity market. The CROPEX IDM meets the legal prerequisites in accordance with the EU CACM Regulation for the implementation of cross-border market coupling of the CROPEX IDM with the neighbouring EU IDMs. From 2018, CROPEX DAM is coupled with the European SDAC market through the Croatian-Slovenian border, and from June 2022, via the Croatian-Hungarian border as well. From 2019, CROPEX IDM is coupled with the European SIDC market via the Croatian-Slovenian and the Croatian-Hungarian borders.[23]

In 2021, the European Energy Exchange (EEX) and CROPEX have agreed to jointly develop a power derivatives market for Croatia. The launch of the Croatian Power Derivatives Market is expected at the end of March 2023.[24]

As regards liquidity, CROPEX is rather a small national power exchange. In 2022, total traded volume on DAM amounted 5,590GWh. According to the Herfindahl–Hirschman Index, CROPEX DAM is a competitive market and provides all its members enough liquidity for their trading activities.[25]

Currently, there are 26 members on CROPEX DAM, of which 23 also participate on CROPEX IDM.[26]

To become CROPEX members and trade on the day-ahead trading platform, a market participant needs to enter into a membership agreement with CROPEX. The prerequisite for the membership is obtaining an energy licence from HERA, entering into a balance responsibility contract with HOPS, and the conclusion of an electricity market participation agreement with HROTE.

Market participants in the wholesale electricity market in Croatia can be divided into: (i) competitive market participants, ie those who trade electricity under market principles, and (ii) regulated market participants responsible for market organisation and network management.

Competitive market participants in Croatia are: (i) generators, (ii) traders and (iii) suppliers. Each market participant must obtain an energy permit for respective energy activity issued by HERA to participate in the market and conclude an electricity market participation agreement with HROTE.

An electricity generator is an energy entity with a licence to produce electricity (see section A.1). A generator is classified either as either (a) an eligible generator (ie a generator who obtained 'eligibility status') or (b) an independent generator.

A trader can only participate in the wholesale market, while the supplier can participate in the wholesale and the retail market. This means that a trader is not allowed to sell electricity to end-users and a supplier can sell electricity to end-users (eg households and business (industry) end customers).

The new ZTEE introduces new market participants, such as active customer and citizen energy communities, to enable final customers to directly participate in the production, consumption, or sharing of electricity. The final customer can independently, or through aggregation participate on an equal basis on all the electricity markets. New market participants also include aggregators, operators of energy storage, and closed distribution system operators.

The four regulated market participants in Croatia are HROTE, CROPEX, HOPS, and HEP-DSO.

Pursuant to the Rules on Electricity Market Organisation (*Pravila organiziranja tržišta električne energije*)[27], the following balancing group (BG) model exists on the Croatian electricity market, which comprises: (i) an ECO balancing group (ECO-BG) (managed by HROTE, and set up to balance RES and cogeneration plants operated by eligible generators), (ii) the market balancing groups (M-BG) (of which members are generators, traders and/or suppliers), (iii) a balancing group of TSO (TSO-BG) (managed by HOPS), (iv) a balancing group of DSO (DSO-BG) (managed by HEP-ODS), and (v) a balancing group of power exchange (PE-BG) (managed by CROPEX).

A.4 Tariff regulation

Under the ZE, HERA, as the national regulatory authority, defines the methodology for tariff systems and is empowered to set tariff rates. In setting or changing tariff rates, an energy undertaking (on whose services the tariffs will be applied) is obliged by the methodology to submit a request for approval to

HERA. In the event that HERA refuses to grant approval, HERA will independently set the tariff rates.

The methodology must be based on justified costs of operation, maintenance, replacement, construction and reconstruction of facilities, and environmental protection, and it must ensure an appropriate return on reasonable investments. Further, the regulation model can be based either on an incentive regulation or some other method of economic regulation. In any case, the tariff regime must be non-discriminatory and transparent.

HERA also defines the methodology for determining fees for connection to the transmission and distribution networks and for increasing capacities.

On the basis of the Methodology for determining tariffs for electricity transmission (*Metodologija za određivanje iznosa tarifnih stavki za prijenos električne energije*)[28] and the Methodology for determining tariffs for electricity distribution (*Metodologija za određivanje iznosa tarifnih stavki za distribuciju električne energije*),[29] in December 2021 HERA set tariff rates for electricity transmission for 2022 (*Odluka o iznosu tarifnih stavki za prijenos električne energije*)[30] and tariff rates for electricity distribution for 2022 (*Odluka o iznosu tarifnih stavki za distribuciju električne energije*),[31] which entered into force on 1 January 2022.

The regulation model is based on the method of approved operating costs. The tariff system is based on the post stamp principle. Network users connected to the transmission network pay only the price for transmission network usage. Network users connected to the distribution network pay the price for distribution network usage as well as the price for transmission network usage.

Either generators or final customers bear the costs of network connections. The new Methodology for Determining Fee for Connection to the Electric Power Network (*Metodologija za utvrđivanje naknade za priključenje na elektroenergetsku mrežu*)[32] sets out the methodology for determining fees for connection of the generator's building or a customer to the transmission or distribution network. However, the (old) Methodology for Determining Fees for Connection to the Electric Power Network of New Users and for Increase in the Connected Load of Existing Network Users (*Metodologija utvrđivanja naknade za priključenje na elektroenergetsku mrežu novih korisnika mreže i za povećanje priključne snage postojećih korisnika mreže*)[33] still applies and shall cease to be valid with entering into force of a new Decision on the unit fee amount for grid connection (*Odluka o iznosu jedinične naknade za priključenje na mrežu*), which remains to be adopted by HERA in 2023.

Following the amendments to the ZTEE, which came into effect on 3 October 2015, electricity supply prices under universal services were deregulated (ie electricity under universal service can only be supplied to household customers). As of 1 January 2017, final customers on the low voltage network receive just one bill, comprising both the electricity bill and the bill for network use.

The ZTEE imposes an obligation on HERA to consult consumer organisations in relation to setting tariffs for the respective electricity activities performed as public services.

Based on the Methodology for determining tariffs for supply of last resort (*Metodologija za određivanje iznosa tarifnih stavki za zajamčenu opskrbu električnom energijom*),[34] as of 1 March 2022, HERA sets out tariff rates on a quarterly basis.

A.5 Market entry

Performance of energy activities

A licence for the performance of energy activities (*dozvola za obavljanje energetske djelatnosti*) is needed to carry out energy activities such as: (i) electricity generation (if generation is over 500kW per power plant),[35] (ii) electricity transmission, (iii) electricity distribution, (iv) the organisation of the electricity market, (v) electricity supply, (vi) aggregation, (vii) electricity trading, (viii) energy storage, (ix) the organisation of citizen energy communities, and (vi) operator of closed distribution systems (see below, Licensing regime). The licence is granted by HERA provided that specified conditions are fulfilled (eg, registration; technical, expert, and financial qualifications; the absence of any criminal record). The period of validity of the licence is subject to the specific activity. The registry of issued licences is available on HERA's website.[36]

The Act on Strategic Investment Projects of the Republic of Croatia (*Zakon o strateškim investicijskim projektima Republike Hrvatske*),[37] which came into force on 5 April 2018, provides for the establishment of the one-stop-shop for projects of strategic importance ("PSIs") to the Croatian State ("State"). Private, public, or public–private investment projects in the areas of energy, transport, infrastructure, or environmental protection, among others, may be designated as PSIs. The law sets out detailed criteria that projects must meet, and the procedure for assessment and selection of such projects. Projects with a PSI status should benefit from faster and more efficient permit-granting procedures and improved regulatory treatment.

The law has introduced competent bodies for assessing and implementing PSIs, such as: (i) the Assessment Commission (*Povjerenstvo za procjenu i utvrđivanje prijedloga strateških projekata*) composed of high-level government officials; and (ii) the Operational Group (*Operativna skupina za pripremu i provedbu strateških projekata*) composed of officials from different state administration bodies at the central, regional, and local level. On an administrative level, MGOR is designated as the competent authority responsible for receiving project notifications and providing administrative work for the Assessment Commission.

In line with the new Act on Renewable Energy Sources and High Efficiency Cogeneration, with effect from 23 December 2021 (see section F.1), MGOR has be designated as a contact point for the entire administrative permitting process for RES and cogeneration projects development.

A new entrant must fulfil certain conditions to become a market participant in the Croatian electricity market. Firstly, a new entrant must apply for a licence for their respective electricity activity and provide evidence that they meet the required conditions.

A legal entity must be established in Croatia to obtain the requisite licence. The applicant company usually operates in the form of a limited liability company or a joint stock company. However, the ZTEE provides for a simplified licensing procedure for active electricity traders or suppliers based in EU Member States. In accordance with the new Ordinance on Licences for the Performance of Energy Activities and Keeping of the Registry on the Issued and Revoked Licences (*Pravilnik o dozvolama za* *obavljanje energetskih djelatnosti i vođenju registra izdanih i oduzetih dozvola za obavljanje energetskih djelatnosti*)[38], with effect from 16 April 2022, active electricity traders and/or supplier from EU Member States are not required to set up a separate legal entity in Croatia.

Additionally, to participate on the electricity market, a new entrant must enter contractual relations with the relevant market players depending on the designated energy activity to be performed (eg, generation, supply and/or trade). To gain access to the network system, they must conclude a connection agreement with HOPS or HEP-ODS and fulfil all required conditions (see section A.2). A network use contract must also be concluded with HOPS or HEP-ODS (see section C.1).

To trade in electricity, having obtained the Energy Identification Code ("EIC") and registration with the Centralised European Registry of Energy Market Participants ("CEREMP") in accordance with REMIT requirements, a party must enter into an electricity market participation agreement with HROTE.

As of 1 September 2016, a balance responsibility contract must be concluded between a market balancing group manager and HOPS. The balance responsibility contract regulates the responsibility of the balancing group manager for imbalances of all members of the balancing group. The mutual relationships within the balancing group must be regulated on the basis of a contract entered into between the balancing group manager and market participants that are balance group members.

In terms of electricity import or export, an application to HOPS for participation in cross-border transmission capacities allocation, and for participation in allocation of cross border transmission capacities, is required (see section A.7).

To become CROPEX members and trade on the day-ahead trading platform, a market participant needs to enter into a membership agreement with CROPEX. The prerequisite for the membership is obtaining an energy licence from HERA, entering into a balance responsibility contract with HOPS, and the conclusion of an electricity market participation agreement with HROTE. However, as of 22 October 2021, electricity suppliers or traders from another EU Member State are not required to obtain a trading licence from HERA for the wholesale trading of electricity effected solely via the electricity power exchange. However, they must comply with the general rules on business operation of foreign companies in the Republic of Croatia.

Licensing regime

The licensing regime determines various licences, permits, and/or other approvals that are required for the planning, construction, and operation of generation facilities, and the transmission and distribution networks, in line with applicable laws and regulations governing physical planning and building, energy sector, environmental and nature protection as well as technical and security regulations.

One of the key amendments introduced by the new ZTEE concerns the introduction of an obligatory public tender for the issuance of the energy approval permit for the construction of new generating installation or energy storage facility (*energetsko odobrenje za proizvodno postrojenje ili postrojenje za skladištenje energije*). The public tender will be carried out by MGOR ex officio or at the written request of an interested project developer. The project developer who has acquired the relevant proprietary rights over the land plots comprising the project will be exempted from the mandatory public tender. Project developers that intend to construct new generating installations or energy storage facilities must comply with the tender participation requirements set out in the law and implementing regulation, which remains to be adopted in the upcoming period. The energy approval permit will be valid for five years or seven years in case of hydro power plants with installed capacity above 10MW. The project developer will be required to build the generating installation and obtain the use permit within seven years or ten years (in case of hydro power plants with installed capacity above 10MW) as of the date the energy permit has become final. However, since up to now the implementing regulation required to set out conditions for public tender for the issuance of the energy approval permit was not adopted by the Government, no public tenders pursuant to the ZTEE are carried out in Croatia so far.

The project developer will be required to pay a fee for the issuance of the energy approval permit to HROTE. Upon request by the project holder, the amount of this paid fee can be accepted as a bid bond for participation in the FIP auction for the award of market premium (see section F.2).

As regards the existing projects under development, the new ZTEE provides for a permitting regime under which project developers that have obtained the location permit, and/or the grid connection agreement, and/or grid connection approval, and/or EIA decision for the project until the entry into force of new law, were required within 90 days ie until 19 January 2022, to submit to MGOR a request with expression of interest for public tender for the issuance of energy approval permit. Along with the request, developers had to submit supporting documents and pay a fee to HROTE of HRK50.00 per kW (ie €6.64/kW) of the connection capacity of the production plant (after obtaining the energy approval permit).

With respect to these projects, MGOR will carry out the public tender according to criterion on the date of obtained permits/agreements ie in terms of their legal effect. For the project sites for which there will be more interested project developers/bidders, a project developer who has 'first' obtained the respective permits will be selected as preferred bidder. The energy approval permit will be valid for five years as of the date it has become final and enforceable, and within this period the project holders will be required to complete construction of the plant and obtain the use permit.

In addition, HOPS was required by law to request from RES project developers that they supplement until 19 January 2022 their request for issuance of the final grid connection study with an energy approval permit. As this was not possible, the connection approval process of these projects seems to be suspended until the relations between these investors and HOPS is regulated.

Under the ZTEE, generators of electricity from RES and/or cogeneration plants that fall under the category of 'simple buildings', pursuant to the applicable building regulations, can obtain the status of an eligible generator under a simplified administrative procedure.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

In Croatia, electricity transmission and distribution, and the organisation of the electricity market and electricity supply under a universal service, are regulated activities that are performed as a public service. HEP ELEKTRA d.o.o. provides the public service of universal electricity (for household customers) and supplier of last resort (for business customers who are left without a supplier) in Croatia.

Customers under universal service are supplied with electricity under regulated conditions. Household customers may either select or automatically use the supply under universal service as a public service, according to the regulated conditions. A supplier of last resort will supply electricity as a public service under regulated conditions to a final (non-household) customer who is left without a supplier in certain circumstances. Pursuant to the ZTEE, customers can enjoy both universal service and a last resort electricity supply for an indefinite period of time.

Smart metering

The requirement for smart metering introduced by the recast Electricity Directive has been transposed into Croatian legislation by the new ZTEE. Under the ZTEE, the grid operator must specify the technical requirements and time frame for introducing smart metering systems. Following an economic assessment of the long-term costs and benefits to the market, and the individual consumer, by HERA, the ministry responsible for the energy sector has the power to adopt the decision and programme with a target of up to ten years for the deployment of smart metering systems. Where the deployment of smart metering systems is assessed positively, at least 80% of final customers must be equipped with smart meters within seven years of the date of the decision. Their practical implementation will be supervised by HERA.

Besides, HEP-ODS installs smart meters at the request of final customers, as well as when replacing certain meters and within pilot projects of smart grids.[39]

Under the RRP, the objective is to install at least 40000 smart meters and to connect new consumers to the smart grid by 2024.

Electric vehicles

According to the Croatian Act on the Deployment of Alternative Fuels Infrastructure[40] and the Decision on the Adoption of the National Policy Framework for the Deployment of Infrastructure and the Development of Alternative Fuels Market in Transport,[41] Croatia has set a national target to build up the publicly accessible infrastructure for the supply of electricity to motor vehicles, and that by 2020, recharging points will be available every 50 kilometres of the highway and in every urban agglomeration (ie cities/towns with more than 20,000 inhabitants). There are currently around 330 installed charging stations in Croatia. The network of electric vehicle ("EV") charging stations is being developed by HEP and Croatian Telecom, ie HT. In 2020, there were around 1,343 registered EVs and around 553 plug-in hybrid vehicles.[42] In 2022, the Croatian Environmental Protection and Energy Efficiency Fund (*Fond za zaštitu okoliša i energetsku učinkovitost*) ("FZOEU") had an incentive scheme in place which co-financed the purchase of electric and plug-in hybrid vehicles.

A.7 Cross-border interconnectors

Croatia has cross border interconnections with all of its neighbours (Slovenia, Serbia, Bosnia and Herzegovina, and Hungary) save for Montenegro and Italy. The Rules on Use of Cross-Border Transmission Capacities of HOPS (*Pravila o korištenju prekograničnih prijenosnih kapaciteta*) regulate the use of cross-border capacities allocated on yearly, monthly, daily, and intraday auctions at the interconnection lines of the Croatian electricity system with the electricity systems of neighbouring countries. Cross-border transport capacities are made accessible to market participants through market-based procedures.

The South East Europe Coordinated Auction Office, ie SEE CAO, conducts the annual, monthly, and daily coordinated auctions at the border with Bosnia and Herzegovina. HOPS carries out coordinated intraday allocation for both directions at the border with Bosnia and Herzegovina.

The Joint Allocation Office ("JAO") carries out the annual, monthly, and daily coordinated auctions for the allocation of cross-border capacities in both directions at the borders with Serbia. The Serbian TSO, ie EMS, carries out the intraday allocation on the Croatian-Serbian border.

The Slovenian TSO, ie ELES, carries out coordinated intraday allocation for both directions at the border with Slovenia. The JAO carries out the annual, monthly, and daily coordinated auctions for the allocation of cross-border capacities in both directions at the borders with Slovenia and Hungary. HOPS has carried out coordinated intraday allocation for both directions at the border with Hungary since March 2018. Implicit auctions are conducted at the border with Slovenia following the Croatia DAM coupling with Slovenia in June 2018. From November 2019, Croatian borders with Slovenia and Hungary are included in the intraday market coupling of EU countries through the XBID project.[43]

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

INA carries out oil and natural gas development activities in Croatia. Crude oil is produced at 38 oil fields, and gas condensate is made at 10 gas condensation fields. In 2021, about 69% of the imported crude oil, 28% of other imported and domestic raw material, 2% of the domestic crude oil and 1% of the domestic condensates were used as raw material for the production of oil products.44

See also section E.

Gas

Nature of the market

Although the Croatian gas market has legally been liberalised since 1 August 2008, the first signs of a de facto opening of the market occurred in the gas season 2012/2013 following the removal of a price cap for gas supply to eligible customers (but only in relation to non-household customers), and new wholesale suppliers entering the market.

From 1 April 2014 until 31 March 2021, the State-owned electricity company HEP was appointed the wholesale gas supplier to other Croatian suppliers with public service obligations for the needs of household customers. During this period, the price at which HEP then sold gas to other public service obligation suppliers has remained regulated. In addition, HEP has been awarded 60% priority for booking storage capacity with the UGS Okoli. As of 31 March 2021, the role of the wholesale gas market supplier was abolished.

In 2021, the market share held by the major gas suppliers on the wholesale market were: HEP (ie, both HEP-Trgovina and HEP) with a market share of 32%, PPD with a market share of 25%, INA with a market share of 18%, and other gas suppliers (less than 7%) with a market share of 25%.[45]

Gas transportation, distribution, and storage are regulated energy activities performed as a public service. In line with ZTP, the activities related to gas transportation and gas storage were legally unbundled. The state owned PLINACRO, which was separated from INA in 2002, is the TSO. In 2007, PLINACRO was designated as the TSO for a period of 30 years. The gas storage operator is PSP, which was legally unbundled from INA and bought by the state owned PLINACRO. Of the DSOs, 11 are legally unbundled from retail and 19 are exempt from unbundling as they have fewer than 100,000 customers.

Key market players

Due to the continuous decrease in domestic production, Croatia's dependence on gas importation is growing significantly. About 25.7% of the natural gas supplied in 2021 originated from domestic production at 17 onshore fields in the Pannonian basin and 11 offshore fields in the three exploitation areas in the North Adriatic.[11] The remaining demand was met by the importation of natural gas through interconnection points and from the liquefied natural gas ("LNG") terminal as a new gas supply route. In 2021, the entry of gas into the transmission system reached 31,712kWh, out of which 5,775kWh (18.2%) originated from domestic production, 6,225kWh (19.6%) from imports, 15,703kWh from the LNG terminal (49.5%), and 4,009Wh (12.6%) from the underground gas storage facility PSP Okoli (UGS Okoli).[47]

In the Croatian gas industry, the key market player is INA-INDUSTRIJA NAFTE d.d. ("INA"), a vertically integrated company that is 49.08% owned by MOL Hungarian Oil and Gas Plc., 44.84% owned by the Republic of Croatia and 6.08% owned by institutional and private investors.[48] INA is currently the only producer of natural gas in Croatia.

Other market players in the gas industry are:

- HEP Group companies, with a market share of 32%;
- PRVO PLINARSKO DRUŠTVO d.o.o. ("PPD"), with a market share of 25%;
- INA, the major gas suppliers, with a market share of 18%;
- GEOPLIN, with a market share of 6.2%;
- PLINACRO d.o.o., the TSO, a wholly state-owned company ("PLINACRO"); and
- PODZEMNO SKLADIŠTE PLINA d.o.o. (owned by PLINACRO) ("PSP"), the gas storage operator.

The only underground natural gas storage facility in Croatia is PSP Okoli, ie UGS Okoli, located near the city of Sisak with an operating storage volume of 553 million cubic metres. According to HERA's licence registry, a total of 30 companies are licensed as gas distributors. A total of 39 companies have obtained supply licences. There are currently 37 companies licensed as gas traders in Croatia.

Regulatory authorities

MGOR is responsible for the oil and gas industry. The national regulatory authority is HERA, whose scope of work is similar (see section A.1). HROTE is the operator of the gas market.

Legal framework

In addition to the ZE and ZREA, the main legal act is the Gas Market Act (*Zakon o tržištu plina*)[49] ("ZTP") with effect from 3 March 2018, and various secondary legislation that regulates specific areas of the gas industry, including the organisation of the market, technical conditions, and methodologies on tariff systems.

Implementation of EU gas directives

The Third Gas Directive has been transposed into national law by provisions of the ZE, ZREA and ZTP. As discussed above, the unbundling of activities related to gas transportation and storage has already happened. The certification process of PLINACRO as the ownership unbundled TSO was finalised on 23 July 2021, with the adoption of a HERA Decision on the certification granted to PLINACRO d.o.o., as the TSO with unbundled ownership.[50] In December 2020, HERA approved the Ten-Year Network Development Plan of the Gas Transmission System of PLINACRO ("TYNDP 2021–2030").[51]

B.2 Third party access regime to gas transportation networks

Non-discriminatory access to the transportation or distribution network according to the principle of regulated third party access ("TPA") is provided for in line with the ZTP and the Network Code for the transmission system, and the Network Code for the distribution system. The new Network Code for the transmission system of PLINACRO (*Mrežna pravila transportnog sustava*)[52] came into force on 9 June 2018.

As a rule, the final customer requesting to be connected to the gas system must primarily request access to the distribution system from the DSO in its area. The ZTP provides for certain exceptional cases when the final customer may directly be connected to the transportation system.

Access to the network can be denied in the following cases: (i) lack of capacity; (ii) where access to the system would prevent the system operator from performing the public service obligation; and (iii) where access to the system would cause serious financial and economic difficulties to gas undertakings with regards to take-or-pay contracts concluded prior to a request for approval of access, which is subject to prior approval from HERA. A system operator that has refused access to the system on the basis of a lack of capacity or for other justified reasons as set out in the ZTP, must make the necessary changes and expansion of the system in order to enable access within a reasonable period of time, as far as it is economically feasible to do so, or when a potential customer is willing to pay.

A gas undertaking that intends to contract gas supply but has been refused access to the distribution or transportation system by a final decision, may construct a direct gas line, subject to prior approval from HERA. The refusal of access must be notified in writing. The party seeking access to the system can file an appeal with HERA if access to the system is refused. HERA must make a decision as to whether the prerequisites for the refusal of access apply within 60 days. No appeal is permitted against the decision of the HERA, but the injured party may bring a claim before the competent administrative court. Major new gas infrastructure (ie, interconnectors, gas storage systems, and LNG facilities) may, upon request, be exempt from the application of TPA rights under certain conditions set out in the ZTP.

In August 2017, HERA adopted the criteria for issuance of the approval for construction and operation of a direct gas pipeline, which entered into force on 10 August 2017 (*Kriteriji za izdavanje suglasnosti za izgradnju i pogon izravnog plinovoda*).[53]

B.3 LNG terminals and storage facilities

The storage of natural gas is carried out by PSP as the gas system operator (see section B.1) pursuant to the ZTP and the Storage Code (*Pravila korištenja sustava skladišta plina*),[54] which came into force on 9 June 2018. Gas storage is a regulated energy activity performed as a public service. In May 2018, HERA adopted the Methodology for Determining Tariffs for Gas Storage (*Metodologija utvrđivanja iznosa tarifnih stavki za skladištenje plina*),[55] which entered into force on 15 June 2018. On the basis of the methodology, in September 2022 HERA adopted the Decision on gas storage tariff rates for the third regulation period 2022 to 2026 (*Odluka o iznosu tarifnih stavki za skladištenje plina*)[56] for PSP as the gas system operator, which entered into force on 1 October 2022. On the basis of the methodology (see section B.3), in September 2022 HERA adopted the Decision on price list for non-standard services of the gas system operator for the third regulation period 2022 to 2026 (*Odluka o cjeniku nestandardnih usluga operatora sustava skladišta plina*)[57], which entered into force on 1 October 2022.

Exceptionally, the ZTP provides that gas storage may be performed as a market activity, provided that the gas storage operator obtains prior approval from HERA. Under the ZTP, the criteria for issuing the approval of HERA is determined by taking into account the level of competition in relation to energy activity of gas storage in Croatia and the region, as well as the issues of security of gas supply in Croatia. Prior to issuing the respective approval, HERA must obtain the opinion of the ministry competent for the energy sector and the Croatian Competition Agency, ie ATZN (*Agencija za zaštitu tržišnog natjecanja*). To date, no such criteria for determining access to the gas storage system have been issued.

On 1 January 2021, the first LNG terminal in Croatia became operational. The construction of the floating LNG terminal on the island of Krk in the North Adriatic with a capacity of 2.6 billion cubic metres per year, which now provides new supply route to Croatia, along with the increase of the level of diversification of gas supply sources, has increased competitiveness on the market and the security of supply. The LNG re-gasification facility was given 'project of common interest' status in February 2017 and the project development company LNG Hrvatska d.o.o. (LNG Croatia) (with HEP and PLINACRO each holding 50% of the equity shares thereof) was licensed as the LNG facility operator for a period of three years in accordance with the New TEN-E Regulation.[58] In February 2020, LNG Croatia was re-licensed as the LNG facility operator for an additional three-year period.

To create a legal framework for the development of the LNG terminal, a new Act on LNG Terminal (*Zakon o terminalu za ukapljeni prirodni plin*)[59] was adopted in June 2018, and entered into force on 5 July 2018.

Pursuant to the ZTP, a LNG facility operation is a regulated energy activity that is carried out as a public service in the gas sector. In July 2021, LNG Croatia adopted the new Rules for Use of LNG Terminal (*Pravila korištenja terminala za UPP*)[60] which entered into force on 5 August 2021. This set out specific provisions in relation to the development, manner of management, and usage of the LNG terminal. This includes contractual relations and general terms and conditions for using the LNG terminal. In May 2018, HERA adopted the Methodology for Determining Tariffs for LNG Reception and Dispatch (*Metodologija utvrđivanja iznosa tarifnih stavki za prihvat i otpremu ukapljenog prirodnog plina*),[61] which entered into force on 15 June 2018. The regulation model is based on the regulation incentive method (ie the revenue cap method). On the basis of the methodology, in September 2022 HERA adopted the Decision on tariff rates for the LNG reception and dispatch for the first regulation period 2022 to 2025 (*Odluka o iznosu tarifnih stavki za prihvat i otpremu ukapljenog prirodnog plina*)[62] for LNG Croatia, which entered into force on 1 October 2022. On the basis of the Methodology for Determining Prices of Non-Standard Services of Gas Transportation, Distribution, Storage, LNG Reception and Dispatch and Public Service of Gas Supply (*Metodologija utvrđivanja cijene nestandardnih usluga za transport plina, distribuciju plina, skladištenje plina, prihvat i otpremu ukapljenog prirodnog plina i javnu uslugu opskrbe plinom*),[63] in September 2022 HERA adopted the Decision on price list for non-standard services of the LNG terminal operator (*Odluka o cjeniku nestandardnih usluga operatora terminala za ukapljeni prirodni plin*)[64] for the first regulation period 2022 to 2025, which entered into force on 1 October 2022.

A non-discriminatory TPA regime also applies to LNG terminals and gas storage facilities (see section B.2). However, third party access rights can be denied in relation to major new gas infrastructure such as interconnectors, gas storage systems, and LNG facilities, following approval from HERA, and the fulfilment of certain prescribed conditions.

B.4 Tariff regulation

A tariff charging regime applies to the transportation system, both at the transportation and distribution level. The gas transportation tariff regime is based on HERA's Methodology for determining tariff rates for gas transportation (*Metodologija utvrđivanja iznosa tarifnih stavki za transport plina*),[65] which regulates the mode, method, and conditions of the accounting of the network tariffs. Following amendments to the legal framework, Croatia has adopted the entry-exit transportation tariff system. The regulation model is based on the regulation incentive method (ie the revenue cap method); the regulation period is five years. The actual tariff rate is set by the TSO, with the prior approval of HERA. In the event that HERA refuses to give approval, HERA will independently set the tariff rates. On the basis of the methodology, in September 2022 HERA adopted the Decision on gas transportation tariff rates for the third regulation period 2022 to 2025, (*Odluka o iznosu tarifnih stavki za transport plina*)[66] for PLINACRO as the TSO, which entered into force on 1 October 2022. On the basis of the methodology (see section B.3), in September 2022, HERA adopted the Decision on price list for non-standard services of the TSO for the third regulation period 2022 to 2025 (*Odluka o cjeniku nestandardnih usluga operatora transportnog sustava*)[67], which entered into force on 1 October 2022.

Apart from the licence issued by HERA, a concession for gas distribution, or for building a distribution system, is also required to operate a distribution network. The gas distribution tariff regime is based on HERA's Methodology for determining tariff rates for gas distribution (*Metodologija utvrđivanja iznosa tarifnih stavki za distribuciju plina*),[68] which sets out the mode, method, and conditions of the accounting of the network tariffs. The regulation model is based on the regulation incentive method (ie the revenue cap method). The tariff system in the distribution system is based on the post stamp principle. The actual tariff rate is set by the DSO, with the prior approval of HERA. In the event that HERA refuses to give approval, HERA will independently set the tariff rates. On the basis of the methodology, in September 2022 HERA adopted the Decision on gas distribution tariff rates for the third regulation period 2022 to 2026 (*Odluka o iznosu tarifnih stavki za distribuciju plina*)[69] for the 31 DSOs, which entered into force on 1 October 2022. In addition, in September 2022 HERA adopted the Decision on price list for non-standard services of the DSO for the third regulation period 2022 to 2026 (*Odluka o cjeniku nestandardnih usluga operatora distribucijskog sustava*)[70], which entered into force on 1 October 2022.

The final price of gas charged to household customers is set by HERA in accordance with the Methodology for determining tariff rates for public service gas supply and last resort supply (*Metodologija utvrđivanja iznosa tarifnih stavki za javnu uslugu opskrbe plinom i zajamčenu opskrbu*).[71] Tariff rates for gas supply for the period from 1 January to 31 March 2023 are set by HERA.[72] The final gas price is composed of the gas purchase costs, the gas distribution costs, and the supply margin.

B.5 Market entry

A new entrant to the market must obtain several licences depending on the designated energy activity to be performed and enter into certain agreements with other market participants. Establishing a legal entity in Croatia is a condition for obtaining the respective licences and the applicant company usually operates in the form of a limited liability company or a joint stock company.

The licensing regime for electricity is also applicable to the gas industry (see section A.5). A licence for the performance of energy activities (*dozvola za obavljanje energetske djelatnosti*) is needed to carry out energy activities such as: (i) gas generation; (ii) natural gas generation; (iii) gas transportation; (iv) gas storage; (v) LNG facility operation; (vi) gas distribution; (vii) organising the gas market; (viii) gas trading; and (ix) gas supply.

However, the ZTP provides for a simplified licensing procedure for gas traders or suppliers based in EU Member States interested in entering the Croatian energy market. Gas traders from EU Member States are no longer required to set up a separate legal entity in Croatia.

The contractual relations between the gas supplier and final customer are regulated in accordance with the General Conditions of Natural Gas Supply (*Opći uvjeti opskrbe plinom*).[73]

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Under the ZTP, the following are to be performed as a public service: gas transmission, gas distribution, gas market organisation, wholesale market supply, gas supply activities as a universal service, gas storage, and LNG facility operations. The ZTP also foresees public service obligations ("PSOs") in the context of the provision of a universal service.

The ZTP also provides that existing suppliers of household customers are designated to act as a supplier with PSOs (that is, to supply gas to households under regulated conditions and at regulated prices) until 31 March 2021. Thereafter, suppliers with PSOs for the needs of household customers are appointed for a three-year term on the basis of a public tender. For the period from 1 April 2021 until 30 September 2024, only 14 gas suppliers (instead of 32) are appointed as suppliers with PSOs.[74]

The ZTP provides that a supplier of last resort (that is, to supply gas under regulated conditions to a final customer who is left without a supplier under certain conditions) will be designated for a period of three gas years. In light of the EU wholesale natural gas prices increases, and in accordance with the amended methodology with effect from 17 February 2022 (see section B.4), in February 2022 HERA has conducted the public tender, and thereafter, in March 2022 HERA has appointed HEP-PLIN d.o.o. as the new supplier of last resort for the period from 10 March 2022 until 30 September 2024.[75]

Smart metering

Under the ZE, the DSO must specify the technical requirements and costs of introducing smart metering and intelligent metering systems. Following a cost-benefit analysis by HERA, and a hearing of the consumer protection body, the ministry responsible for the energy sector has the power to adopt the plan and programme of measures for the introduction of smart metering systems to final customers. Their practical implementation will be supervised by HERA. Unlike the electricity market, there is no deadline set out under law for the rollout of smart meters in the gas sector. In 2020, HERA undertook its first activities to prepare a background study for determining the technical requirements and costs of introducing advanced metering devices and their integration into a network for final customers of natural gas. Reportedly, in 2021, eight DSOs have ongoing pilot projects for the introduction of smart metering and intelligent metering systems.[76]

B.7 Cross-border interconnectors

There are currently two cross-border interconnections in Croatia, which are the interconnection Dravaszerdahely–Donji Miholjac, between Hungary and Croatia, and the interconnection UMS Rogatec, between Slovenia and Croatia. Gas can also be exported from Croatia to Slovenia and the firm capacity is available from January 2019. As regards the gas export from Croatia to Hungary, the firm capacity is available from January 2020 when the compression station in Velika Ludina was put in operation.[77]

C. Energy trading

C.1 Electricity trading

In Croatia, wholesale electricity can be traded on the OTC market based on bilateral agreements and on power exchange CROPEX (see section A.3). To pursue an electricity trading activity in Croatia, a trading licence issued by HERA is required (with an exemption for electricity suppliers or traders from another EU Member State for the wholesale trading solely on power exchange). Generators, suppliers, and traders must conclude an agreement with HROTE as the operator of the electricity market.

EFET General Agreements are used in relation to wholesale power trading in Croatia. However, market players are also using their own templates. Accordingly, there is no set of standardised agreements commonly used in Croatia.

The CROPEX DAM came into operation in February 2016, but with no market coupling applied. The launch of the CROPEX IDM in April 2017 marks a major step toward further liberalisation of the Croatian electricity market. The CROPEX IDM meets the legal prerequisites in accordance with the EU CACM Regulation for the implementation of cross-border market coupling of the CROPEX IDM with the neighbouring EU IDMs. For information on the country's participation in EU market coupling, see sections A.3 and A.7.

A functional ancillary service and balancing energy market is not yet developed in Croatia. HOPS, in its capacity as the TSO, purchases and sells electricity from market participants to balance the electricity system, while HROTE, as the operator of the electricity market, performs a quantitative calculation of balancing energy.

Under the Rules on Electricity Market Organisation with effect from 15 November 2019, the new balancing group model has been introduced on the electricity market (see section A.3). Accordingly, the new Rules on the Electricity System Balancing of HOPS (*Pravila o uravnoteženju elektroenergetskog sustava*) came into effect on 7 December 2019.[78]

The conditions for the full opening of the balancing energy and ancillary service markets are not currently being met. In 2021, HEP-Proizvodnja d.o.o. remained the only provider of balancing energy from the automatic frequency restoration reserves ("aFRR") and from the manual frequency restoration reserves ("mFRR") and was the dominant provider of the ancillary services on the market (73.9%).[79] In December 2020, mFRR services for system security were for the first time provided by third-party service providers outside HEP under a pilot project. Prices for the provision of these services are currently regulated pursuant to the Rules on the Electricity System Balancing of HOPS and the Methodology for determining the prices for the provision of ancillary services of HOPS (*Metodologija za određivanje cijena za pružanje pomoćnih usluga*) from 22 September 2020.[80] From 1 January 2020, the same imbalance price applies to all balance groups for every hour. Pursuant to the Commission Regulation (EU) 2017/2195, establishing a guideline on electricity balancing ("EBGL"), HOPS will in future have to use the three EU energy balancing platforms: the Imbalance Netting (IN)-Platform, the aFRR-Platform, and the mFRR-Platform. However, based on the HERA decision, HOPS has been granted exemption to join the aFRR platform and mFRR platform until 24 July 2024. The balancing system would benefit if the obligation imposed by law on electricity suppliers to take a share in net electricity delivered by eligible generators at a regulated price from HROTE as the electricity market operator would be abolished, as the day-ahead production plan would be more consistent with the expected delivery of electricity to the grid.[81]

The ECO-BG began its operations as of 1 January 2019 and is managed by HROTE as the electricity market operator. It was set up to balance RES and cogeneration plants operated by eligible producers. All eligible generators that have been granted the right to an incentive price on the basis of the old Feed-In-Tariffs ("FiTs") or a guaranteed purchase price (ie small RES installations of up to 500kW) must become members of the ECO-BG. The obligations on ECO-BG members are regulated by the Rules for ECO balance group management of HROTE from 31 December 2018 (*Pravila vođenja EKO bilančne grupe*).[82] In line with the new RES Act, with effect from 23 December 2021, eligible generators that will be granted a market premium under the Feed-In-Premium ("FIP") support scheme can also become members of the ECO-BG.

From 1 January 2022, HROTE must sell 40% of electricity from the ECO balance group on the electricity market (including on the CROPEX spot market). In 2023, the electricity suppliers must take 60% of electricity fed into grid, which HROTE purchased from eligible producers.[83] The sale of electricity must be carried out in a transparent and non-discriminatory manner in accordance with the Rules for the sale of the ECO balance group electricity of HROTE from 31 December 2018 (*Pravila prodaje električne energije*).[84]

C.2 Gas trading

There is currently no commodity exchange, or gas hub, in Croatia. To pursue gas trading activity in Croatia, companies require a licence for trading issued by HERA. If the intended activities of wholesale gas trading also include the sale of gas to end customers, a licence for supply issued by HERA is also required.

Croatia has introduced the entry-exit model and a virtual trading point ("VTP") as of 1 January 2014. Rules on the VTP are set out under the Rules on the Gas Market Organisation of HROTE (*Pravila o organizaciji tržišta plina*),[85] which came into force on 9 June 2018, and the Network Code for the transmission system. VTP is defined as a point of gas trading following its entry into the transmission network and prior to its exit from the transmission network, including the gas storage system. It is not necessary to book entry-exit capacity or storage system capacity to trade on the VTP. However, only a balancing responsible party (*voditelj bilančne skupine*) ("BRP") who is a transmission system user is entitled to trade on the VTP. This means that only market participants in possession of a supply or trade licence, and who have signed a transport contract with the TSO, can gain access to the VTP. HROTE publishes, on its website, the form that allows the placing of a bid for the purchase or sale of gas on the VTP.[86] Trading at the VTP is done independently between the BRPs; neither the TSO nor HROTE act as a clearing house, therefore each party bears the counterparty risks of the other. The parties can use either bespoke agreements or the standard agreements published on HROTE's website.

Each gas market participant, except for HROTE as the gas market operator, must be a member of the balancing group. A balancing group is a virtual association of one or more gas market participants, which is organised on a commercial basis primarily for the purpose of optimising the costs of balancing, and which is organised and managed by the BRP. The balancing group is comprised of the direct members (ie the gas supplier and gas trader) and indirect members (ie the final customer). HROTE keeps the register of the BRPs on the gas market and publishes it on its website.[87]

PLINACRO, as the TSO, is responsible for the allocation and contracting of transmission system capacity, in compliance with received requests for transmission system capacity booking and available transmission system capacity.

In addition to the trading on the VTP, a trading platform has come into operation that enables trading the BRPs and PLINACRO for the purpose of balancing the gas transmission network in accordance with the NC GBTN. Short-term standardised products (ie title and locational products) can be traded on the trading platform for delivery on a same-day or day-ahead basis. The trading platform enables transparent, non-discriminatory access and anonymous trading. The platform is operated by HROTE.

As regards the implementation of the NC CAM, PLINACRO has chosen to use different platforms for different interconnection points ("iPs"). PRISMA is used to auction capacity at the iPs between Croatian and Slovenia, ie UMS Rogatec, and the Regional Booking Platform is used to auction capacity between Croatia and Hungary, ie UMS Dravaszerdahely.

D. Nuclear energy

Nuclear energy in Croatia is only generated in the Nuclear Power Plant in Krško in Slovenia, which is 50% owned by Slovenia, ie Gen Energija d.o.o., and 50% owned by Croatia, ie HEP. Croatia is entitled to 338MW of the power generated in the Nuclear Power Plant in Krško.

Activities in the nuclear energy sector are regulated by the Act on Radiation and Nuclear Safety (*Zakon o radiološkoj i nuklearnoj sigurnosti*),[88] as well as by secondary legislation. The state administrative body in charge of the nuclear sector in Croatia is the Ministry of Interior (*Ministarstvo unutarnjih poslova*).

E. Upstream

The exploration and production of oil and natural gas in Croatia is primarily regulated by the Hydrocarbons Exploration and Production Act (*Zakon o istraživanju i eksploataciji ugljikovodika*)[89] ("ZIEU"), which came into force on 14 June 2018. Additionally, various by-laws govern specific areas of the hydrocarbons sector. The ZIEU provides a legal framework for the exploration and production of the hydrocarbons (oil, natural gas, and gas condensates), geothermal energy, storage of natural gas, and geological storage of carbon dioxide ("CO_2"). The ZIEU also contains special provisions concerning the licensing and concession regimes applicable to the exploration and production of hydrocarbons. The ZIEU is aligned with the requirements of the Hydrocarbons Licensing Directive.

The Croatian Hydrocarbon Agency (*Agencija za ugljikovodike*) ("AZU") was established in February 2014.[90] The AZU provides operational support to competent administration authorities in activities of exploration and production of hydrocarbons, geothermal waters for energy purposes, and permanent geological storage, and it is responsible for, among others, the launching of a public tender process for the award of a licence for exploration and concession for production, the supervision of the licensed activities, as well as cooperation with investors.

Following the transposition of the Offshore Safety Directive into national law, the new Act on the Safety of Offshore Exploration and Production of Hydrocarbons (*Zakon o sigurnosti pri odobalnom istraživanju i eksploataciji ugljikovodika)*[91] ("ZSOIEU") entered into force on 25 July 2015 and became fully applicable as of 19 July 2018. The new offshore legal regime establishes a minimum set of rules for preventing major accidents in offshore oil and gas operations and limiting the consequences of such accidents.

The ZSOIEU provides for the establishment of a special competent authority, the Coordination for the Safety of Offshore Exploration and Production of Hydrocarbons (*Koordinacija za sigurnost pri odobalnom istraživanju i eksploataciji ugljikovodika*) ("the Coordination body"). The Coordination body was established in September 2017[92], and is comprised of the representatives of the different state authorities, such as, among others, MGOR, AZU, the Croatian Register of Shipping (*Hrvatski registar brodova*) ("CRS"), the Ministry of Maritime Affairs, Transport, and Infrastructure (*Ministarstvo mora, prometa i infrastrukture*) ("MMPI"), and the Ministry of Interior - Civil Protection Directorate (*Ministarstvo unutarnjih poslova – Ravnateljstvo civilne zaštite*) ("MUP").

Further implementing regulations and guidelines were made available on the website of the Coordination body/AZU during 2017 and 2018 respectively. Operators of existing offshore gas installations and operations in Croatia were required to bring their operations in compliance with new regulatory requirements.

F. Renewable energy

F.1 Renewable energy

Croatia has reached its national RES target for 2020 as set out in the RED, namely, to have at least a 20% share from RES in gross final energy consumption by 2020. Under the Energy Sector Development Strategy until 2030, the national RES target for 2030 is set at an ambitious share of 36.6% of energy from RES in gross final energy consumption by 2030. The key implementing document until 2030 is the Integrated National Energy and Climate Plan for the period from 2021 until 2030 (*Integrirani nacionalni energetski i klimatski plan za Republiku Hrvatsku za razdoblje od 2021. do 2030. godine*) ("NECP")[93], which defines implementing measures for the set national targets.

Most of the increase in the renewable energy production is expected in the electricity sector. Also, one of the main goals of the new Energy Development Strategy is to increase the renewable power generation capacities.

Currently, Croatia has more than 5GW of installed capacity for electricity generation (both conventional + RES). A total of 26 wind power plants with 980MW and solar (PV) plants with 138MW are connected to both the distribution and transmission grid in Croatia.[94] According to Croatia's Resilience and Recovery Plan for the period 2021-2026 (*Nacionalni plan oporavka i otpornosti*) ("RRP"), which was in adopted in July 2021, Croatia aims to have at least 1.5GW of new renewable power capacity until 2025 and more than 2.5GW until 2030.

At the end of 2021, the total operational capacities of RES plants that receive incentive price under the RES support schemes in Croatia reached around 1048MW, out of which wind power plants with 717.8MW, solar power plants with 55.9MW, biomass power plants with 96MW, biogas power plants with 46.9MW, cogeneration facilities with 113.2MW, (small) hydropower plants with 6.3MW, geothermal power plants with 10MW and sewage gas power plants with 2.5MW.[95]

According to the TYNDP 2022 to 2031 of HOPS, major upgrades and expansion of the transmission grid are needed and planned in the upcoming period 2022-2031. Due to planned large-scale integration of wind and solar (PV) energy, the significant increase in investments in the grid upgrades and construction of grid connections is required and planned, amounting up to HRK9.3 billion (around €1.2 billion). According to the HOPS's short-term and long-term plans, a total of around 679MW of new power plants is planned to be connected to the transmission grid until the end of 2024 and an additional 530MW until the end of 2031.[96] Reportedly, there are currently around 13GW of RES projects under development (mostly wind and solar power projects with up to 5GW) and for which the grid connection-approval process is ongoing. Hence, the technical limitation of the power grid may restrict and delay the development of the RES projects in Croatia.

To fully comply with the requirements of RED II, the new Act on Renewable Energy Sources and High Efficiency Cogeneration (*Zakon o obnovljivim izvorima energije i visokoučinkovitoj kogeneraciji*)[97] ("ZOIEVK") entered into force on 23 December 2021. A set of new implementing regulations remains to be adopted in the upcoming period. To date, the following new implementing regulations have been adopted: the Regulation on Share of Net Electricity Supplied by Eligible Generators and that Suppliers must Take Over from the Electricity Market Operator for 2023[98], which entered into force on 1 January 2022, and Decision on adoption of Energy Efficiency Programme for Energy Sector Decarbonisation[99], which entered into force on 23 December 2021.

Based on the old ZOIEVK from 2016, the following key implementing regulations apply: (i) the Regulation on Promoting the Production of Electricity from RES and High Efficiency Cogeneration ("RES Regulation")[100], which entered into force on 1 January 2019 and as amended on 23 May 2020, and (ii) the Regulation on Quotas for Promoting the Production of Electricity from RES and High Efficiency Cogeneration ("RES Quotas Regulation")[101], which entered into force on 16 May 2020 (see section F.2).

In addition, the implementing regulations that regulate the specific areas of RES and electricity generation apply, ie the Ordinance on Acquiring the Status of Eligible Electricity Generator[102], the Ordinance on RES Register and Preferential Producers[103], which entered into force on 21 September 2019, the Decision on Fee for RES and High Efficiency Cogeneration[104], the Regulation on Criteria for Payment of Reduced Fee for RES and High Efficiency Cogeneration[105], which entered into force on 1 July 2020, and the Decision on Fees for Using Space Used by Electricity Production Plants[106].

Croatia has introduced the Guarantees of Origin ("GO") and electricity disclosure obligations, in accordance with the requirements of RED. A GO issued within the Croatian system is an electronic certificate for the purpose of proving to final customers the share of or quantity of RES in an energy supplier's energy mix. On request of the eligible generator, who does not qualify for RES support system, GOs can be issued and traded on the market independently of the electricity generated. HROTE is entitled to issue GOs for delivered energy within the RES support system and guaranteed purchase price system, and to sell these GOs.

HROTE has been designated as a single competent body for issuing GOs in Croatia pursuant to the Regulation on Establishing the System of Guarantees of Origin of Electricity (*Uredba o uspostavi sustava jamstava podrijetla električne energije*)[107] and the Rules on Using the Registry of Guarantees of Origin of Electricity (HROTE of 16 April 2014 and HROTE of 29 September 2016) (*Pravila o korištenju registra jamstava podrijetla električne energije*).

The Registry of GO, which became fully operational in February 2015, implements a system for issuing, transferring, and cancelling GOs for electricity generated from RES and high-efficiency cogeneration. By the end of 2020, eight energy suppliers, three energy traders, and five electricity producers (ie a total of 16 users) had been registered with the Register of GO kept by HROTE.

The Methodology for Determining Origin of Electricity (*Metodologija utvrđivanja podrijetla električne energije*)[108] with effect from 21 November 2014, imposed obligations on suppliers regarding the disclosure of the origin of electricity to final customers and duties of HROTE as the market operator, the DSO, and the TSO regarding the residual mix calculation.

F.2 Renewable pre-qualifications

The ZOIEVK has introduced a new auction-based support scheme (ie Feed-In-Premium; "FIP") in Croatia, which replaced the previous Feed-In-Tariff ("FiT") scheme. On 9 December 2021, the European Commission approved the Croatia's RES state aid scheme for the period 2021-2023 in the form of a market premium granted to the winners of the auctions. The RES support mechanism will be introduced by way of market premiums which are going to be paid to RES producers on top of the (reference) electricity market price. The premium will be set through a competitive bidding process (auction).

Notably, Croatia will have a double-sided sliding FIP in place, similar to the components of a contract for difference ("CfD") mechanism. If the (reference) market price is below the CfD value (ie strike price under the contract), the plant operator will receive this difference as a premium; if the (reference) market price is above the CfD strike price, the plant operator will be required to pay back the difference to HROTE. HROTE will have a pre-emptive right in purchase at the reference price. The premium will be paid out for a period of 12 years.

Apart from the new FIP scheme, the ZOIEVK has also introduced an additional support scheme for small RES projects of up to 500kW, pursuant to which producers of such plants may conclude a power purchase agreement ("PPA") with HROTE at a guaranteed purchase price, if they are selected as best bidders in a tender carried out by HROTE.

According to the RES Quotas Regulation, the total support quota for all groups of RES production plants until 2023 is set at 2.265GW, out of which 210MW for solar power plants with installed capacity of more than 50kW up to 500kW, 240MW for solar power plants with installed capacity of more than 500kW up to 10MW, 625MW for solar power plants with installed capacity of more than 10MW and 1.050GW for wind power plants with installed capacity of more than 3MW. Under the approved RES state aid scheme for the period 2021-2023, Croatia intends to support a total capacity of 2,010 MW for electricity generation from wind, biomass, biogas, geothermal, solar, and hydropower plants up to 10 MW, with a connection capacity over 500 kW and innovative technologies.

The RES auctions for market premiums in Croatia are technology specific auctions. Based on the ZOIEVK, HROTE shall conduct auctions/public tender for the award of FIP at least once every three years and once per year for the award of PPA under guaranteed purchase price. HROTE will specify in a public call for tender which type of technologies are eligible and set the available auction volume/quotas from each type of technology (including, eg, wind, solar, biomass, biogas).

Generally, in Croatia it is not possible to participate in an auction for the award of market premiums simply with financial guarantees and an unmatured project. Only 'project holders' can participate in the public tender in accordance with the requirements set out in the ZOIEVK and the RES Regulation. The 'project holder' is a project developer that has obtained an energy approval permit for construction of the production plant, and which has been registered with the Croatian RES Register.

The RES project needs to be even further advanced in terms of development and must be either 'ready-to-build', which means that the developer must have obtained a valid building permit, or alternatively, the project must have obtained a valid location permit. However, in line with EU state aid law, the RES projects that are already in the construction phase are not eligible to participate in the auction. The reconstruction of an existing production plant can also be considered as a new production plant if it meets certain statutory conditions.

RES plants with a valid PPA concluded with HROTE under the old FiP support scheme or a valid PPA at a guaranteed price under new support scheme are not eligible to receive market premiums.

F.3 Biofuel

The legal framework for biofuel in Croatia is based on the Act on Biofuels for Transport (*Zakon o biogorivima za prijevoz*),[109] which deals with the production, trading, and storage of biofuels and other renewable fuels, the use of biofuels in transport, the adoption of the programmes and plans, and measures aimed at promoting biofuel production and use in transport. The law is aligned with RED II.

The main requirements of RED II and the Biofuel Directive have been included in secondary legislation, including the Ordinance on Measures for the Promotion of use of Biofuels in Transport (*Pravilnik o mjerama za poticanje korištenja biogoriva u prijevozu*),[110] the National Action Plan for the Promotion of Production and use of Biofuels in Transport 2010-2020 (*Nacionalni akcijski plan za poticanje proizvodnje i korištenja biogoriva u prijevozu za razdoblje od 2011-2020*), the Ordinance on the Sustainability Criteria in the Production and use of Biofuels (*Pravilnik o načinu i uvjetima primjene zahtjeva održivosti u proizvodnji i korištenju biogoriva*),[111] the Regulation on Special Environmental Fee for Non-Placing Biofuels on the Market (*Uredba o posebnoj naknadi za okoliš zbog nestavljanja biogoriva na tržište*),[112] the Regulation on Liquid Petroleum Fuel Quality (*Uredba o kvaliteti tekućih naftnih goriva*),[113] and the Regulation on the Quality of Biofuels (*Uredba o kakvoći biogoriva*).[114]

The production, wholesale, and storage of biofuels all require a 'licence for the performance of energy activities' (*dozvola za obavljanje energetske djelatnosti*) granted by HERA. No such licence is needed for biofuel retail sale, for its production exclusively for individual purposes, for production of up to 1 terajoule per year, or for storage exclusively for individual purposes.

Under the RRP, INA plans to construct a biorefinery facility in Sisak, with annual production capacity of 55 000 tonnes of advanced bioethanol by 2026, although a final investment decision has not yet been adopted.[115]

G. Climate change and sustainability

G.1 Climate change initiatives

Croatia has, to a large extent, implemented the EU Climate Change Package into its national legal system by adopting and amending regulations in the field of environmental protection and the energy sector (see sections F.1, G.2 to G.4, and H.3.).

Following the adoption of the Paris Climate Change Agreement in December 2015, Croatia is committed to implementing measures within the framework of EU obligations. Croatia has ratified the Paris Agreement, which entered into force on 23 June 2017.

The EU has made commitments to a clean energy transition, which will contribute to fulfilling the goals set out in the Paris Agreement on climate change to provide clean energy to all. To this end, the EU has set binding climate and energy targets for 2030: at least 40% cuts in GHG emissions from 1990 levels, at least 32% share for renewable energy in the energy mix, and at least 32.5% improvement in energy efficiency.

In line with the EU 2050 low-carbon framework and the United Nations Framework Convention on Climate Change ("UNFCCC"), Croatia's Low-Emission Development Strategy for the period to 2030, with a view to 2050, ie LEDS, was adopted on 2 June 2021. This sets out long-term goals (to 2050) for GHG emissions reduction, as well as implementing measures and financing arrangements. The LEDS is fully consistent with the Paris Agreement as it is prepared in line with commitments that Croatia has under the 2030 climate and energy framework.

With the aim to better regulate the competences and responsibility in mitigating climate change and to further align with the EU climate and energy framework, the new Act on Climate Changes and Ozone Layer Protection (*Zakon o klimatskim promjenama i zaštiti ozonskog sloja*)[116] and new Air Protection Act (*Zakon o zaštiti zraka*)[117] entered into force on 1 January 2020.

In accordance with the 2030 climate and energy framework, the Climate Changes Act provides for the obligation to develop the national Strategy for Adaptation to Climate Change for the period up to 2040, with an outlook to 2070 (*Strategija prilagodbe klimatskim promjenama u Republici Hrvatskoj za razdoblje do 2040. s pogledom na 2070. godinu*).[118] Accordingly, the Croatian Strategy for Adaptation to Climate Change, which defines measures by which the negative impacts of climate change are reduced, was adopted on 7 April 2020.[119]

In December 2020, Croatia has adopted its first integrated NECPs for the period 2021 to 2030. The NECP follows both the LEDS and the Energy Development Strategy of Croatia until 2030.

Croatia will participate with 45% in the EU's ambitious goal of a 55% reduction in GHG emissions by 2030. Croatia's coal phase-out year is 2033.

G.2 Emission trading

Croatia has been included in the EU Emissions Trading System ("EU ETS") since 1 January 2013. The legal framework for emissions trading in Croatia is set out in the Act on Climate Changes and Ozone Layer Protection, as well as in accompanying implementation regulations, such as, among others, the Regulation on the Monitoring, Policy, and Measures for Reduction of GHG Emissions in the Republic of Croatia (*Uredba o praćenju emisija stakleničkih plinova, politike i mjera za njihovo smanjenje u Republici Hrvatskoj*),[120] the Regulation on the Method of GHG Emission Allowance Trading (*Uredba o načinu trgovanja emisijskim jedinicama stakleničkih plinova*),[121] and the Ordinance on the Manner of Free Allocation of Emission Allowances to Installations and on the Monitoring, Reporting, and Verification of Reports on GHG Emissions from Installations and Aircraft (*Pravilnik o načinu besplatne dodjele emisijskih jedinica postrojenjima i o praćenju, izvješćivanju i verifikaciji izvješća o emisijama stakleničkih plinova iz postrojenja i zrakoplova*).[122]

The New EU ETS Directive and the Revised EU ETS Directive have been transposed into national law by provisions of the new Act on Climate Changes and Ozone Layer Protection with effect from 1 January 2020. Under the requirements of Climate Changes Act, a GHG emissions permit (*dozvola za emisije stakleničkih plinova*) issued by MGOR is required for the operation of existing installations for specified categories of industrial activities, as well as for new installations.

Emission allowances issued as of 1 January 2013 are managed in the EU Registry. MGOR, as the national administrator, is responsible for administrating user accounts opened in the EU Registry.

Installation operators must annually monitor and report emissions released from their installations; a verified report must be submitted to MGOR by 1 March each year.

In accordance with the Effort Sharing Regulation, Croatia agreed to a 43% reduction for EU ETS sector emissions. Croatia was permitted to increase emissions in non-ETS sectors until 2020, but must reduce these emissions by up to 7% by 2030 compared to 2005 levels.

G.3 Carbon pricing

In addition to participating in the EU ETS, Croatia has implemented the Regulation on unit charges, corrective coefficients, and detailed criteria and benchmarks for determining the charge for emissions of CO_2 into the environment (*Uredba o jediničnim naknadama, korektivnim koeficijentima i pobližim kriterijima i mjerilima za utvrđivanje naknade na emisiju u okoliš ugljikovog dioksida*)[123] which provides for the obligation to pay the carbon emission tax for all stationary sources emitting more than 450 tonnes of CO_2 annually from 2015. The obligated parties investing in energy efficiency, RES, and other measures to reduce carbon emissions and other GHG emissions pay a lower tax. The Environmental Protection and Energy Efficiency Fund (FZOEU) is authorised to calculate and charge the relevant amounts. As of 1 January 2013, the obligation to pay the carbon emission charge applies only to non-ETS sources.

The NECP indicated that the implementation of the measure is expected to continue in the period from 2021 to 2030 with modifications aimed at increasing efficiency. The possibility of including carbon emission tax in the price of fossil fuels for all non-ETS sectors will be considered, instead of the current carbon emission tax for stationary sources.

G.4 Capacity markets

Croatia has no capacity remuneration mechanisms in place.

H. Energy transition

H.1 Overview

The energy transition in Croatia is strongly driven by the EGD framework. The main national objectives, plans, and measures related to the energy transition are defined in the Croatia's Energy Sector Development Strategy, NECP, LEDS, and RRP. To be able to meet the 2030 climate and energy EU-wide targets and policy objectives for the period from 2021 to 2030, as well as to implement planned policies and investments, Croatia is planning to secure significant funding from available EU sources. Up to 37% of the funds from the Recovery and Resilience mechanism is earmarked for green transition.

H.2 Renewable fuels

Hydrogen

The NECP indicates that the role of hydrogen in energy and transport systems of the future is expected to be more significant. In line with the EU hydrogen strategy, Croatia's Hydrogen Strategy for the period until 2050 was formally adopted on 25 March 2022.[124]

The possibility of the use of renewable fuels such as hydrogen is already provided for in the Act on the Deployment of Alternative Fuels Infrastructure and the Act on Biofuels for Transport. However, the new legal framework is planned to be adopted to include new standards relating to hydrogen as an alternative fuel, including new technologies emerging in the process from hydrogen production to consumption as energy storage and alternative fuels. It is also necessary to build appropriate infrastructure for the production, distribution, and supply of hydrogen and at the same time support the procurement of vehicles, ships, and trains that use hydrogen as a fuel in order to create consumption.

Under the RRP, the objective is to install at least 10MW of renewable hydrogen electrolysers and six hydrogen refuelling stations until 2026 in Croatia. Croatia's Hydrogen Strategy sets more ambitious goals, ie, to install at least 70MW of renewable hydrogen electrolysers and 15 hydrogen refuelling stations by 2030, as well as to install a total of 2750MW of renewable hydrogen electrolysers and 100 hydrogen refuelling stations by 2050.

Ammonia

There are no relevant national strategies and legislative framework related to the current or planned use of ammonia as renewable fuel.

H.3 Carbon capture and storage

Although Croatia has technical and natural prerequisites for use of carbon capture and storage ("CCS") technology, there are currently no CCS projects in Croatia. Under the LEDS, the development of carbon capture and geological storage systems is seen as a transitional solution. CCS technology for large emission sources needs to be further developed and the potential and possibilities for this technology need to be considered at State level. It is therefore planned to prepare a study of storage capacity assessment, but also to prepare a National Feasibility Study with an action plan for preparatory activities for CCS projects. This study will cover the phases of capture at emission sources, transport, injection, and storage of CO_2, and the connection of the CO_2 transport system with other EU countries.[125]

Under the RRP, the pilot CCS project located next to a petrochemical industrial installation in Kutina is planned to be completed by 2026, with a capacity of 190 000 tonnes of CO_2 per year, and with a total of 5 million tonnes of CO_2 to be stored. In addition, another pilot CCS project is planned to be completed and operating with an annual storage capacity of 52 000 tonnes of CO_2 per year by 2026. It will be located next to the planned biorefinery facility in Sisak, with a total storage capacity of 6 million tonnes of CO_2.

The second round of transposition of the CCS Directive into national law was made in 2018 with the new Hydrocarbons Exploration and Production Act (*Zakon o istraživanju i eksploataciji ugljikovodika*)[126] ("ZIEU"), which came into force on 14 July 2018, and the Ordinance on Permanent Disposal of Carbon Dioxide in Geological Structures (*Pravilnik o trajnom zbrinjavanju ugljikovog dioksida u geološkim strukturama*),[127] which came into force on 3 November 2018.

H.4 Oil and gas platform electrification

In line with the EU Strategy on Offshore Renewable Energy, INA is, reportedly, planning to install offshore wind farms in the North Adriatic after gas production at its offshore platforms will be shut down in 2025.[128] Currently, there are no relevant national strategies and legislative framework related to offshore renewable energy.

H.5 Industrial hubs

Industrial hubs are not currently a feature in Croatia.

H.6 Smart cities

The LEDS indicates the need to implement a number of measures in the planning and construction of integrated systems in cities. These include public and other transport, buildings, utilities, autonomous systems, education systems, information and communication technologies (ICT), urbanism, innovative solutions in various fields, and raising public awareness.

The development of smart city infrastructure in Croatia is ongoing and is mainly supported by EU funds. Croatian cities (eg, Zagreb, Rijeka, Osijek, and Dubrovnik) are developing various smart city concepts and projects. As a strategic framework for the future development of the smart city, the City of Zagreb has adopted the Framework Strategy of the Smart City of Zagreb, 'Zagreb Smart City in February 2019'.[129] This framework strategy is focused on the following six strategic areas: digital infrastructure, efficient, transparent, and smart city administration, smart energy and utility management, education, the economy and sustainable urban mobility.

I. Environmental, social and governance (ESG)

Generally, there is an increased focus on environmental, social, and governance (ESG) issues both in Europe more widely and in Croatia. The EU-wide green taxonomy on environmentally sustainable activities is expected to further increase investments from the private sector in green and sustainable projects.

Endnotes

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32. Official Gazette of the RoC 'Narodne Novine' no. 84/22.
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Energy law in Cyprus

Recent developments in the Cyprus energy market

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Cyprus has ambitious plans for transitioning to a greener economy and for the development of a competitive electricity market. These plans involve promoting the increased use of renewable energy sources ("RES"), the use of natural gas for the generation of electricity, developing electricity storage solutions and ending the energy isolation of Cyprus by the promotion of interconnector projects.

Despite increasing production and use of RES, the Electricity Authority of Cyprus ("EAC") remains the dominant player in the Cyprus market. RES plants contributed only 12% of the total energy generated in 2020, whilst a small number of such plants have only last year extended their activities to supplying non-residential customers, taking up a 2% share of the supply market. Transmission and distribution remain monopolistic, even though there is now functional unbundling within the EAC, which is the owner of the distribution system and the owner and operator of the transmission system. Separated accounts are prepared by each of the regulated functions of the EAC as required by law and the Cyprus Energy Regulatory Authority ("CERA").

Operation of the electricity transmission system is entrusted by law to the independent Cyprus Transmission System Operator ("CTSO") which is responsible for the operation, maintenance and development of the system. The CTSO, and the EAC as distribution system operator ("DSO"), have been instructed by the CERA to consider whether the system should be redesigned to eliminate any technical constraints to increased penetration of RES and facilitate the installation of storage facilities. In March 2022, CERA specified by regulatory decision the basic principles for the establishment of ten-year development programme for the transmission and the distribution systems by the CTSO and the DSO respectively.

Promotion of storage facilities

The Ministry of Energy has prepared support schemes for the installation of storage facilities, whether autonomous or integrated with RES generation units. These schemes are subject to review by the European Commission. A competitive process is to be followed for the award of a licence for a central storage facility and it is unclear whether the EAC, which has expressed interest in participating in the competition, will be permitted to do so given its dominant position in other market segments. The CERA has already procured the amendment of the electricity market rules to facilitate the participation of storage facilities in the competitive wholesale electricity market.

Developing a competitive wholesale market

An interim but significant step towards having a competitive electricity market was taken in December 2020 when a transitory market was launched facilitating the conclusion of bilateral contracts between producers and suppliers notified to the CTSO as market operator. Despite long delays, the competitive market consisting of a central Day-Ahead Market and a forward market with bilateral over-the-counter contracts was expected to become operational in October 2022. There have been calls in recent months for a delay in the launch of the market and a revision of its operating model, which is based on the European Union's ("EUs") Target Model for electricity markets. Although the Ministry of Energy was determined to proceed as planned, a working group has been established by the Ministry with participants from CERA and the CTSO to consider the suitability of the selected model, given the current adversities in the international energy markets and high electricity prices. As a result, the launch of a competitive market may be delayed.

Ending the energy isolation of Cyprus

The end of the energy isolation of Cyprus is eagerly awaited (not least because it is estimated that it would support the higher penetration of RES by up to 50%). It is to be primarily achieved via the EuroAsia Interconnector project, which has been designated as a project of common interest ("PCI") under the EU's TEN-E Regulation. It consists of the interconnection of the electricity transmission systems of Israel, Cyprus and Greece with submarine cables and has a total capacity of 2,000MW. The project is described as an energy bridge between Europe and Asia and is expected to be commissioned in early 2026. In January 2022 it was announced that funding of €657 million will be provided by the EU, via the Connecting Europe Facility, to the EuroAsia Interconnector project, to support the first electricity interconnection between Cyprus and the European grid.

Similarly, the EuroAfrica Interconnector project is intended to link Egypt, Cyprus and Greece's electricity transmission systems with submarine cables and will have capacity to transmit 2,000MW in either direction. Commissioning for phase I (1,000MW capacity) is planned for December 2023. Although progress was reported on obtaining the necessary permits for construction work in Cyprus and on selecting a preferred engineering, construction and installation contractor in Egypt, no developments on the project have been reported since January 2021.

Reduction of electricity prices

Electricity generation in the EAC's three generating stations in Vasilikos, Moni and Dhekelia is still by fossil fuel, which results in high electricity prices for consumers due to the cost of acquiring greenhouse gas ("GHG") emission rights (the estimated cost of emission rights for 2022 for the EAC is €240 million and constitutes about 35% of the EACs production costs). The CERA, taking into account the political decision to achieve lower electricity prices, decided to reduce the final electricity prices by 10% for two months during the period from November 2021 to February 2022, with the reduction to be absorbed by EAC reserves. A similar decision had been taken by the CERA in 2020 to support consumers for a six-month period during the Covid-19 pandemic.

Natural gas reserves and LNG

Plans to introduce natural gas to Cyprus, which would reduce EAC costs by about 30%, have not to date materialised. Cyprus's own reserves, first discovered in 2015, have not been exploited. An exploitation licence was issued for the Aphrodite gas field (estimated 4.5Tcf) in 2019, but operations are still in the developmental phase. There is governmental support for the construction of a direct submarine natural gas pipeline to transport gas from Cyprus to the Xdku and/or Damietta liquified natural gas ("LNG") plants in Egypt, which are currently under consideration. The construction of a pipeline system to transport Eastern Mediterranean natural gas to the European markets, known as the EastMed, (currently a PCI under the New TEN-E Regulation) is also under consideration, but its economic viability was questioned by a US non-paper. The war in Ukraine has created new interest in these projects and their potential contribution to alternative supplies of gas for the EU. Final decisions by the project owners on both of these pipeline projects is pending.

Progress has been made in the development of an LNG terminal at Vasilikos on the south coast of Cyprus, which will include an LNG receiving and regasification facility, as well as storage facilities. Covid-19 and other factors have caused delays and increased costs, which have recently attracted media attention, but the Minister of Energy has assured that commissioning of the terminal is expected in 2023. The use of natural gas for the generation of electricity would commence soon thereafter upon completion of the pipeline systems that will link the LNG terminal with the EACs nearby generating station at Vasilikos itself, as well as its other two generating stations at Moni and Dhekelia.

Dhekelia generating station derogation

In February 2022, it was reported that the Dhekelia generating station can no longer benefit from a limited lifetime derogation under the EU's Industrial Emissions Directive (Directive 2010/75/EU) regarding compliance with prescribed emission limits under that Directive and related national implementing legislation, and this is expected to lead to fines for Cyprus and the EAC that would eventually be reflected in electricity prices. The derogation (which is available to certain combustion plants being part of a small isolated system and accounting in 2011 for at least 35% of the electricity supply within that system) was expected to apply until the end of 2023, but the Dhekelia station has already exceeded the permitted number of operating hours during the derogation period. Operation of the Dhekelia station should therefore cease but this is unlikely due to its significant contribution to electricity generation, operational safety and stability of the system and security of supply. The need for use of natural gas in electricity generation and for increased penetration from RES thus become all the more pressing.

Alternative fuels and RES

Green fuels like hydrogen have not yet been introduced. However, a Cyprus Hydrogen Association was founded in 2021 as a private initiative, the objectives of which include the utilisation of hydrogen technologies to play a key role in the energy transition, the contribution to the diversification of energy resources and the reduction of use of conventional fuels and GHG emissions.

A key RES is photovoltaic ("PV") for the production of electricity and solar thermal. PV has had widespread use in residential buildings, whilst a small number of wind farms have been operating for many years. With a view to promoting the orderly development of new RES projects, the Ministry of Energy has prepared a strategic environmental impact assessment study identifying the areas where such projects may be located, and this is under consideration by environmental authorities.

Complaints regarding the high cost of electricity prices for consumers have recently focused on the fact that RES producers that operate in the context of early support schemes (launched by the Ministry of Energy during 2005-2013) have contractually secured high long-term tariffs (applicable for 15 to 20 years) that significantly exceed the EACs avoidance cost payable to RES producers established under subsequent (2017-2018) support schemes or the prices agreed in bilateral contracts under the transitory wholesale market. The high returns for RES producers benefiting from fixed long-term tariffs has reportedly led to RES license trading. Suggestions that EAC should be permitted to invite competitive bids for the supply of electricity from RES to reduce average cost have met with CERA objections, given that the transitory regulation does not permit such bids on the basis that they might undermine the development of the competitive market. Nonetheless, by a regulatory decision issued in June 2022, CERA has temporarily fixed a ceiling for the price payable by EAC to RES producers operating under specific support schemes to cap their windfall profits. The possibility of a tax on such windfall profits is also under consideration by the competent ministry.

Revision of the national energy and climate plan and targets

The National Energy and Climate Plan issued in 2020 is currently being revised for the purposes of alignment with the EU's 'Fit for 55' package and aiming at climate neutrality by 2050. Cyprus has exceeded its 2020 RES target and it is foreseen that Cyprus will have no difficulty meeting its 2030 target. Achieving the RES-T targets is more challenging, given that the 2020 target was missed by 2.7%.

Developments in the transport sector

Efforts to reorganise public transport and promote the use of buses have not had substantial success in reducing private vehicle use. Attention has recently focused on governmental support schemes encouraging the acquisition of private electric vehicles and there are plans to gradually replace the governmental fleet of conventional cars with electric vehicles (including electric motorcycles for the Cyprus post office). The Ministry of Transport intends that at least 25% of new vehicle registrations each year will be electric vehicles and that the number will increase by 50% each year, to reach about 36,000 vehicles by 2030. Electric vehicle use will be supported by the installation of more than 1,000 recharging stations by 2026 in appropriate locations, such as governmental buildings, hospitals, museums, postal offices, restaurants, hotels, public spaces, parking places, petrol stations and highways. The government has secured €38.6 million from the EU's Recovery and Resilience Facility to finance these initiatives.

Another initiative is to promote the orderly use of electric bicycles and scooters, through legislation regulating of the micro mobility sector which was introduced in August 2022.

Additionally, it has been reported that Hermes Airports, the operator of the two international airports in Cyprus, endorsed in February 2022, the Toulouse Declaration – the first public-private initiative supporting European aviation's goal to reach net zero carbon dioxide (CO_2) emissions by 2050.

Energy efficiency and conservation

Finally, energy efficiency and conservation are being promoted by Ministry of Energy schemes, such as a scheme launched in December 2021 with grants to vulnerable consumers for the replacement of energy-intensive household appliances, such as refrigerators, air conditioning units and washing machines, by new energy-efficient appliances.

Initiatives by other ministries are also relevant, such as the National Framework Strategy for the Development of Smart Cities being prepared by the Deputy Ministry of Research, Innovation and Digital Policy. This is expected to support existing local initiatives, such as the Integrated Smart City Strategy 2018-2028 of Nicosia. Implementation of the capital city's strategy was launched in February 2021 and includes the installation of smart lighting, sensors monitoring environmental parameters, a smart waste monitoring system, development of an integrated system of sustainable mobility, traffic monitoring applications and smart parking solutions. Similar initiatives have been taken implemented in other local communities, like the municipality of Paphos.

Overview of the legal and regulatory framework in Cyprus

A. Electricity

A.1 Industry structure

The Electricity Authority of Cyprus ("EAC") is the key player in the electricity market. It is a public law body[1] that enjoyed statutory monopoly prior to Cyprus's EU accession in 2004. Although its monopoly in generation and supply has been abolished, the EAC owns and operates three power stations and is the owner of the transmission system and owner and operator of the distribution system. Functional unbundling has achieved segregation of the EAC's four regulated functions (generation, transmission, distribution and supply) and separated accounts are maintained for each function (also distinguishing between the EAC as owner and as operator of the distribution system).[2]

The Cyprus Transmission System Operator ("CTSO") is an independent public law body[3] exclusively responsible for operating the EAC-owned transmission system pursuant to the Regulation of the Electricity Market Law of 2021 (the "EML", which implements the recast Electricity Directive).[4] System development is ensured via a Ten-year Transmission System Development Programme ("TTSDP") prepared by CTSO and implemented by the EAC, according to the Transmission System Protocol (TSP) which facilitates cooperation between the parties. The TTSDP and TSP are approved by the Cyprus Energy Regulatory Authority ("CERA"), which is competent to monitor compliance and resolve any disputes.[5] CTSO is responsible for issuing the Transmission Rules, as well as Electricity Market Rules in its capacity as market operator, upon instructions from and subject to approval by CERA.[6] CTSO cannot engage in electricity generation, distribution or supply.[7]

Competition in the electricity market remains weak. The share of EAC-Generation has been gradually reduced from 99% in 2009 to 88% in 2020 with increasing production from RES,[8] but the EAC-Supply retains a 98% share of the supply market. A transitory regulation was introduced by CERA in 2017 to encourage participation by other producers and suppliers in the wholesale market, as an interim step in the process of setting up a competitive market. CERA's plans[9] for the launch of the competitive market by July 2019 failed to materialise, but preparations have progressed and the launch was planned for October 2022. It now appears that the launch may be delayed due to, among other things, the current turmoil in international energy markets caused by Russia's invasion of Ukraine and high energy prices, which have led to calls for postponing the launch and reconsidering the suitability of the selected market model under current conditions.

CERA is the regulator for the electricity and the gas markets. It is an independent public law body[10] and its objectives include promoting a competitive and environmentally-viable market, energy efficiency and integration of production from RES.[11]

CERA is responsible for issuing individual licences for electricity production, construction of production facilities or direct lines, supply of electricity to retail and wholesale customers, operating or owning a transmission or distribution system or an interconnector or storage facilities. Production facilities may instead operate pursuant to a general licence, provided they are autonomous, or their capacity does not exceed 20kW, or 30kW in case of own use, or 50kW in case of production from RES, or they are small scale units for the high-efficiency cogeneration of electricity and heat.[12] CERA has established the regulatory framework and terms applicable to general licences (which are effective following submission of the requisite notification to CERA and are valid for 30 years).[13] CERA may grant exemptions from the requirement for an individual or general licence where production is for own use and capacity does not exceed 1MW or production is from RES and capacity does not exceed 8MW.[14]

CERA's competences also include:

- monitoring compliance with applicable rules and imposing administrative fines;
- determining or approving pricing methodologies and/or tariffs for distribution and transmission; and regulating prices for generation, storage and supply for as long as effective competition is lacking;
- providing a dispute resolution mechanism for end-user complaints;
- cooperating with ACER and regulators in other member states; and
- advising the Minister of Energy, Commerce and Industry (the "Minister") on electricity-related matters.[15]

The Minister has overall responsibility for energy matters, including to contribute to the formation of energy policy and plans, such as the Integrated National Energy and Climate Plan ("NECP")[16] issued by the Council of Ministers. Pursuant to the EML, the Minister may take steps to intervene in the market, eg to:

- issue guidelines to CERA for establishing simplified licensing procedures for small-scale, decentralised and/or allocated production,[17] or for permitting prices that deviate from normal pricing rules to enable recovery of costs incurred;[18]
- issue policy guidelines regarding the provision of universal service (and may decide to extend that service to small enterprises)[19] or the operation of the electricity market and the establishment of market rules by CTSO (and may require a review of those rules by CTSO whenever deemed necessary);[20]
- issue orders setting out the procedure and terms for establishing a capacity mechanism[21] or decisions for the

imposition of public service obligations;[22]

- permit under appropriate conditions exceptional activity or system use, eg use of the distribution system by its owner for non-electricity related purposes, or ownership by the distribution system operator ("DSO") or CTSO of fully-integrated storage facilities;[23] and
- instruct CTSO to assess the potential for connection of the transmission system with other systems.[24]

A.2 Third party access regime

In line with the recast Electricity Directive, the EML provides that CERA shall ensure the implementation of a system of third-party access to the transmission and distribution systems based on published tariffs, applicable to all customers and applied objectively and without discrimination. The tariffs, or the methodologies underlying their calculation, must be approved by CERA and published prior to becoming effective.[25] Regulations issued by CERA set out the procedure for issuance of a pricing methodology and the approval of tariffs by CERA on the basis of proposals submitted by the operators.[26]

The operators may refuse access due to a lack of capacity by a reasoned decision based on objective, technical and economically justified criteria.[27] CERA is responsible for ensuring that those criteria are consistently applied and that a system user who has been refused access can make use of a dispute settlement procedure. The system operator must provide, where appropriate, on request and at a reasonable fee, information on measures that would be necessary to reinforce the network.

Producers and customers wishing to connect to the system must submit an application to CTSO or DSO. CTSO will only consider producer applications for capacity exceeding 8MW and customer applications for capacity exceeding 12MVA; applications for smaller capacity must be addressed to DSO. Applicants must meet the technical and safety requirements set out in detailed Transmission and Distribution Rules (a compilation of system rules prepared by CTSO and DSO respectively and approved by CERA). Applicants may be required to provide a bank guarantee to cover capital costs for work to be undertaken for their connection to the system. Successful applicants are invited to enter into a bilateral contract with the operator concerned and the proposed terms must be non-discretionary.

The EML provides for connection to the distribution system of RES plants or aggregator units with capacity up to 10.8kW (or 50kW provided network stability, reliability and safety are not affected) by a simple notification process, according to CERA regulations.[28] CERA has decided that notification from such producers to CERA concerning operation under a general licence (see section A.1) also serves as notification to the DSO for connection to the distribution system and that the relevant licence is effective as of the day of the producer's connection to the system.[29]

A.3 Market design

Although generation and supply are open to competition, the EAC remains dominant. Transmission and distribution are in effect statutory monopolies, and storage has yet to develop. CERA is responsible for the regulatory arrangements creating an appropriate market environment for activation of a competitive market. Under the transitory regulation introduced in 2017,[30] a wholesale market operating on the basis of bilateral contracts between producers and suppliers was activated in December 2020, via an online platform operated by CTSO for notification of the contracts between participants.[31]

The transitory regulation will cease to apply with the launch of the competitive market, planned for October 2022. Given the EAC's dominance, the arrangements for the competitive market, as detailed in CERA's regulatory statement issued in 2015,[32] allow for substantial regulatory intervention. CERA has approved the related Trading and Settlement Rules prepared by CTSO in its capacity as market operator ("MO").

The competitive market will operate on the basis of the Net Pool model and consist of a Day-Ahead Market ("DAM"), centrally managed by MO, and a forward market with bilateral OTC contracts. CERA will regulate the minimum participation of the EAC in the DAM to ensure adequate liquidity. There will also be an Integrated Scheduling Process and a real-time Balancing Mechanism to enable MO to procure reserves and activate balancing services, as well as a settlement process (see section C.1).

A.4 Tariff regulation

All tariffs and charges for services under the EML must reflect the cost for providing such services and be non-discriminatory. Deviation from this principle may only be permitted for cost recovery purposes, under a CERA decision according to guidelines by the Minister.[33] The EAC, CTSO and, for as long as there is lack of effective competition, any dominant undertakings involved in generation, supply or storage, must ensure that their tariffs and charges are set in accordance with CERA's charging methodology and are approved by CERA.[34] At least until 1 January 2025, the requirements of article 5 of the recast Electricity Directive on market-based supply prices do not apply to Cyprus.[35]

CERA must ensure that tariffs and charges permit the recovery by undertakings of all costs reasonably incurred in conducting their business in an efficient manner (including fuel cost, wages and salaries, operational and maintenance costs and depreciation, as well as any PSO and universal service costs), plus a reasonable return on capital employed ("ROCE").[36] When determining the appropriate level of tariffs and charges, CERA must take into account the protection of consumers against monopoly prices and the promotion of service efficiency and quality.[37] Charges by CTSO and DSO for connecting to or using the transmission or distribution system must be calculated in accordance with CERA regulatory decisions,[38] taking account of the capital cost of any new investment, so as to permit the operator to recover a share of the direct or indirect costs incurred and a reasonable ROCE.[39] Similar principles apply to the charges by MO relating to the operation and management of the electricity market.[40]

CERA issued a tariffs methodology[41] which was first applied for approval of 2017 electricity prices in the context of the transitory regulation. The aim is to create the framework for calculating prices reflecting the actual cost of services at the time of consumption for each of the regulated activities of generation by a dominant producer, transmission system ownership, transmission system operation, ownership and operation of the distribution system, and supply by a dominant supplier. The final price payable by consumers is the sum of the tariffs of these individual activities. The methodology determines the allowed revenues for each activity, and the form of the tariffs and their amount corresponding to the allowed revenues. In 2017 CERA approved the chargeable amounts of regulated tariffs and fixed the ROCE for 2017-2021 at 4.6% for each of the EAC's activities (generation, transmission ownership and distribution)[42] which was significantly lower than the rates under the previous methodology[43] (8% for generation and 6% for transmission and distribution).

A revised tariffs methodology prepared by CERA[44] will become effective upon implementation of the competitive market and the new market rules. The revised methodology introduces a tariff to be imposed in due course on producers for use of the EuroAsia interconnector (Cyprus-Greece segment, see section A.7) for the benefit of the interconnection line operator.

A.5 Market entry

Given the monopoly status for the owner and operators of the transmission and distribution systems, the licensing provisions of the EML effectively apply for generation and supply, as well as other functions such as storage, direct lines and interconnections. Unless the proposed activity can benefit from a general licence or exemption (see section A.1), a licensing application must be submitted to CERA. Only natural persons who are citizens of and resident in an EU member state and legal persons established in an EU member state may apply to CERA for a licence under the EML.[45]

The licensing process is outlined in the regulations issued by CERA.[46] Applicants must pay an application fee, which currently ranges from €170 to €1708 or, in the case of a licence for the construction or operation of generating station, €0.08543/kWh of generating capacity.[47] Applications are reviewed by CERA on the basis of objective, transparent and non-discriminatory criteria relating to, among other things, system security, energy efficiency, the nature of the energy source and the applicant's technical and financial capability.[48] The licences issued may include such non-discriminatory terms and restrictions as CERA considers necessary.[49] CERA must maintain a register of licensed entities which is open to public inspection.[50]

Rejection of an application by CERA is by written reasoned decision.[51] The decision is subject to review by the Administrative Court under article 146 of the Constitution. The review proceedings are not an appeal on the merits, but a check that CERA has not exceeded the limits of its authority or acted in a way that is plainly contrary to the EML.

Physical connection to the transmission and distribution systems is by application to CTSO or DSO, as appropriate. The EML requires the establishment of transparent and effective procedures, approved by CERA, for the non-discriminatory connection of new end customers, generation units and in-front-of-the-meter ("FtM") storage facilities.[52] Such procedures and technical and other requirements for applicants are set out in the Transmission and Distribution Rules. A simplified notification process for connection to the distribution system by small RES units has been introduced by CERA.[53] CERA has also requested the preparation by CTSO and DSO of a detailed techno-economic study for the redesign of the transmission and distribution systems during 2021-2030, to facilitate the installation of new RES units (by eliminating lack of capacity issues) and FtM storage facilities (by ensuring the network is flexible and bi-directional).[54]

Participation in the transitory wholesale market is by application to MO. The participants must hold an appropriate licence issued by CERA under the EML, as explained above, and participation floors apply of 50kW for producers and 10MW for suppliers. A guarantee must be provided by all participants for the benefit of MO who manages the credit risk on behalf of participants; the amount of the guarantee depends on historical data for the last six months, with a minimum of €100,000 for suppliers or €1,000 for producers (or, if greater, the estimated maximum negative balance for the participant concerned over a period of two months). An application fee of €800 is payable to MO and rejected applicants may raise an objection with CERA.

Participation in the competitive wholesale market will similarly require a licence from CERA, and an application to MO to become a contracting party of the Contractual Framework under the applicable Electricity Market Rules. A RES producer with capacity of less than 1MW per unit may only participate via a RES aggregator. The maximum total capacity of the portfolio of a RES aggregator cannot exceed 20MW (with no restriction on the number of RES producers that are represented by the RES aggregator's virtual unit). The Transmission and Distribution Rules that will apply were recently amended to enable the participation of FtM storage facilities in the competitive market.[55]

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The Minister, after consultation with CERA, may impose public service obligations ("PSOs") on any undertakings in the general economic interest.[56] PSOs must consider general social, economic and environmental factors (eg security, regularity, quality and price of electricity supply, energy efficiency, energy from RES and climate protection). PSOs must be clearly defined, transparent, non-discriminatory and verifiable, and ensure equality of access by all EU electricity undertakings to customers in Cyprus.

A PSO has been imposed on all electricity suppliers for the imposition of special lower prices to vulnerable customers, according to decisions by the Minister and CERA.[57]

Smart metering

The EML authorises CERA to determine the appropriate framework for the deployment of smart metering systems, with the aim of assisting active participation of customers in the market. Deployment is subject to a cost-benefit assessment to be undertaken in accordance with the principles laid down in Annex II of the recast Electricity Directive.

Following a cost-benefit analysis by EAC, CERA invited DSO to proceed with appropriate steps for the large-scale installation of smart metering systems, commencing in January 2019 and with the aim of installing 400,000 smart meters by January 2027.[58] CERA is competent to approve and publish the minimum functional and technical requirements for the systems to be deployed to ensure interoperability, accurate consumption measurements and data security.[59]

Electric vehicles

According to the Promotion and Development of Alternative Fuels Infrastructure Law of 2017 as amended (the "AFID Law"), which implements the Alternative Fuels Infrastructure Directive,[60] the relevant National Policy Framework ("NPF") issued by the Council of Ministers must provide for the installation of an appropriate number of publicly accessible recharging points for electric vehicles, taking into consideration the number of registered vehicles and recommendations by the European Commission.[61]

The EML[62] requires CERA to ensure that DSO facilitates the connection with the network of recharging station operators in a non-discriminatory way. Such operators are free to select and contract with any supplier. DSO is prohibited from owning and operating recharging stations, except for own use or with the permission of the Minister of Transport, Communications and Works provided and for as long as no other operators have been awarded the right to deploy recharging stations pursuant to a CERA-approved tender process.

In practice, a separated non-regulated function of the EAC (not EAC as DSO) has undertaken the deployment of recharging stations, pursuant to a CERA-approved agreement with EAC-Supply,[63] and there are currently about 60 publicly accessible charging points. According to the National Framework Policy for the Promotion of Electric Vehicle Use, the target is to have more than 1000 stations by 2026 in appropriate locations, such as governmental and public buildings, parking places, petrol stations and highways. Schemes recently launched subsidising the purchase of electric vehicles should contribute to achieving the target of having about 36,000 registered electric vehicles by 2030, and so should the decision for the gradual replacement of existing governmental vehicles with electric vehicles.

The installation of private charging stations has also been encouraged via a RES Fund scheme for subsidising the installation cost at the premises of persons owning an electric vehicle and already having or wishing to also install a photovoltaic ("PV") unit on a net-metering basis.[64]

A.7 Cross-border interconnectors

There are currently no cross-border interconnectors with other countries. However, there are two interconnection projects which, if implemented, will end the energy isolation of Cyprus and connect its system with the pan-European electricity grid.

The EuroAsia Interconnector, designated as a PCI under the new TEN-E Regulation,[65] consists of the interconnection of the transmission systems of Israel, Cyprus and Greece with submarine cables and will have a total capacity of 2000MW.[66] The project has obtained funding from the EU's Connecting Europe Facility and its expected commissioning is in early 2026.

The EuroAfrica Interconnector will link the transmission systems of Egypt, Cyprus and Greece and will have capacity to transmit 2000MW in either direction. Commissioning for phase I (1000MW capacity) was expected in December 2023, but little progress has been reported during the last year.[67]

B. Oil and gas

B.1 Industry structure

There is no developed gas market in Cyprus. There is no production yet from reserves discovered within the Cyprus EEZ (see section E.) and plans for the importation of LNG have taken long to materialise. The state-owned Natural Gas Public Company Limited ("DEFA") (soon to be converted from a private company to a public law body)[68] has been designated by the Council of Ministers as the sole importer and distributor of gas in Cyprus for as long as Cyprus will qualify as an emergent market under the Third Gas Directive (ie for ten years from the first commercial supply of gas under the first long-term supply contract for the market) and is responsible for the construction and operation of an LNG receiving, storage and regasification terminal at the Vasilikos area on the south coast of Cyprus. In June 2019, DEFA was designated by a decision of the Council of Ministers ("CoM Decision")[69] as transmission system operator ("TSO"), operator of the LNG facility and DSO for a period of 30 years from the issuance of the relevant licences by CERA.

To further the objective of using gas for electricity generation in Cyprus, DEFA has established the Natural Gas Infrastructure Company ("ETYFA") (currently with 30% participation by EAC). ETYFA has concluded a contract with an international consortium for construction of the LNG terminal, including a floating unit for storage and re-gasification of LNG. Although work was initially expected to be completed by early 2022, so that use of gas for electricity production by the EAC would commence soon thereafter, the commissioning date has gradually slipped to the first semester of 2023. DEFA has obtained licences from CERA pursuant to the Regulation of the Natural Gas Market Law of 2004, as amended (the "GML") for the operation of the LNG terminal and for the construction, ownership and operation of the gas transmission system. Pipelines will first link the terminal with the EAC's generating stations and thereafter the system will develop to facilitate supply of gas to other industrial and commercial users (for which further CERA licences would be needed). Negotiations are also expected to commence in due course with pre-selected candidates for the conclusion of sale and purchase agreements with a three to five-year horizon for the acquisition of basic quantities of gas, as well as master sales agreements for entry into supplementary spot transactions.

The GML establishes the legislative framework for the gas market and has been revised to implement the Third Gas Directive and Directive (EU) 2019/692.[70] CERA is the regulator responsible for issuing licences (in respect of construction of a pipeline network or other facilities, storage, transmission, distribution or supply of gas), promoting effective competition and smooth functioning of the market and monitoring compliance by gas undertakings with applicable requirements on matters such as transparency, system maintenance, safety and quality.[71] CERA may issue regulatory decisions, impose administrative fines and amend or revoke licences. CERA has issued Rules on the Supply of Gas (addressing matters such as the content and entry into supply contracts, invoicing and settlement, complaints handling, types of customers and reporting to CERA).[72]

The Council of Ministers is responsible for designating or requiring the designation of a TSO, LNG facility operator and DSO, who are each responsible for compliance with operator obligations under the GML (on matters such as system maintenance and development, non-discrimination between system users, transparency of information and access).[73] Where DSO is part of a vertically integrated undertaking ("VIU"), DSO must be independent in terms of organisation and decision making from other activities not relating to distribution (but asset ownership unbundling is not required and legal form independence is up to the Council of Ministers to decide).[74] The same requirement applies for TSOs except that legal form independence is also required.[75] Gas undertakings must maintain separated accounts for each of their activities (transmission, distribution, supply, LNG and storage)[76] and CERA has issued regulatory decisions requiring the submission to CERA on an annual basis of separated regulatory accounts and providing detailed guidance on account preparation.[77]

Pursuant to the Third Gas Directive, Cyprus may rely on derogations from certain regulatory provisions (on matters such as licensing and unbundling) for as long as it qualifies as an emergent and/or an isolated market. The Council of Ministers is empowered by the GML[78] to decide on such derogations for as long as:

- Cyprus is not directly connected to the interconnected system of any other EU member state and has only one main external supplier, ie a supplier having a market share of more than 75% (in which case Cyprus will be an "isolated market"); and/or
- the first commercial supply of gas in Cyprus in the context of its first long-term supply contract is made not more than 10 years earlier (in which case Cyprus will be an "emergent market").

Pending the characterisation of Cyprus as an isolated and/or emergent market, CERA is expressly authorised to refrain from issuing any licences under the GML.

According to CERA's Statement of Regulatory Practice and Pricing Methodology for Natural Gas, issued in June 2019 (the "2019 Regulatory Statement"),[79] and in line with the CoM Decision for derogation on the basis of emergent market status, there will be a monopoly regarding the importation and the supply of gas to all users for as long as this status applies. For the same period there will be derogation from GML provisions on TSOs organisational independence and DSO's legal form and organisational independence, separated accounts, third party access and direct supply to eligible customers.[80] Regulations have been prepared by CERA on the operation of the market during the derogation period, but these have not yet been issued.[81]

B.2 Third party access regime to gas transportation networks

Under the GML, third party access to the transportation and distribution system will be ensured through the publication of tariffs applicable to all system users in an objective and non-discriminatory manner.[82] Operators of transportation and distribution systems must provide users with all information needed for effective access. The tariffs and terms for the provision of services by operators must be non-discriminatory and approved by CERA.[83]

An operator may refuse access on account of lack of capacity or conflict with any public benefit obligations imposed by CERA. Refusal must be duly reasoned.[84] CERA may take measures to ensure that, where access is denied due to lack of capacity or of interconnections to the system, the operator takes action to improve the system where this would be financially possible, or the potential customer is willing to cover the cost.[85]

B.3 LNG terminals and storage facilities

An LNG terminal, including a floating unit for storage and re-gasification, is under construction in Vasilikos and currently expected to be completed by mid-2023 (see section B.1). A licence by CERA under the GML is required and has been obtained for this purpose.

Under the GML,[86] third party access to LNG facilities will be ensured through published tariffs approved by CERA and applicable to all users in an objective and non-discriminatory manner. Operators must provide users with all information needed to ensure effective access to the facilities. The terms for services by operators must be non-discriminatory and approved by CERA.

The GML provides[87] for regulated access to storage facilities when technically and/or economically necessary for efficient access to the system for the supply of customers. Regulated access would be on the basis of objective, transparent and non-discriminatory criteria defined by CERA. CERA regulations would set out the technical specifications for those seeking access; promote efficient and economical use and development of storage facilities; and require public disclosure by operators of the facilities which are offered for access. Access by gas undertakings and eligible customers would be on the basis of published tariffs and/or other terms and obligations relating to the use of storage facilities. CERA must consult with system users before developing those tariffs or the methodologies for those tariffs. The right of access for eligible customers may be given by enabling them to enter into supply contracts with competing undertakings other than the owner and/or operator of the system or a related undertaking.

B.4 Tariff regulation

Under the GML, third party access to the transportation and distribution system and LNG facilities would be ensured through CERA-approved published tariffs applicable in an objective and non-discriminatory manner to all system users.[88] CERA is competent to issue regulations with appropriate measures for the protection of end users, including vulnerable customers, which should ensure that transparent information on current prices and tariffs and on the applicable terms and conditions is made available to the public and end users.[89]

According to the 2019 Regulatory Statement, prices for the supply of gas to users will be approved by CERA per category of customer. The supply contracts will set out the price which will cover the cost of supply as well as the cost of use of gas facilities and will include a reasonable profit margin for the supplier. CERA will also approve prices for the use of gas facilities and decide on the allocation of the cost of use of all facilities to the various categories of customers taking into account the allocation proposed by the supplier. This arrangement and CERA's Regulatory Statement will be revised when Cyprus is no longer an emergent market and, for the purposes of transition to a free market, supply will be unbundled from other activities and eligible customers will be specified. The stated aims of the current pricing regulation include facilitating the introduction of gas to the Cyprus market for the benefit of consumers and the environment, satisfying public service obligations and ensuring security of supply. Tariffs should reflect the cost of service, permit the recovery of costs and promote the development of gas infrastructures, be transparent, fair and non-discriminatory, encourage efficient consumption by users, efficient operation by gas undertakings (avoiding, to the extent possible, cross-subsidisation between various activities) and be consistent with environmental targets. The competitiveness of gas prices when compared with alternative fuels should be ensured. The separation of accounts and operations of DEFA as operator of the system and as supplier of gas must be ensured so that costs are separately recorded and allocated accordingly.

B.5 Market entry

Market participants (owners and/or operators of receiving, storage and regasification terminals, owners and/or operators of transmission or distribution systems and gas suppliers) are subject to a licensing requirement under the GML. Applications for licences are submitted to CERA, in accordance with regulations issued under the GML.[90] An application fee is payable, which ranges from €170 to €855 or, in the case of a licence for the construction or operation of an importation, storage or re-gasification terminal, €0.08543 per 100 cubic meters of annual capacity.[91]

CERA's decision on whether to grant a licence would be made by taking into account the criteria set out in the GML and any directives issued by the Minister. These include system safety, environmental protection, efficient energy use and the applicant's technical, financial and other qualifications.[92] The licences issued may include such non-discriminatory terms and restrictions as CERA considers necessary.[93] An application for construction and operation of a new distribution pipeline system may be rejected by CERA in respect of a particular area where such pipeline systems have already been or are proposed to be built in that area provided existing or proposed capacity is not saturated.[94]

Rejections must be reasoned and notified by CERA to the applicant in writing within 30 days.[95] Review proceedings against the rejecting decision may be initiated before the Administrative Court under article 146 of the Constitution, which serve as a check against potential abuse of authority or error of law (and not as an appeal on the decision's merits).

Pending characterisation of Cyprus as an isolated and/or emergent market, the GML empowers CERA to refrain from issuing any licences.[96] According to CERA's 2019 Regulatory Statement, and in line with the CoM Decision for emergent market status, there will be a monopoly regarding the importation and supply of gas to all users for as long as this status applies. In practice, the only licences that have been issued by CERA are to DEFA (the designated sole importer and distributor of gas) in respect of the construction and operation of the gas transportation system and the Vasilikos LNG terminal. Market entry by other entities is therefore unlikely at least whilst the emergent market status applies (ie for ten years from the first commercial supply of gas under the first long-term supply contract for the Cyprus market).

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Under the GML,[97] the Minister may instruct CERA to impose public service obligations on any licensee. Public service obligations may include obligations in relation to the security, regularity, quality and price of supply and environmental protection (climate protection and energy efficiency). Obligations must be clearly defined, transparent and objective and ensure equal access of all EU undertakings to customers in Cyprus.

It is one of CERA's objectives to ensure that gas undertakings optimise the use of gas, for example by introducing intelligent metering systems where appropriate, which would promote the active participation of consumers in the supply market.[98] An assessment as to which form of intelligent metering is economically reasonable and cost-effective and which timeframe is feasible for their distribution would be prepared by the undertaking and submitted for CERA's approval. CERA shall ensure the interoperability of implemented systems, having regard to the use of appropriate standards and the importance of development of the gas market. Where smart metering is to be introduced, CERA shall ensure that the systems provide end customers with real time data and enable accurate invoicing according to actual consumption verifiable by customers on the basis of readily accessible historic data, whilst safeguarding data security and customer privacy.

B.7 Cross-border interconnectors

Cyprus does not have cross-border interconnectors. An intergovernmental agreement[99] has been concluded between Cyprus and Egypt regarding the proposed construction of a direct submarine pipeline that will transport gas from the Cyprus EEZ to LNG plants in Egypt. In addition, an intergovernmental agreement[100] has been concluded between Cyprus, Israel, Greece and Italy concerning a pipeline system to transport Eastern Mediterranean gas to the European markets (known as EastMed). The EastMed project is a PCI under the new TEN-E Regulation,[101] but a formal decision by the project owners to proceed is pending.

Major new infrastructure, including interconnectors, may upon request be exempted, for a defined period, from specific provisions of the GML relating to, among other things, unbundling of transmission systems and operators; designation of a TSO; and third party access to transmission systems.[102] The decision on exemption is made by CERA following consultation with the competent regulators of (i) member states the markets of which are likely to be affected by the infrastructure and (ii) third countries from or in which the infrastructure originates or ends.

As of August 2020, the commencement of negotiations with a non-EU country in order to conclude, amend or renew an agreement on the operation of a gas transmission line and execution of the related agreement may only proceed with European Commission authorisation pursuant to Directive (EU) 2019/692.[103]

C. Energy trading

C.1 Electricity trading

The EML provides for non-discretionary Electricity Market Rules (the "EM Rules"), issued by CTSO and approved by CERA, which govern the mechanisms, prices and other terms for electricity trading on the basis of arrangements made by CTSO.[104] The EM Rules are binding on all market participants and have been revised for the purposes of the transitory regulation for the wholesale market.[105] The transitory market was activated in December 2020 by launch of a dedicated online platform, operated by CTSO as MO, for notification of bilateral contracts between producers and suppliers. Contracts are notified up to three business days before the beginning of the month, during which delivery will occur, and are settled on a monthly basis. The EAC does not participate, but is responsible for absorbing the total imbalance of production and consumption. Settlement and pricing are regulated by procedures prescribed by CERA.[106] There are currently 25 participants (two suppliers and 23 producers).[107]

The transitory regulation will cease to apply with the launch of the competitive market planned for October 2022. The competitive market will operate on the basis of the Net Pool model as detailed in CERA's regulatory statement issued in 2015.[108] It consists of a central DAM and a forward market with bilateral OTC contracts as a risk management tool. DAM will be centrally managed by CTSO as MO and CERA will regulate the minimum participation of the EAC with a view to enforcing adequate liquidity. The design is supplemented by an Integrated Scheduling Process ("ISP") and a real-time Balancing Mechanism, to enable the procurement of reserves and the activation of balancing services, as well as a settlement process. An Intra-Day Market will be developed at a later stage to further support market operations.

Specifically, bilateral physical forward contracts will be notified and corresponding schedules nominated to MO by OTC market gate closure on the day ahead. Suppliers and generators will provide bid curves to the DAM on a half-hourly basis. Orders in the DAM will be unit based in the case of producers (or per RES plant or RES aggregator). Suppliers will submit orders based on individually forecast demand. Orders in the DAM should correspond to quantities not already covered by bilateral contracts and take into account any prior replacement reserve commitments. MO will run a process of matching bid curves to optimise dispatch of residual volumes at the day ahead. Contracts resulting from the DAM will be between market participants and MO at the DAM clearing price.

The central ISP, which will take place during the afternoon of D-1, will facilitate the procurement of operating reserves on a more cost-effective basis, by allocating reserve requirements to production units closer to real time and ensuring the system's technical feasibility. Participation in the ISP's daily auctions will be mandatory for all conventional units with an installed capacity exceeding 5MW, and all units should submit bids and offers for balancing energy corresponding to their entire capacity including volumes committed under the forward market and/or the DAM. RES plants with appropriate technical capabilities may participate in the balancing mechanism on a voluntary basis. Participants' positions as instructed by MO following the ISP are indicative and do not involve any economic settlement. During balancing in real time, MO's final dispatch orders will be formulated which will produce economic results for participants.

Cyprus does not participate in EU market coupling, given the absence of interconnectors.

C.2 Gas trading

There is currently no gas trading in Cyprus.

D. Nuclear energy

There are no installations for the generation of nuclear energy in Cyprus. Cyprus is a member of the International Atomic Energy Agency ("IAEA") and Euratom and the IAEA-Euratom safeguards agreement applied to Cyprus since May 2008.[109] The Nuclear Safety Directive[110] has been implemented by the Protection against Ionising Radiation and on Nuclear and Radiological Safety and Protection Law of 2018, which also implements Euratom directives on ionising radiation and the management of radioactive waste,[111] as well as General Safety Requirements of the IAEA.[112]

E. Upstream

The exploration and exploitation of oil and gas reserves in Cyprus is regulated by the Hydrocarbons (Prospecting, Exploration and Exploitation) Law of 2007, as amended (the "Hydrocarbons Law", which implements the Hydrocarbons Licensing Directive)[113] and related regulations. Licences are issued by the Council of Ministers in respect of specific exploration blocks offshore Cyprus pursuant to a competitive licensing process. Exploration licences are issued for up to three years and may be renewed for two additional periods of two years each, provided there has been compliance with the terms of the licence and the related production sharing contract ("PSC") between Cyprus and the licensee. An exploitation licence is issued in respect of a commercially exploitable discovery, on the basis of an approved development and production plan, and has an initial term of up to 25 years and may be renewed for a term of ten years. Model PSCs have been issued by the Minister, which are the basis of negotiations with prospective licensees. Transfer or assignment of a licence is subject to approval by the Council of Ministers, which is granted on the basis of criteria of technical knowledge, experience and financial resources of the proposed transferee. The conduct of hydrocarbons operations is subject to various requirements, including in relation to health, safety and environmental protection. The Offshore Safety Directive[114] has been implemented via an amendment to the Hydrocarbons Law and by the introduction of a separate piece of legislation, the External Emergency Response Plans in Offshore Oil and Gas Operations Law of 2016.

Cyprus has entered into agreements with Egypt, Lebanon and Israel on the delimitation of its EEZ to facilitate hydrocarbons operations. A number of exploration licences have been issued since 2008 and there are currently nine licensed blocks. There is only one exploitation licence for the Aphrodite gas field (estimated 4.5Tcf) discovered in 2015 in block 12. The licence was issued in 2019 following approval of the related development and production plan which envisages the transfer and sale of gas to Egypt via a subsea pipeline. Further discoveries of gas have been made in blocks 10 and 6 (initial estimated quantities of 5 to 8Tcf and 2.5TcF respectively, although not yet confirmed).

F. Renewable energy

F.1 Renewable energy

RES are primarily regulated by the Promotion and Encouragement of the Use of Renewable Energy Sources Law of 2022 (the "RES Law"), implementing the RED II.[115] The RES Law sets the minimum share of energy from RES in the gross final consumption of energy in Cyprus as of 2021 at 13%, while the national target of 23% RES-E for 2030 is set out in the NECP.[116] This is separately supplemented by a national target for the share of energy from RES in transport (RES-T of 14% for 2030).[117]

The Council of Ministers is competent to take steps for the achievement of the national targets, upon proposals by the Minister, primarily through the establishment of support schemes encouraging the use of RES.[118] Any such schemes encouraging the use of RES for electricity generation are subject to prior consultation with CERA. Support schemes have promoted on-site production from RES for own consumption for both residential and business consumers (net metering). They have also been extended to net billing schemes for industrial and commercial consumers whereby credit is received for any excess power injected back into the grid.

The Renewable Energy Sources and Energy Conservation Fund (the "RES Fund")[119] has been established with the purpose of providing grants or subsidies for investment or activities promoting RES and energy conservation. The major source of funds for the RES Fund is a levy on electricity consumption payable by all persons connected to the electricity distribution network. Currently the levy is €0,005/KWh consumed, but vulnerable household consumers only pay half this rate.[120] Specific schemes are launched by the RES Fund from time to time and have included subsidisation of the production of electricity by RES (installations of PVs, biomass and wind farms connected to the EAC distribution system) and the installation of solar thermal systems on household premises.

The RES Law also establishes a One-Stop-Service facilitating the authorisation of RES projects[121] and includes provisions for the promotion of self-consumption of electricity from RES[122] and the operation of renewable energy communities[123] where consumers, SMEs and local authorities jointly participate in the development of RES projects.

F.2 Renewable pre-qualifications

Each support scheme promoting the use of RES specifies the criteria that must be met by applicants. Schemes currently open are for the installation of net-metering photovoltaic ("PV") systems with capacity up to 10KW, or net-billing RES systems with capacity up to 8KW, and these are available to all consumers (residential and non-residential) connected to the grid. A separate scheme for PV systems connected to the grid via virtual net metering (whereby production by the PV system is netted with consumption of premises other than those in which it is located) is available to residential consumers (maximum capacity of 10KW) and professional farmers (maximum capacity of 20KW). There is also a scheme open to all consumers for the installation of RES systems for self-production and self-consumption with no capacity limitation and no requirement for connection to the grid.[124] In addition, schemes launched by the RES Fund currently include part-subsidisation of the cost of installation of net-metering or virtual net-metering PV systems in residential premises for which the planning permit had been issued prior to 2017; the schemes are open to all individual consumers, with higher subsidies available for vulnerable consumers and residents of mountainous areas.[125]

F.3 Biofuel

The Specifications, Sustainability Criteria and Reduction of Emissions from Fuels Law of 2022 (the "Fuel Specifications Law"), implements the Fuel Quality Directive and related provisions of RED II. This authorises the Minister to issue decrees on, among other things, fuel content specifications. A decree already issued by the Minister regulates the blending rate of biofuels in conventional transport fuels, which is currently set at 7.3% in terms of energy content.[126] Biofuels are counted for the purposes of compliance by suppliers only if they meet the sustainability criteria set out in the Fuel Specifications Law,[127] which relate to greenhouse gas ("GHG") emission savings and the protection of certain types of land (eg with high biodiversity value or high-carbon stock) from use for the production of raw materials for biofuels. Biofuel produced from waste and residue need only comply with the GHG emission saving requirements and is double counted when calculating whether the blending rate has been achieved.[128]

The Fuel Specifications Law requires suppliers to reduce life cycle GHG emissions per unit of energy from fuel and energy supplied by 6% each year after 2020.[129] In addition, to ensure that the RES-T target of 14% for 2030 is achieved, the Minister may fix the share of energy from biofuels, bioliquids and biomass fuels produced from certain types of crops at not more than 1% above the share of such fuels in final energy consumption in transport in Cyprus in 2020, subject to a cap of 7%.[130]

The biofuels currently used in Cyprus are biodiesel from used cooking oils, hydrotreatment vegetable oils and bio-ethers. Bioethanol is deemed unsuitable for use with petrol due to its volatility and the high temperatures prevailing in Cyprus.[131]

G. Climate change and sustainability

G.1 Climate change initiatives

The contribution of RES to final consumption has more than doubled since 2011 reaching 17% in 2020 (thus exceeding the RES-E target of 13%). More than €350 million of subsidies and grants were paid by the RES Fund to businesses and households from 2005 to 2020 to encourage investment in RES,[132] and the RES-E target of 23% by 2030 is deemed achievable. RES production will participate in the competitive wholesale market to be launched in October 2022, and steps are taken to remove technical constraints to increased penetration of RES, by redesigning the existing electricity system, facilitating the deployment of storage technologies and promoting interconnection with neighbouring countries (eg via the EuroAsia Interconnector).

Use of RES in heating and cooling is promoted by support schemes for households and public buildings and obligatory measures for new buildings. Increased RES in transport is most challenging, given the 7.3% contribution of RES-T in 2020 (short of the 10% target). Measures intended to support meeting the 14% RES-T target for 2030 include the introduction of support schemes for local biofuels production from waste and the use of natural gas in public transport, eg via converting the existing bus fleet for CNG-use once available in Cyprus.[133]

G.2 Emission trading

The Establishment of Greenhouse Gas Emission Allowance Trading Scheme Law of 2011, as amended (the "ETS Law") implements the EU ETS Directive and facilities application of related EU decisions and regulations, including on the allocation of allowances and the auctioning platform.[134] The Minister of Agriculture, Natural Resources and the Environment (the "Minister of Agriculture") is competent to issue GHG emissions permits for stationary installations and allocate GHG emissions allowances for aviation activities.[135] Operators must monitor and report emissions, and surrender, by 30 April of each year, a number of allowances equal to their total emissions during the preceding calendar year.[136]

Cyprus participates in the EU ETS and there is no national emission trading scheme. Allowances (other than those allocated free of charge pursuant to the ETS Law [137]) are allocated by auctions[138] executed via the European Energy Exchange as the common auction platform under the EU ETS. The Cyprus Stock Exchange is the appointed auctioneer responsible for running the auctions and collecting the proceeds for Cyprus. Small installations may be excluded from the EU ETS if subject to measures that achieve an equivalent contribution to emission reductions.[139]

G.3 Carbon pricing

Carbon pricing and the 'emitter pays' principle is reflected in policies other than emissions trading. For example, as of 2014, carbon dioxide ("CO_2") emissions are taken into account when calculating annual circulation fees payable in respect of motor vehicles.[140]

According to the NECP, there are plans for a green tax reform that would involve carbon pricing in non-ETS sectors of the economy, to stimulate energy efficiency and substitution of liquid fossil fuels by low- or zero-carbon energy forms. Similarly, there is discussion concerning the introduction of a mandatory producer's responsibility scheme for recovered fluorinated GHGs pursuant to legislation supplementing the relevant EU regulations.[141]

G.4 Capacity markets

Adequacy of supply concerns have not arisen to date, given the near-monopoly status of EAC-Generation and the capacity of its generating stations which has been sufficient to meet demand. Should concerns arise with the upcoming development of the competitive market, a temporary capacity mechanism may be introduced by the Minister[142] in line with the provisions of the recast Electricity Regulation,[143] following consultation with CERA and CTSO and with the consenting opinion of the European Commission. CERA is responsible for conducting the requisite resource adequacy assessment, consulting with the Minister and publishing the terms of and running the competitive process for the selection of capacity providers.[144]

H. Energy transition

H.1 Overview

The NECP sets out national quantitative energy and climate targets for 2021-2030 and polices to achieve an increased share of RES in energy consumption (see section G.1), increased energy efficiency and reduced GHG emissions. The relevant targets (other than as mentioned in G.1) include:

- reduction of emissions in ETS sectors by 24.9% and in non-ETS sectors by 20.9% compared to 2005, and emissions from land use, land use change or forestry to be offset by at least an equivalent removal of $CO_2$from the atmosphere; and
- 13% reduction in final energy consumption and 17% in primary energy consumption, compared to 2007, achieving a cumulative saving of 243.04ktoe during 2021-2030.

Initiatives to promote energy efficiency and reduce GHG emissions include measures to improve the thermal behaviour of buildings (eg compulsory thermal insulation for new buildings and energy upgrade of existing public buildings and infrastructure); promotion of hybrid, electric and low-emissions vehicles; reorganisation and promotion of the use of public transport (buses); improved monitoring of GHG emissions in agriculture; recycling; and promotion of use of energy-efficient appliances and lighting bulbs.

H.2 Renewable fuels

There is no infrastructure for use of hydrogen or ammonia as fuels in Cyprus and the potential of such use is not currently addressed in the NECP or NPF. The AFID Law provides the legal framework for the deployment of hydrogen in road transport and for making an appropriate number of hydrogen refuelling points for motor vehicles accessible to the public by 31 December 2025 but only to the extent that the Council of Ministers will decide to introduce such an objective in the NPF.[145]

H.3 Carbon capture and storage

The CCS Directive has been implemented by the CO_2 Storage in Geological Formations Law of 2012, as amended (the "CCS Law"). The Minister of Agriculture is competent to determine the areas from which storage sites may be selected[146] and, after such determination has been made, to issue exploration and storage permits to applicants pursuant to public and non-discriminatory procedures.[147] Permits can be issued provided all applicable technical and financial requirements are satisfied and the views of the European Commission are taken into account.[148]

Operators of storage facilities must establish a financial guarantee or equivalent security to ensure compliance with their obligations, which must remain valid until responsibility for the site is transferred to the Minister of Agriculture according to the CSS Law. In case of fault on the part of the operator, the Minister of Agriculture may recover from the former operator costs incurred after the transfer of responsibility.[149]

There is no decree determining areas for storage sites and no storage facilities in Cyprus.

H.4 Oil and gas platform electrification

There is currently no oil and gas platform electrification in Cyprus. The AFID Law, which provides for the development of alternative fuels infrastructure, does not specifically address oil and gas platforms. The AFID Law does empower the Cyprus Ports Authority ("CPA") to assess the need for shore-side electricity supply and/or refuelling points for LNG in ports and to make recommendations for inclusion of related objectives in the NPF, so that an appropriate number of refuelling points for LNG, as well as shore-side electricity supply installations, are deployed by 31 December 2025. According to the NPF, the matter is currently under assessment by CPA.

H.5 Industrial hubs

There is no specific legislative framework for the establishment and operation of business clusters or industrial hubs. According to the National Policy Statement for the Enhancement of the Entrepreneurial Ecosystem in Cyprus issued in 2015,[150] a plan was to be prepared to promote the creation of business clusters that would facilitate strategic cooperations and economies of scale, however, to date this has not materialised.

H.6 Smart cities

A national framework strategy for the development of smart cities is under preparation by the Deputy Ministry of Research, Innovation and Digital Policy.[151] This will include existing local initiatives, new initiatives and an appropriate implementation plan.

I. Environmental, social and governance (ESG)

Sustainable finance and investment is a key consideration in policymaking and strategic planning by the Cyprus Securities and Exchange Commission ("CySEC").[152] CySEC's objectives include promoting the understanding of market participants regarding ESG obligations (eg reporting and disclosure) and protecting the interests of investors (eg from misrepresentations and greenwashing). There is no reported information on how ESG issues may affect investment in the energy sector.

Endnotes

1. Set up under the Development of Electricity Law, Cap 171, as amended.
2. CERA Regulatory Decision 04/2014 on the Functional Unbundling of the EAC, RAA. 372/2014, CERA Regulatory Decision 03/2014 on the Separation of Accounts of the EAC, RAA.371/2014, and CERA Regulatory Decision 02/2014 on Regulatory Accounting Guidance on the Preparation of Separated Accounts by the EAC, RAA.370/2014, each as amended from time to time.
3. Created by the Regulation of the Electricity Market Law of 2003, now replaced by the EML of 2021.
4. Directive (EU) 2019/944.
5. Sections 73, 74, 76 and 77 EML and CERA Regulatory Decision 03/2022 on the Establishment of General Principles for the Preparation of a Ten-year Programme for the Development of the Transmission System, RAA. 107/2022, replacing a 2020 decision on the same subject-matter.
6. Sections 85 and 93 EML.
7. Section 78 EML.
8. TSO Annual Reports for the years 2009 and 2020, included in the respective CERA annual reports.
9. CERA Regulatory Decision 01/2017 on the Implementation of a Binding Schedule for the Full Commercial Establishment of the New Electricity Market Model, RAA. 34/2017.
10. Created by the Setting up and Operation of the Cyprus Energy Regulatory Authority Law of 2021.
11. Section 4 EML.
12. Sections 26 and 27 EML.
13. CERA Regulatory Decision 02/2021 on the Regulatory Framework for the Grant of General Licence, RAA.523/2021.
14. Section 27(4) EML.
15. Section 5 EML.
16. Issued in January 2020 pursuant to the Governance Regulation.
17. Section 25(3) EML.
18. Section 22 EML.
19. Section 113 EML.
20. Section 94 EML.
21. Section 34 EML.
22. Section 111 EML.
23. Sections 44, 49 and 82 EML.
24. Section 71 EML.
25. Section 97 EML.
26. The Regulation of the Electricity Market (Procedures for Electricity Tariffs Setting Regulations) of 2004, RAA.472/2004, which were issued pursuant to legislation that has now been repealed and replaced by the EML but which remain in force until replaced by CERA
27. Section 97 EML.
28. Sections 49 and 139 EML.
29. CERA Regulatory Decision 02/2021 on the Regulatory Framework for the Grant of General Licence, RAA.523/2021
30. CERA Regulatory Decision 04/2017 on the Implementation of a Transitory Regulation in the Cyprus Electricity Market prior to the Full Implementation of the New Electricity Market Model, RAA.223/2017.
31. CTSO annual report 2020.
32. CERA Regulation 01/2015 on the new electricity market arrangements in Cyprus, RAA.164/2015.
33. Section 22 EML.
34. Sections 23, 40, 45, 55, 64 and 65 EML.
35. Article 66(4) of the recast Electricity Directive (EU) 2019/944
36. Sections 23, 112 and 114 EML.
37. Section 23(4) EML.
38. Regulatory decisions on prices are issued in accordance with the procedure established by the Regulation of the Electricity Market (Charging Procedures for Electricity Prices) Regulations of 2004, RAA.472/2004. CERA has recently issued CERA Regulatory Decision 01/2022 on the Establishment of General Principle and Guidelines on the Charges for Connection to the Transportation and Distribution Systems, RAA.105/2022.
39. Section 98 EML.

40. Section 99 EML.
41. CERA Regulatory Decision 02/2015, Regulatory Practice Statement and Electricity Tariffs Methodology, RAA.208/2015.
42. CEAR Decision 1565/2016.
43. CERA Regulatory Decision RAA.177/2006, as amended from time to time.
44. CERA Regulatory Decision 01/2021, Regulatory Practice Statement and Electricity Tariffs Methodology, RAA.359/2021, as amended by CERA Regulatory Decision 05/2022, RAA.183/2022.
45. Section 29 EML.
46. Regulation of the Electricity Market (Issue of Licences) Regulations of 2004, No.358/2004, which were issued pursuant to legislation that has now been repealed and replaced by the EML but which remain in force until replaced by CERA.
47. Regulation of the Electricity Market (Licence Fees) Regulations of 2004, No.467/2004; figures in Euro (€) as per Regulation of the Electricity Market (Licence Fees) Regulations of 2007, No.365/2007.
48. Section 30 EML.
49. Section 28 EML.
50. Section 33 EML.
51. Section 31 EML.
52. Section 95 EML and CERA Regulatory Decision 02/2022 on the Provision of Guidance on the Establishment of a Procedure for Connection to the Transmission System and to the Distribution System, RAA.106/2022.
53. Section 49 EML.
54. CERA Regulatory Decision 02/2019 on the Preparation of an In-Depth Techno-Economic Study for Redesigning of the Transmission System and Distribution System 2021-2030, RAA. 204/2019 and CERA annual report of 2018.
55. CERA Regulatory Decision 03/2019 on the Establishment of the Key Principles of the Regulatory Framework for Operating Electricity Storage Facilities In-Front-Of-The-Meter in the Wholesale Electricity Market, RAA.224/2019, and Transmission and Distribution Rules, most recently amended in December 2021.
56. Sections 111 and 112 EML.
57. CERA Regulatory Decision 01/2010 on the Imposition of Public Service Obligations, RAA.283/2010, as amended from time to time, most recently by CERA Regulatory Decision 03/2016, RAA.340/2016.
58. CERA Regulatory Decision 02/2018 on the Implementation of a binding timetable for mass installation and operation by the DSO of Advanced Metering Infrastructure, RAA. 259/2018.
59. Section 125 EML.
60. Directive 2014/94/EU.
61. Section 13 of the AFID Law.
62. Sections 15, 16 and 51 of the AFID Law.
63. CERA Decision 228/2020 on charging stations for electric vehicles.
64. Scheme information available at Recharging of Electric Vehicles scheme (eac.com.cy).
65. Regulation (EU) no. 347/2013 on guidelines for trans-European energy infrastructure.
66. CERA annual report 2020.
67. Information available at Euroafrica-interconnector.com.
68. Under the law on the Natural Gas Public Company of 2022 (the "DEFA Law"), DEFA is created as a public law body the object of which is supplying natural gas in Cyprus, including transporting and distributing natural gas and developing, operating and managing all related infrastructure. DEFA as a public law body will become the holder of the CERA licences that have been issued to DEFA Limited. The DEFA Law was published in July 2022 but will only come into force by decision of the Council of Ministers which is still pending.
69. Council of Ministers decision no. 87.649 dated 5 June 2019, pursuant to sections 16(1) and 21 GML.
70. Directive (EU) 2019/692 amending Directive 2009/73/EC concerning common rules for the internal market in natural gas.
71. Section 7 GML.
72. Rules on the Supply of Natural Gas, version 1/2020, dated March 2020
73. Sections 16, 21 and 22 GML.
74. Section 18 GML.
75. Section 24 GML.
76. Section 29 GML.
77. CERA Regulatory Decision 4/2020 on the Separation of Accounts for Natural Gas Undertakings, RAA.344/2020, and CERA Regulatory Decision 5/2020 on Regulatory Accounting Guidance on the Preparation of Separated Accounts for Natural Gas Companies, RAA.345/2020.
78. Section 44 GML.
79. CERA decision no. 1/2019, RAA 203/2019.
80. Section 44(2) GML. and CoM Decision.
81. CERA annual report 2020.
82. Section 30 GML.
83. Sections 16 and 22 GML.
84. Section 32 GML.
85. Section 32 GML.
86. Sections 16 and 30 GML.
87. Section 31 GML.
88. Section 30 GML.
89. Section 40 GML.
90. Regulation of the Gas Market (Issue of Licences) Regulations of 2006, No.298/2006.
91. Regulation of the Gas Market (License Fees) Regulations of 2006, No.299/2006; figures in Euro (€) as per Regulation of the Gas Market (License Fees) Regulations of 2007, No.366/2007.
92. Section 10 GML.
93. Section 11 GML.
94. Section 14(1) GML.

95. Section 14(2) GML.
96. Section 44 GML.
97. Section 39 GML.
98. Sections 6(1) and 40 GML.
99. Ratified by law 3(III)/2019.
100. Ratified by law 5(III)/2020.
101. Regulation (EU) no. 347/2013 on guidelines for trans-European energy infrastructure.
102. Section 45 GML.
103. Section 44A GML.
104. Section 94 EML.
105. CERA Regulatory Decision 04/2017 on the Implementation of a Transitory Regulation in the Cyprus Electricity Market prior to the Full Implementation of the New Electricity Market Model, RAA.223/2017.
106. CTSO annual report 2020.
107. CTSO annual report 2020.
108. CERA Regulation 01/2015 on the new electricity market arrangements in Cyprus, RAA.164/2015.
109. Cyprus acceded to the Euratom on 1 May 2008, on which date the application of IAEA safeguards for Cyprus under the bilateral IAEA – Cyprus safeguards agreement (reproduced in INFCIRC/189) in force since 26 January 1973 was suspended and the agreement of 5 April 1973 between the non-nuclear-weapon States of Euratom, Euratom and the Agency (reproduced in INFCIRC/193) entered into force for Cyprus.
110. Council Directive 2009/71/Euratom establishing a Community framework for the nuclear safety of nuclear installations, as amended by Council Directive 2014/87/Euratom.
111. Council Directive 2013/59/Euratom laying down basic safety standards for protection against the dangers arising from exposure to ionising radiation; Council Directive 2006/117/Euratom on the supervision and control of shipments of radioactive waste and spent fuel; and Council Directive 2011/70/Euratom establishing a Community framework for the responsible and safe management of spent fuel and radioactive waste.
112. General Safety Requirements No. GSR Part 1 (Rev. 1) "Governmental, Legal and Regulatory Framework for Safety" (Vienna, 2016) and General Safety Requirements No. GSR Part 3 "Radiation Protection and Safety of Radiation Sources: International Basic Safety Standards" (Vienna, 2014).
113. Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons.
114. Directive 2013/30/EU on safety of offshore oil and gas operations.
115. Directive (EU) 2018/2001.
116. Section 5 RES Law.
117. Section 20 of the law on the Specifications, Sustainability Criteria and Reduction of Emissions from Fuels of 2022.
118. Section 6 RES Law.
119. Operates pursuant to the Law on the Operation of the Renewable Energy Sources and Energy Conservation Fund of 2022, which provides for funds held by a pre-existing fund with similar aims to be transferred to the RES Fund.
120. Regulation on the Promotion and Encouragement of the use of RES (Fixing of the Rate of the Consumption Levy) of 2019, RAA. 417/2019.
121. Section 18 RES Law.
122. Section 38 RES Law.
123. Section 37 RES Law.
124. Information on currently open support schemes is available on the website of the Energy Service of the Ministry of Energy at energy.gov.cy.
125. Information on currently open support schemes promoted by the RES Fund is available on the website of the RES Fund at RES Fund schemes.
126. Decree on the Blending Percentage for Conventional Transport Fuel with Biofuel of 2020, RAA.11/2020.
127. Section 26 of the Fuel Specifications Law.
128. Decree on the Blending Percentage for Conventional Transport Fuel with Biofuel of 2020, RAA.11/2020.
129. Section 17(2) Fuel Specifications Law.
130. Section 21 Fuel Specifications Law.
131. Information available on the website of the Energy Service of the Ministry of Energy at energy.gov.cy.
132. Activity Report of the RES Fund for 2020.
133. 2020 NECP.
134. Section 3 ETS Law.
135. Sections 6 and 12 ETS Law.
136. Sections 11, 15 and 28 of the ETS Law.
137. Sections 22 and 24 ETS Law.
138. Section 21 ETS Law.
139. Section 40 ETS Law.
140. Part 1 of Annex 1 of the law on Motor Vehicles and Road Traffic of 1972 as amended,
141. Fluorinated Greenhouse Gases (Control, Prevention and Reduction) Law of 2016 as amended, which supplements, inter alia, Regulation (EU) No 517/2014.
142. Section 34 EML.
143. Regulation (EU) 2019/943.
144. Section 34 EML and Chapter IV of Regulation (EU) 2019/943.
145. Sections 5 and 21 AFID Law.
146. Section 6 CSS Law.
147. Sections 7 to 10 CCS Law.
148. Section 12 CCS Law.
149. Sections 22 and 23 CCS Law.
150. See National Policy Statement.
151. See DMRID Strategic Plan 2022-2024.
152. See Sustainable Finance (cysec.gov.cy).

Energy law in Czech Republic

Recent developments in the Czech energy market

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Mergers and acquisitions

Several major transactions were completed in 2019 and 2020. The most notable, the euro-wide merger of RWE and E.ON – historically the largest energy transaction in Europe – had a major impact on the Czech market, as innogy, Česká republika a.s. (formerly a subsidiary of RWE) had been the largest Czech supplier of natural gas with over 1.7 million customers in the Czech Republic as well as a major player in gas distribution and storage. To complete the transaction between E.ON and RWE, an agreement to divide innogy's Czech activities was concluded with the European Commission.

In October 2019, the Australian investment company Macquarie Infrastructure and Real As-sets (who had previously acquired a 31% share in EP Infrastructure, a.s., an energy company engaged in the storage and transport of natural gas and electricity distribution) acquired a 100% share of innogy Grid Holding, a.s. and rebranded the company to Czech Grid Holding, a.s. Czech Grid Holding, a.s. is the 100% owner of GasNet s.r.o., which supplies gas to 2.3 million customers in the Czech Republic and has a total network length of about 65,000km.

In July 2020, all of innogy's gas storage facilities were transferred back to the RWE group. In-nogy Gas Storage, s.r.o., the largest operator of underground gas storage facilities in the Czech Republic, changed its name to RWE Gas Storage CZ, s.r.o. The company operates six gas storage facilities in the Czech Republic with a total storage capacity of 28.7TWh.

The retail side of the business represented by innogy Česká republika, a.s., innogy Energie s.r.o., innogy Zákaznické služby s.r.o. and innogy Energo s.r.o. was sold to the Hungarian state energy company MVM Group and continues to operate in the Czech Republic under the innogy brand. The transaction was closed in March 2021.

In October 2020, Europe Easy Energy, a.s., a member of the Bohemia Energy Group, ac-quired Energie ČS. Energie ČS was owned by Česká Spořitelna bank and will keep its brand. With more than 1.2 million customers and annual sales of over CZK21 billion (about €0.83 million), the Bohemia Energy Group is the largest group of alternative energy suppliers in the Czech Republic.

In March 2021, the ČEZ group sold its Romanian assets and funds to Macquarie Infrastruc-ture and Real Assets. The sale includes a total of seven Romanian companies.

Significant new installations and projects

Continuing the trend of the previous few years, 2018 and 2019 saw the maintenance of cur-rent energy facilities and the opening of new ones. ČEZ's long-term strategy is to achieve carbon-neutral electricity production by 2050. The company is also planning to shut down more than half of its coal power plant capacity by 2035, and to only continue with new and modernised coal power plants. ČEZ Group wants to reduce its emissions by 55% by 2030 compared to 2019. To achieve this, ČEZ plans to generate only 25% of all its electricity pro-duction from coal in 2025, and only 12.5% in 2030. At the same time, ČEZ plans to increase its renewable energy source ("RES") capacities to 1.5GW of installed capacity in 2025 and a total of 6GW in 2030.

Nuclear power plants will remain part of the carbon-neutral and stable portfolio. In 2020, ČEZ invested around €35 million to modernise and increase the security and performance of the Temelín nuclear power plant as its licence had to be renewed. The Temelín nuclear power plant has two reactors, each with an installed capacity of 1,125MW. ČEZ is also planning to construct a new nuclear reactor at the Dukovany power plant (see below).

Following the worldwide boom in battery energy storage, ČEPS, a.s., an electricity transmis-sion system operator ("TSO"), has taken certain measures to support the development of energy storage, as it has decided to involve batteries in the market of support services. Fur-thermore, an amendment to the Energy Act, which should legislate battery energy storage, is currently being discussed. To date, four large-capacity battery systems with a total output of about 10MW and a capacity of over 8MWh have been built in the Czech Republic. Dozens of other large-capacity battery systems with an output of over 1MW are expected to be built in the Czech Republic in the coming years.

Significant trends in the energy sector

Nuclear power has seen a significant increase in production in recent years. This trend is acknowledged by the Czech Government decision to allocate CZK1.7 billion (about €67 million) for the construction of a new nuclear waste storage facility. Additionally, the Czech Government and ČEZ plan to expand the Dukovany power plant with the construction of a new nuclear reactor. The project is in the process of preparing a tender, which should start in 2022. The contractor is expected to be selected in 2024 and construction of the new reactor should begin in 2029. South Korea's KHNP, France's EDF and the US-Canadian company Westing-house are among the potential suppliers. The Russian company Rosatom was excluded from the tender due to political reasons. The expected cost of the whole project is around €6 billion.

Battery energy storage is another major area of interest in the Czech Republic (see above, Significant new installations and projects). The Czech Energy Regulatory Office ("ERO") has expressed that it is in favour of battery energy storage; however, ERO has also highlighted the need for further regulation and consideration of the costs of this new technology. Prepara-tory works on the amendment to the Energy Act addressing battery energy storage is already underway.

In 2021, the Czech Republic started drawing funds from the Modernisation Fund created un-der the EU ETS Directive. The aim of the Modernisation Fund is to support investments in new RES installations and to improve energy efficiency between 2021 and 2030. The result should speed up the transition to a low-carbon economy. The total funds available are ex-pected to be at least CZK150 billion (about €5.9 billion). The Czech Republic supplemented the resources of the Modernisation Fund with income from emission allowances, which were previously allocated free of charge. The total amount of available funds therefore depends on the development of emission allowance prices. The subsidy from the Modernisation Fund are available for projects within the following areas:

- modernisation of heat supply systems;
- new RES installations;
- improvements of energy efficiency and reduction of greenhouse gas (GHG) emis-sions in the industrial sector;
- modernisation of public transport and transport in the business sector;
- energy efficiency improvements in public buildings and infrastructure;
- modernisation of public lighting systems; and
- communal energetics.

Law enforcement activities by the competition authorities

In November 2017, the ERO and the Czech Office for the Protection of Competition agreed on a memorandum that establishes new cooperation in general, as well as in the preparation of legislation, sharing of information and experience in actual cases.

In December 2020, the mining companies Severočeské doly a.s. and Severní energetická a.s. were fined more than CZK25 million (about €1 million) by the Czech Office for the Protection of Competition for concluding prohibited agreements banning the export of brown coal from 2004 to 2013.

In 2017, the Czech Republic lost an arbitration between the state and Natland Group for potential violation of an agreement for the promotion and reciprocal protection of investments through the implementation of a solar tax. The Czech Republic appealed the decision, but the appeal was rejected in 2020. The solar tax was implemented as a result of the boom in photovoltaic ("PV") power plant construction in 2010. The Czech Republic vs. Natland case is the first arbitration over the introduction of the solar tax won by investors.

The ERO has commenced one of the biggest investigations of energy supply contracts for unfair practices with consumers. The investigation concerns collection agencies that are sending texts or e-mails to consumers (following their withdrawal from energy supply con-tracts) threatening them with a writ of execution on a money judgment within 48 hours, which is an unrealistic procedure. The ERO and the Czech Trade Inspection Authority ("CTIA") are also advising consumers how to respond. The investigation has already led to the imposition of the historically highest fine for anti-consumer behaviour in energy sector, when, in 2019, the ERO imposed a fine in the amount of CZK4 million (about €160,000) on STABIL s.r.o.

Other significant industry developments

Paskov and ČSM coal mines

The Paskov coal mine closed on 31 March 2017. Its owner, OKD, a.s. ("OKD"), obtained consent for the liquidation plan contained in an environmental impact assessment of the mine. OKD and the state-owned company Prisko, OKD's new sole shareholder, started liquidation in August 2019. OKD is also planning to close its last coal mine ČSM in 2022.

Turów mine dispute

The Czech Republic was in dispute with Poland before the Court of Justice of the EU regard-ing the expansion of the Turów coal mine, which is in Poland near the Czech border. Czech authorities claimed that the expansion of the mine was causing a loss and disproportionate pollution of the groundwater on the Czech side of the border. In 2021, the European Court of Justice issued an order to close the Turów mine. Initially, Poland ignored this order (which resulted in a fine imposed by the European Court of Justice), however, the issue has finally been resolved via settlement between the Czech Republic and Poland in February 2022.

Imminent significant changes to the legal framework under discussion

Amendment to the Act on Supported Energy Sources

In October 2021, an amendment to the Act on Supported Energy Sources1 introduced signifi-cant changes which address two key areas, ie control of the proportionality of support for renewable energy production (overcompensation) and the new renewable energy support system ("RES system").

The purpose of overcompensation controls is to determine whether the operational support received by renewable energy producers is disproportionate. The controls are taking effect 10 years after the respective RES was commissioned and will assess the profitability of invest-ments in RES using an internal rate of return ("IRR"). The controls are performed by sector inquiries examining the support for producers in a particular renewable energy sector (eg PV plants). If the inquiries reveal an overcompensation of a certain sector, the ERO may reduce future support provided to the given sector in order to achieve a reasonable amount of IRR. If a producer does not agree to a reduction of the support as a result of a sector inquiry, it may request an individual review of the IRR. Overcompensation can also occur if a project received other forms of subsidies in addition to operational support.

The second area where significant changes have been made is the introduction of the new RES system. Support for selected RES will be competed for in auctions for the first time. The aim of the auctions is to minimise the costs of supporting energy from RES and to achieve maximum production efficiency. The auctions will cover medium and large plants with an installed capacity of 1MW and over. Small plants up to 1MW will continue to be supported in the form of green bonuses.

Endnotes

1. Act No. 165/2012 Coll., on Supported Energy Sources (*zákon o podporovaných zdrojích energie a o změně některých zákonů*).

Overview of the legal and regulatory framework in Czech Republic

A. Electricity

A.1 Industry structure

Nature of the market

The Czech electricity market has been fully liberalised since 2006, when the electricity transmission system operator ("TSO") and the distribution system operators ("DSOs") completed the process of unbundling and restructuring. The full ownership unbundling ("FOU") model is applied for electricity production. Electricity distribution is provided by different companies and many new entrants join the electricity market every year. The Czech Republic also exports electricity and over 25% of total electricity generated in the country is exported.

Key market players

The key market players in the electricity sector are:

- electricity producers;
- the TSO;
- DSOs;
- the market operator; and
- electricity traders.

The ČEZ group ("CEZ") is the main electricity producer and is considered the main market player. CEZ provided about 67.577% of the electricity used in the Czech Republic in Q1 2021. The Czech Republic is the majority shareholder of CEZ and owns about 70% (through the Ministry of Finance). As of 1 June 2021, CEZ operates two nuclear power plants, 35 hydropower plants, including three pumped storage plants, two wind power plants, one biogas power plant, one steam-gas power plant, 12 photovoltaic ("PV") power plants and 11 coal-fired plants in the Czech Republic.[1]

The state-owned TSO, ČEPS, a.s. ("CEPS") is the only holder of an electricity transmission licence in the Czech Republic. The role of CEPS involves ensuring electricity transmission, procuring ancillary services, ensuring the provision of system services, balance of electricity generation and consumption, and maintaining and developing the transmission system equipment. CEPS is also responsible for the interconnected operation of the Czech power system with those of neighbouring countries and organises auctions for the allocation of available transfer capacity on interconnectors through the intraday electricity market under the Union for the Co-ordination of Transmission of Electricity ("UCTE") rules.

ČEZ Distribuce a.s., E.ON Distribuce a.s. and PRE Distribuce, a.s. are the most significant DSOs in the Czech Republic. ČEZ Distribuce, a.s. (unbundled from the CEZ electricity generating companies) is the biggest DSO in the Czech Republic and is responsible for electricity distribution in North Bohemia, North Moravia and Silesia. E.ON Distribuce, a.s. is the main regional DSO in South Bohemia and South Moravia. PRE Distribuce, a.s. is a separate regional DSO that supplies electricity to the Prague metropolitan area. The only licensed market operator is OTE, a.s. ("OTE").

Electricity can be traded on markets organised by the European Energy Exchange AG ("EEX") and OTE. See section C.1 below for more information on electricity trading.

Regulatory authorities

Responsibility for public administration in the energy sector is shared by the Czech Government, the Ministry of Industry and Trade *(Ministerstvo průmyslu a obchodu)* ("MIT"), the Energy Regulatory Office *(Energetický regulační úřad)* ("ERO") and the State Energy Inspection Board *(Státní energetická inspekce)*.

The ERO was set up on 1 January 2001 as the administrative authority for regulation in the energy sector. The ERO is responsible for:

- price control;
- support for the use of renewable and secondary energy sources, and combined heat and power generation;
- protection of customers and customers' interests;
- protection of licence holders' vested interests;
- enquiries into conditions for competition;
- cooperation with the Office for the Protection of Competition *(Úřad pro ochranu hospodářské soutěže)* and with the Czech National Bank *(Česká národní banka)*;
- support for competition in the energy industry; and
- overseeing of markets in the energy industry.

Since 1 August 2017, the ERO has been led by the Board of the ERO ("Board"). The Board consists of five members, all of whom are appointed by the Czech Government.

Legal framework

The main legal framework for business activities, performance of public administration and regulation in all energy sectors is provided by the Energy Act[2] and its implementing regulations. The most important regulation is the Decree on Electricity Market Rules[3] which:

- determines the general terms and conditions for distribution and TSOs;
- stipulates that the load on transmission operators should be within its capacity;

- outlines procedures and conditions for transferring and taking responsibility for deviations;
- enables switching between electricity suppliers;
- sets out the composition of price and billing prices between market players; and
- sets out other market rules.

Implementation of EU electricity directives

From the Czech perspective, the EE Directive (including its 2018 amendment 2018/2002/EU) has been transposed into Czech legislation, primarily through the Energy Act and the Energy Management Act.[4]

A.2 Third party access regime

Under the Energy Act, all electricity market participants have access to the transmission and distribution systems subject to the fulfilment of certain general, technical and financial conditions, which apply depending on whether or not the intended access is to be physical.

A.3 Market design

The Czech electricity market is now fully liberalised (see section A.1).

A.4 Tariff regulation

Under the Energy Act and the Price Electricity Regulation[5] ("ERO Regulation"), the ERO must set regulated prices related to electricity supply annually, with tariffs approved ex-ante. A description of how the principles are set, the methods for determining the parameters of regulation, including deadlines for notifying those parameters to the respective licence holders in the energy sector, is set out in the methodology for electricity, gas and market operator activity. In June 2020, the ERO issued a new methodology for the period 2021 to 2025,[6] with effect from 1 January 2020 ("Methodology").

The Methodology aims to:

- determine a reasonable level of profit for companies during the subsequent five-year regulatory period;
- ensure an adequate quality of services provided to customers, with effective spending of costs to support future investments;
- provide for the resources required for network renovation; and
- continue to improve efficiencies from which customers will also benefit.

The ERO Regulation applies to all entities doing business in the energy sector. In the context of the Methodology, such entities include suppliers that hold licences for transmission and distribution of electricity, licences for market operator activities and licences for electricity trading. Prices are regulated to ensure suppliers do not have an uncontrolled ability to set their own price levels.

The final price of electricity supply for all categories of final customers has five basic components. The first component is a non-regulated price (ie electrical energy itself, which is priced based on market principles and in line with the various electricity suppliers' business strategies). The other four components are regulated activities, ie transport over the transmission and distribution systems, provision of system services, electricity market operator activities in the area of imbalance clearing, and contributions to support electricity from renewable sources.

A.5 Market entry

Licensing regime

All activities within the Czech Republic's electricity sector require a licence granted by the ERO. All applicants must meet a number of general, professional, technical and financial requirements. Details of the individual requirements for obtaining an electricity licence are provided by the Energy Act and the Decree on Energy Sectors Business Licensing. With some exceptions, self-producers with maximum installed capacity of 10kW are not subject to the licensing requirement.

The procedure for obtaining an electricity licence usually takes around 30 days (in more complex cases the deadline may be extended). Licences for electricity generation are granted for a maximum of 25 years. Licences for transmission, distribution, storage and operation are granted for an indefinite period.

Foreign applicants wishing to apply for an electricity licence must have a corporate presence in the Czech Republic in order to obtain/keep a licence. A foreign company can either set up a Czech subsidiary that can apply for the electricity licence or maintain a branch in the Czech Republic under the Czech Commercial Code. The branch must be registered in the Czech Commercial Register and have a registered branch head. There is no requirement for the branch head to be a citizen or a resident of the Czech Republic. A branch has no legal personality under Czech law and therefore the parent company must apply for an electricity licence through the branch. The parent company will then be the licence holder. A company licensed in another EU Member State can request the ERO to recognise its licence from that Member State.

Market trading

Electricity traders must obtain a trading licence from the ERO. Applicants for electricity trading licences must meet a number of general, professional, technical and financial requirements, the details of which are set out under the Energy Act and the Decree on Energy Sector Business Licensing. Traders can be either natural persons or legal entities. Licences for electricity trading are granted for five years and can be extended for a further five years if specific conditions are met. If a foreign legal entity wishes to trade and is already licensed in another EU Member State, that entity can request the ERO for recognition of its licence from that Member State. If the licence is recognised by the ERO, the entity need not obtain another trading licence from the ERO.

Electricity traders do not need physical access to trade electricity and are not required to have grid access to the transmission or distribution system. Traders must, however, enter into an electricity transmission or distribution agreement with the TSO or relevant DSO. Under these agreements, traders can use the grid to transmit or distribute electricity to or from their customers (see section C.1).

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Under the Energy Act, electricity transmission, distribution and generation ancillary services are established and operated in the public interest. In the public interest, and if urgent, the distribution licence holder is obliged to ensure the distribution of electricity beyond the requirements of its licence if requested by the ERO.

Smart metering

The National Action Plan for Smart Grid ("NAPSG") sets out a plan for gradual implementation of smart metering. According to the NAPSG outlook, by the end of 2024, 30% of consumption sites in low-voltage networks in the Czech Republic should be installed with smart electricity meters. By the end of 2029, all consumption sites should be installed with smart electricity meters.

With effect from 1 January 2021, the Czech Republic adopted the Decree on Electricity Metering[7] ("DEM"), which regulates a smart metering system in accordance with the requirements of EU legislation. The DEM is a comprehensive legal framework of electricity metering and, among other things, lays down minimum functional and technical requirements for smart meters. The DEM further regulates a compulsory installation of smart metering equipment in consumption sites with consumption greater than 6MWh, which will come into effect on 1 July 2024.

Electric vehicles

In May 2020, the Czech Republic reviewed its plan for implementing measures designed to motivate a significant increase in the percentage of electric vehicles ("EVs") in transport. New measures were introduced in the Memorandum on the Future of the Automotive Industry in the Czech Republic and the Action Plan on the Future of the Automotive Industry in the Czech Republic. These measures consist of improvements in transport infrastructure and investments in research, development and innovation in the electromobility field. CEZ has also taken some steps in the development of rapid-charging station infrastructure, which is partly financed by subventions from the European Connecting Europe Facility ("CEF") programme to reach a mandatory 14% share of renewable energy sources ("RES") in transport.

A.7 Cross-border interconnectors

The Czech Republic is situated in the heart of Europe. Due to its location, it is a transit country that provides a transit system for its five neighbouring transmission systems, which include SEPS (Slovakia), PSE (Poland), APG (Austria), TENNET and 50Hertz (Germany). The Czech Republic has five cross-border interconnectors with Slovakia, four with Poland, four with Austria and four with Germany.

The export, import and transmission of electricity is limited by the capacity of cross-border interconnectors. Demand for capacity at the transmission interconnectors between Austria and the Czech Republic, for example, is usually higher than the available capacity.

B. Oil and gas

B.1 Industry structure

Nature of the market

The Czech Republic is highly dependent on imports of both oil and gas as the country does not have large deposits of these resources. The gas supply market has been fully liberalised since 1 January 2007, giving end consumers the right to switch to a different supplier without paying fees. Despite being fully liberalised, there was no real competition in the gas market until 2010, when the ERO equalised the conditions for gas storage to all suppliers, thereby enabling small independent suppliers to enter the market.

Key market players

The main oil market players are:

- three oil generators;
- MERO a.s., ie the owner and operator of the central storage system and the Czech section of the Družba crude oil pipeline and the IKL crude oil pipeline; and
- Unipetrol RPA, s.r.o, ie the operator of the Czech oil refineries.

The main gas market players are:

- 13 gas generators;
- one TSO, ie NET4GAS, s.r.o. ("NET4GAS");
- around 70 DSOs;
- four storage system operators;
- one market operator, ie OTE; and
- 230 gas traders.

The main gas generator is MND, a.s., which provided less than 2% of the gas used in the Czech Republic in 2018. The Czech distribution networks are operated by GasNet, s.r.o. (in the central and northern parts of the country), E.ON Distribuce, a.s. (in the south) and Pražská plynárenská, a.s. (in Prague). The key storage system operators are RWE Gas Storage CZ, s.r.o. (formerly innogy Gas Storage, s.r.o.; to 28 June 2020) and MND Gas Storage, a.s..

Regulatory authorities

The regulatory authority for oil is the ERO (see section A.1).

Legal framework

The main legal framework is the same as that of the electricity sector (see section A.1).

There are differences, however, between the implementing regulations. The most important implementing regulation for gas is the Decree on Gas Market Rules,[8] which sets out:

- rules for access to the transmission system, distribution systems and gas storage facilities, including the scope of the information to be published to enable access to the transmission system, distribution systems and gas storage facilities, and methods of congestion management in the gas system;
- procedures and conditions for transferring and assuming responsibilities for imbalances;
- the scope of, and time limits for, exchanging information for the evaluation of imbalances and billing of gas supplies and

other services, and procedures for evaluating, clearing and balancing imbalances;

- storage system operators' procedure for selling gas left in gas storage facilities on discharge of gas storage agreements; and
- procedures and rules for the organisation of spot markets and methods of settlement.

Implementation of EU gas directives

The Czech Republic has fully transposed the Third Gas Directive into national legislation through the Energy Act.

B.2 Third party access regime to gas transportation networks

Under the Energy Act, all gas market participants have access to the transportation and distribution systems and have the right to the free accumulation of gas.

Under the Act, TSOs and DSOs must connect any market participant that applies if it meets the connection conditions (particularly the technical conditions) to the system, except when there is a capacity shortage on the network. System operators must provide equal conditions for all gas market participants. The price to be paid for access by third parties to the system is determined by the ERO. The price for gas transportation and distribution is also regulated by the ERO.

B.3 LNG terminals and storage facilities

The main legislative framework for gas storage is set by the Energy Act and further developed under secondary legislation through the Decree on Gas Market Rules and the Decree on Gas Supply Security Standard.[9]

There are no LNG terminals in the Czech Republic; however, gas storage capacity is among the highest in Europe with regards to local consumption. There are currently six gas storage facilities (of cumulative capacity of 2.7 billion cubic metres ("bcm") operated by RWE Gas Storage CZ, s.r.o. two gas storage facilities operated by MND Gas Storage, a.s., one operated by SPP Storage, s.r.o., and one operated by Moravia Gas Storage, a.s.. Overall storage capacity is in excess of 3.5bcm.

Under the Decree on Gas Market Rules, free storage capacity must be offered in electronic auctions. The starting price is based on spot market prices. Storage companies must announce the auction in advance together with other essential information, such as offered capacity and storage periods.

Under the Decree on Gas Supply Security Standard, storage companies must reserve a certain capacity for protected customers.

B.4 Tariff regulation

Under the Energy Act and the Decree on Gas Price Regulation,[10] the ERO sets the regulated prices related to gas supply every year, with tariffs to be approved ex-ante. A description of how the principles are set, the methods for determining the parameters of regulation, including deadlines for notifying those parameters to the respective licence holders in the energy sector, are set out in the methodology for electricity, gas and for market operator activity. In June 2020, the ERO issued a new methodology for 2021 to 2025,[11] which came into effect from 1 January 2020 ("Gas Methodology").

The Gas Methodology aims to:

- determine a reasonable level of profit for companies during the subsequent five-year regulatory period;
- ensure an adequate quality of the services provided to customers, with effective spending of costs, to support future investments;
- provide for the resources required for network renovation; and
- continue to improve efficiencies, from which customers also will benefit.

The ERO Regulation applies to entities doing business in the energy sector. In the context of the Gas Methodology, such entities are suppliers that hold licences for the transmission and distribution of gas, licences for market operator activities and licences for gas trading. Prices are regulated to ensure suppliers do not have an uncontrolled ability to set their own price levels.

B.5 Market entry

Licensing regime

Gas trading in the Czech Republic is subject to licensing. Licences are granted by the ERO. Under the Energy Act, applicants must meet a number of general, professional, technical and financial requirements, the details of which are set out in the Energy Act and the Decree on Energy Sector Business Licensing. Therefore, all business activities in the gas sector (ie production, transportation, distribution, storage and trading) can only be carried out after a licence is obtained from the ERO.

Licences for gas generation are granted for a maximum of 25 years. Licences for transmission, distribution and storage are granted for an indefinite period. Licences for gas trading are granted for five years (see section C.2).

The Czech regulatory system is open to newcomers to the gas market and guarantees equal treatment for all interested parties that meet the licence conditions as set out in the Energy Act.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Under the Energy Act, gas transmission, distribution and generation ancillary services are established and operated in the public interest. In the public interest, and if urgent, the distribution licence holder is obliged to ensure the distribution of gas beyond the requirements of its licence as requested by the ERO.

Smart metering

As of June 2021, the Czech Republic has decided not to require compulsory installation of smart meters. However, voluntary installation of smart metering is permitted under the Energy Act.

B.7 Cross-border interconnectors

NET4GAS operates a transit pipeline with three international transfer stations; these are at Lanžhot, Brandov and Hora Sv. Kateřiny. There are also two international transfer stations, one at Cieszyn and one at Waidhaus, both of which are outside of Czech territory.

C. Energy trading

C.1 Electricity trading

The primary legislation dealing with electricity law in the Czech Republic is the Energy Act, which sets out the conditions for business activities together with the regulation and public administration of the energy sector. The Act on Supported Energy Sources[12] extensively covers the generation and trading of electricity generated from renewable sources.

Electricity trading is also regulated by secondary legislation. The Electricity Market Rules Decree[13] establishes the electricity market rules, rules for the determination of prices and the execution of certain other provisions of the Energy Act. Trading of electricity can be both physical and financial.

Electricity can be traded in the Czech Republic through:

- direct deliveries (over-the-counter ("OTC"));
- the short-term markets, ie the day-ahead market, the intraday market, the block market and the balancing market;
- the EEX T7 platform;
- the Czech-Moravian Commodity Exchange, Kladno *(Českomoravská komoditní burza Kladno)* ("CMCEK"); and
- brokers' platforms.

The rules for the organisation of the electricity market are set out in the Decree on Electricity Market Rules. To provide direct deliveries of electricity, electricity wholesale traders must conclude the following agreements:

- a sale and purchase agreement;
- an agreement on the settlement of imbalances with OTE;
- an electricity transmission or distribution agreement; and
- a short-term market access agreement.

To trade electricity in the Czech Republic, a trading licence holder must be registered with OTE within 30 days of the granting of the electricity trading licence under the Energy Act. An electricity trader becomes a registered market participant upon registration. Such participants are entitled to trade electricity on the balancing market. The Czech Republic is a participant of the CZ-SK-HU-RO Market Coupling project ("4M MC"). 4M MC integrates the day-ahead markets of the Czech Republic, Slovakia, Hungary and Romania. Electricity traders can now place bids for the purchase and/or sale of electricity for the whole 4M MC territory. Further connection of 4M MC with the Multi Regional Coupling (MRC) is planned to extend members to Austria, Germany and Poland to form DE-AT-PL-4M MC. DE-AT-PL-4M MC has successfully completed the first phase of joint regional testing (Full Integration Testing) at the end of February 2021. The following phase of the testing (Simulation Integration Testing) focusing on the testing of regional operational procedures started on 22 March 2021.

The Czech Republic is also a member of the Cross-border Intraday Coupling ("XBID") project, which aims to create a more transparent and efficient continuous business environment that will allow market participants to easily trade their intraday positions across EU markets and without need for an explicit allocation of transmission capacity. As of 19 November 2019, the XBID project went fully operational in the Czech Republic and during the first year of operation, 1,278,844 trades were concluded within the interconnected markets, with a total volume of 4,440GWh.

Following the migration of trading of Power Exchange Central Europe ("PXE") products into the EEX 17 platform, the electricity may also be traded on EEX T7 exclusively in the form of commodity futures with physical or financial settlement. PXE was established in January 2007 and in its first year of existence became the most significant energy exchange in the Central Eastern European region, offering trading for Czech, Slovak, Hungarian, Romanian and Polish power. As of January 2016, EEX became the majority shareholder of PXE. This regulated market is organised and controlled under the Act on Commodity Exchanges,[14] among others. Trading on EEX is only permitted to those that meet the conditions of participation in trading on EEX in accordance with legal regulations and PXE together with EEX rules and regulations.

Electricity can also be traded on the CMCEK. Under the CMCEK statute, persons authorised to trade on the CMCEK are members of the exchange or persons who are authorised to produce or manufacture goods that are the subject of exchange trades or authorised to trade in these goods. Members of the exchange can conclude exchange trades directly, ie by means of the relevant trader's assignee (ie broker), who is a natural person and a member of the exchange authorised to conclude trades in the trader's name. If trades are concluded by a non-member of the exchange (a person authorised for exchange trading), these trades must be concluded using one of the brokers with whom a respective proxy agreement is concluded, and remuneration for mediation must be agreed.

C.2 Gas trading

The main legislation dealing with gas trading is the Energy Act and the Decree on Gas Market Rules. Trading of gas can be both financial and physical. Physical trading is mostly realised from storage facilities. Under the Energy Act, gas trading requires a licence from the ERO. After obtaining a licence, licence holders can:

- buy and sell gas to other gas market participants;
- transport, distribute and store an agreed volume of gas; and
- access the transport system, distribution systems and storage facilities.

Gas can be traded on the same venues as electricity, except for the PEGAS CEGH Czech Market ("PEGAS"), which offers futures and spot market trading. PEGAS is organised by Powernext SAS in coordination with the Central European Gas Hub ("CEGH") and PXE.

The gas system is divided into balancing zones for the purpose of capacity booking and balancing. For each gas day, the gas quantity exiting from a balancing zone must equal the gas quantity entering that balancing zone. Balancing entities (ie eligible customers or gas traders) for whom the TSO evaluates, clears and settles imbalances on a contractual basis are responsible for matching the quantities that they take from the transportation system with the quantities that they supply into the gas system in one day.

D. Nuclear energy

The nuclear energy industry provides more than 34% of electricity consumption in the Czech Republic. There are two active nuclear energy power plants ("NPP"), one in Dukovany and one in Temelín, both of which are operated by CEZ.

Under the NAPNE and the State Energy Concept, which is a key strategic document for development in the energy sector, one of the main strategic objectives of the Czech Republic is to achieve an increase of nuclear energy to constitute about 50% of electricity produced domestically and to gradually replace coal as the core source of electricity. These objectives are to be achieved through the construction of two additional nuclear reactors at the existing nuclear plants (ie one at Temelín and one at Dukovany) and extending the life of all four existing nuclear reactors at Dukovany. As of June 2021, the timeline and financing of the construction of these projects is unknown (see section A.1).

The main piece of legislation dealing with nuclear energy is the Nuclear Energy Act[15] ("NEA"), which is in effect from 1 January 2017. The NEA introduces a number of new features aimed at increasing the level of protection against the harmful effects of nuclear energy and ionising radiation. The new legislation transposes the latest Euratom norms and standards of the International Atomic Energy Agency ("IAEA"). The State Office for Nuclear Safety[16] is responsible for the governmental administration and supervision of nuclear energy use in the Czech Republic.

E. Upstream

The market for upstream oil and gas activities is small and there are no shale gas activities. The largest territory with oil and natural gas reserves is the area known as the Vienna basin. Another territory with considerable natural gas reserves is the Upper Silesian basin. However, these reserves are minor in comparison with other countries. The leading companies engaged in exploring for and extracting oil and gas in the Czech Republic are MND a.s., Lama Energy Group, Unigeo a.s. and Green Gas DPB, a.s.

MND, a.s., a member of MND Group, specialises in exploring and extracting crude oil and natural gas in the Czech Republic. MND, a.s. also builds and operates underground gas storage facilities, and sells gas from its own production to retail consumers in the Czech Republic. There is no export of hydrocarbons from the Czech Republic.

Lama Gas & Oil s.r.o., a member of the Lama Energy Group, and Unigeo, a.s. are two companies that are also authorised to explore for and extract crude oil and natural gas. Green Gas DPB, a.s. focuses only on the extraction of natural gas from closed underground mines in the Silesian region.

Mining activities can be carried out only under a concession issued by the Czech National Council on Mining Activities[17] and under the Mining Act[18].

F. Renewable energy

F.1 Renewable energy

The regulatory regime relating to renewable energy is set out mainly in the Act on Supported Energy Sources[19] ("SESA").

The SESA defines renewable energy as non-fossil natural sources of energy. This can include wind, solar, geothermal, water, soil, air, biomass, landfill gas, sludge gas energy from wastewater treatment plants and biogas.

The scope of the SESA includes the regulation of the following:

- guarantees of origin for energy from renewable sources;
- funds to support the market competitiveness of energies from renewable sources by granting subsidies to operators to bridge the cost difference;
- levy on electricity from solar/PV; and
- market conditions for achieving the national targets on energy from renewable sources taking into consideration consumer interests to minimise the economic impacts of support for renewable energies on energy prices.

Under the SESA and Investment Incentives Act[20], the TSO is under no specific obligation or commercial incentive to invest in additional capacity to service renewable energy plants. However, RES operators have a right of priority connection to the distribution network.

F.2 Renewable pre-qualifications

The currently active RES operational support scheme allows producers to choose from 'feed-in tariffs' or 'green bonuses'. Under the feed-in tariff, producers sell electricity to obligatory purchasers at a fixed minimum price. Under the green bonus scheme, producers sell electricity on the electricity market for the market price and are entitled to receive an additional fixed amount. The feed-in tariff scheme does not apply to newly constructed RES with capacity over 1MW, which should be supported through an auction scheme in the future (with the exception of photovoltaic (PV) plants, for which auctions are not planned).

In order to qualify for the current operational support scheme, producers must comply with the requirements of the SESA and Energy Act, such as:

- obtain an electricity generating licence from the ERO;
- conclude a grid connection agreement with the respective DSO; and
- fulfil technical and economic parameters set out in the decrees implementing the SESA.

F.3 Biofuel

The Biofuel Directive was transposed into the Fuel Act[21] and the Air Pollution Act.[22]

The Fuel Act defines biofuel as liquid or gaseous fuel for use in transport and produced from biomass. In the Czech Republic, the main sources of biomass are wood products or sorted waste. Biofuels are mainly produced from rapeseed, sugar beet, wheat or corn. Due to efforts to prevent the indirect land use change impacts of biofuels ("ILUC"), first generation, crop-based biofuels are capped at 7% of total road and rail transport fuels and are to be gradually phased out for low-ILUC biofuels. The Air Pollution Act sets out the minimum required target of biofuels to be included in motor fuels that are put into circulation in the Czech market for the calendar year. The required amount of biofuel is 5% for gasoline and 7% for diesel. The act also allows for the transfer of any biofuel content exceeding the minimum requirement target in any given year towards the fulfilment of the target in the subsequent year (up to 0.2% of the volume requirement). The Air Pollution Act further sets an obligation for producers, importers and distributors of biofuels to evidence the certificate of conformity with sustainability criteria of biofuels.

G. Climate change and sustainability

G.1 Climate change initiatives

Under the EU Climate Change Package, the national target is to reach a 32% share of energy sources and 14% share of transport fuels produced from RES by 2030. The current share of RES ranges around 13.56% out of all national energy sources. The above target should be achieved through investment subsidies for the construction of new RES.

G.2 Emission trading

The national legal framework for greenhouse gas ("GHG") emission trading includes the following acts and regulations:

- Greenhouse Gas Allowances Trading Act;[23]
- Ozone Depletion Act;[24]
- Air Protection Act;[25] and
- Regulations of the Ministry of the Environment.

Following its obligations undertaken in the Paris Climate Change Agreement effective as of 4 November 2016 ("Paris Agreement"), the Czech Republic has committed to reducing its GHG emissions by 16% in the period from 2020 to 2030 and by a further 60% to 65% after 2030, in comparison with 2005 levels. The Czech Republic ratified the Paris Agreement on 5 October 2017.

The Czech Republic combines the European system of emission trading ("EU ETS") and the Kyoto Protocol mechanisms (eg the mechanisms of clean development, projects of common realisation and international emission trading).

G.3 Carbon pricing

Carbon pricing in the Czech Republic consists of fuel excise taxes and to a smaller extent permit prices from the EU ETS. As of June 2021, the Czech Republic does not have an explicit carbon tax. For carbon emission trading, see section G.2.

G.4 Capacity markets

As of June 2021, there are no plans to implement capacity markets in the Czech Republic

H. Energy transition

H.1 Overview

According to the State Energy Concept, which is a key strategic document for development in the energy sector, the Czech Republic plans to gradually phase out its coal energy sources in the next decade and to reach carbon neutrality in 2050. This should be achieved by the construction of new nuclear energy sources (in order to constitute about 50% of electricity produced domestically) and by investment subsidies for the construction of renewables.

H.2 Renewable fuels

Hydrogen

On 27 April 2020, the Czech government adopted an update of the National Action Plan for Clean Mobility ("NAPCM") with the prediction that there should be about 58,000 hydrogen fuelled vehicles by 2030 and 15 hydrogen fuelling stations by 2025.

The main areas identified where further progress is needed in creating a regulatory framework for hydrogen mobility are in particular:

- establishment of a legal obligation for newly constructed and reconstructed parking lots to include a defined number of parking spaces for hydrogen fuelled cars;
- modification of the permitting process for construction of hydrogen infrastructure;
- transposition of existing ISO standards for vehicle service into the Czech legislative environment; and
- creating a framework for further research and development in the hydrogen fuel sector.

As of June 2021, no specific legislation relating to hydrogen fuel has been adopted.

Ammonia

There are no specific plans for the use of ammonia.

H.3 Carbon capture and storage

The CCS Directive was implemented into Czech law in 2012, through the Geological Storage of Carbon Dioxide Act[26] ("GSCD Act"). The GSCD Act regulates the storage of CO_2, and amends other legislation (eg the Mining Act,[27] the Act on Geological Works,[28] the Emission Allowance Act,[29] the Water Act,[30] the Waste Act,[31] and the IPPC Act [32]).

There have been several experimental projects related to the geological storage of CO_2. These projects addressed, among other things, the feasibility of geological storage and the issue of the selection of suitable sites for storing CO_2. The route that has been chosen in the Czech Republic is to permit the storage of CO_2 in natural rock structures, with certain restrictions. To date, however, there are no carbon capture and storage ("CCS") facilities in the Czech Republic.

H.4 Oil and gas platform electrification

The Czech Republic has no oil and gas platforms.

H.5 Industrial hubs

As of 2021, there are 11 big industrial territorial clusters and dozens of other smaller industrial hubs in the Czech Republic located mostly along the existing highway network.

Development of industrial hubs is supported through the MIT's Operational Programme Enterprise and Innovation for Competitiveness ("OP-IEC") and Smart Parks for the Future programme. Under the OP-IEC, the following activities may be subject to a subsidy:

- Collective research: projects must meet the conditions set out in the definition of collective and pre-competitive research. The implementation of collective research projects within the international Cornet network is also subsidised.

- Shared infrastructure: establishment/development and equipment of an open access cluster centre for the purposes of industrial research, development and innovation.
- Internationalisation of the cluster: establishing cooperation in the European Research Area, involvement in cross-border networks of excellent clusters (with an emphasis on future challenges and key technologies), coordinated approach to third markets, etc.
- Development of the cluster organisation: activities leading to the expansion of the cluster and increasing the quality of its management, improving cooperation, knowledge sharing, marketing, networking, etc.

In 2022, OP-IEC is expected to be replaced by the Operational Programme Technology and Applications for Competitiveness ("OP-TAC"). As of June 2021, the OP-TAC is in the final legislative preparatory stage.

H.6 Smart cities

In the Czech Republic, smart city solutions are not regulated and promoted at the central level by the Czech Government but rather at the regional and municipal levels. Individual smart city concepts are coordinated by the Ministry of Regional Development through Smart Cities Methodology ("SCM"). The SCM provides basic guidelines for regional and municipal local authorities for the preparation and implementation of smart city concepts. The SCM contains the three basic pillars of a smart city: mobility, energy, information and communication technologies.

I. Environmental, social and governance (ESG)

ESG is slowly becoming an issue in the Czech Republic mostly due to the implementation of EU Green Deal requirements and other EU legislation.

In 2017, the Czech Republic transposed the NFRD into national legislation through the Accounting Act,[33] under which large companies with over 500 employees that are subject to public interest are required to publish reports on the policies they implement in relation to environmental protection, social responsibility and treatment of employees, respect for human rights, anti-corruption and bribery, and diversity of company boards.

Currently, there are no specific ESG issues affecting investments in the energy sector. However, discussions on the further implementation of ESG principles are ongoing.

Endnotes

1. See www.cez.cz/en/cez-group/cez-group.html.
2. Act No. 458/2000 Coll. on Business Conditions and Public Administration of the Energy Sectors, the Energy Act (*Zákon o podmínkách podnikání a o výkonu státní správy v energetických odvětvích a o změně některých zákonů*).
3. Decree No. 408/2015 Coll., on Electricity Market Rules (*Vyhláška o pravidlech trhu s elektřinou*).
4. Act No. 406/2000 Coll., on Energy Management (*Zákon o hospodaření s energií*).
5. Regulation No. 195/2015 Coll., on the Manner of Price Regulation and on Procedures for Price Regulation in Electricity and Heat Generation (*Vyhláška o způsobu regulace cen a postupech pro regulaci cen v elektroenergetice a teplárenství*).
6. *Zásady cenové regulace pro regulační období 2021-2025 pro odvětví elektroenergetiky, plynárenství, pro činnosti operátora trhu v elektroenergetice a plynárenství a pro povinně vykupující.*
7. Decree No. 359/2020 Coll., on Electricity Metering (*Vyhláška o měření elektřiny*).
8. Decree No. 349/2015 Coll., on Gas Market Rules (*Vyhláška o pravidlech trhu s plynem*).
9. Decree No. 344/2012 Coll., on State of Emergency in the Gas Sector and on Securement of Gas Supply Security Standard (*Vyhláška o stavu nouze v plynárenství a o způsobu zajištění bezpečnostního standardu dodávky plynu*).
10. Decree No. 195/2015 Coll., on Methods and Proceedings of Price Regulation in the Gas Sector (*Vyhláška o způsobu regulace cen a postupech pro regulaci cen v plynárenství*).
11. *Zásady cenové regulace pro regulační období 2021-2025 pro odvětví elektroenergetiky, plynárenství, pro činnosti operátora trhu v elektroenergetice a plynárenství a pro povinně vykupující.*
12. Act No. 165/2012 Coll., on Supported Energy Sources (*zákon o podporovaných zdrojích energie a o změně některých zákonů*).
13. Decree No. 408/2015 Coll., on Electricity Market Rules (*Vyhláška o o pravidlech trhu s elektřinou*).
14. Act No. 229/1992 Coll., on Commodity Exchanges (*Zákon o komoditních burzách*).
15. Act No. 263/2016 Coll., on Nuclear Energy (*Atomový zákon*).
16. See www.sujb.cz/en.
17. Act No. 61/1988 Coll., on the Czech National Council on Mining Activities, Explosives and State Mining Administration (*Zákon o hornické činnosti, výbušninách a o státní báňské správě*).
18. Act No. 44/1988 Coll., on Mining and Several Decrees of the Czech Mining Office (*Horní zákon*).
19. Act No. 165/2012 Coll., on Supported Energy Sources (*Zákon o podporovaných zdrojích energie*).
20. Act No. 72/2000 Coll., on Incentives (*Zákon o investičních pobídkách*).
21. Act No. 311/2006 Coll., on Fuel (*Zákon o pohonných palivech*).
22. Act No. 201/2012 Coll., on Air Pollution (*Zákon o ochraně ovzduší*).
23. Act No. 383/2012 Coll., on Conditions for Greenhouse Gas Allowances Trading (*Zákon o podmínkách obchodování s povolenkami na emise skleníkových plynů*).
24. Act No. 73/2012 Coll., on Substances that Deplete the Ozone Layer and on Fluorinated Greenhouse Gases (*Zákon o látkách, které poškozují ozonovou vrstvu*).
25. Act No. 201/2012 Coll., on the Protection of Clean Air (*Zákon o ochraně ovzduší*).
26. Act No. 85/2012 Coll., on the Geological Storage of Carbon Dioxide (*Zákon o ukládání oxidu uhličitého do přírodních horninových struktur*).
27. Act No. 44/1988 Coll., on the Protection and Utilisation of Mineral Resources (*Zákon o ochraně a využití nerostného bohatství*).
28. Act No. 62/1988 Coll., on Geological Works (*Zákon o geologických pracích*).
29. Act No. 383/2012 Coll., on the Terms of Greenhouse Gas Emission Allowance Trading (*Zákon o podmínkách obchodování s povolenkami na emise skleníkových plynů*).
30. Act No. 254/2001 Coll., on Water (*Zákon o vodách a změně některých zákonů*).
31. Act No. 185/2001 Coll., on Waste (*Zákon o odpadech a o změně některých dalších zákonů*).
32. Act No. 76/2002 Coll., on Integrated Pollution Prevention and Control (*Zákon o integrované prevenci a omezování znečištění, o integrovaném registru znečišťování a změně některých zákonů*).
33. Act No. 563/1991 Coll., on Accounting (*Zákon o účetnictví*).

Energy law in Denmark

Recent developments in the Danish energy market

Carsten Tolderlund, partner, BOPA Law, Copenhagen

Forging ahead with the green transition

Following on from the 2018 political agreement on the general Danish energy policy towards 2050, Denmark has witnessed continued strengthening of the green agenda and of the controls required to monitor adherence to policies and targets. A key driver of this development is the Danish Government's publicly declared intention to place Denmark among the front runners of the green transition process.

The development, although mainly following an EU track, also follows an entirely national track independent to that of the EU, but with clear references to the United Nations Framework Convention on Climate Change (UNFCCC) goal of limiting global warming to 1.5°C. (as embedded in the Paris Agreement); national endeavours are pursuing a narrower and more climate oriented goal compared to the focus at EU level.

Legislative measures

The new 2020 Climate Act

On 6 December 2019 eight out of the ten parties in the Danish Parliament signed an agreement to adopt a new Danish Climate Act during the first half of 2020. The agreement was lauded as a ground-breaking achievement but in reality merely reflected what the political parties had already committed to during the 2019 general election campaign and the subsequent new government plan as at 27 June 2019.

On 18 June 2020 Denmark's first Climate Act with legally binding climate targets became a reality and set the agenda for the Danish energy market. The Climate Act sets out two binding climate targets:

- a 70% reduction in Denmark's emission of greenhouse gases by 2030 compared to 1990 levels; and
- a net-zero target by 2050 with reference to the Paris Agreement.

The Act contains a mechanism for setting milestone targets under which the government must set a legally binding target with a ten-year perspective. This must take place every five years. The newly set target must be more ambitious than the former target (no backsliding). Following political agreement in May 2021, the Act's target of 70% was supplemented by an indicative milestone target of 50%–54% by 2025.

The Act sets out that the Danish Government will develop annual Climate Action Plans that outline concrete policies to reduce emissions for all sectors, including: energy, housing, industry, transportation, energy efficiency, agriculture and land use change and forestry.

The Danish Council on Climate Change will present its professional assessment of whether the initiatives in the Climate Action Plan are sufficient to achieve the targets set.

Since its inception, a plethora of initiatives within energy and industry have been tabled as part of the annual Climate Action Plans such as:

- easing of electricity levies;
- funding for tenders for production of green gases, including biogas;
- funding for CO_2 capture and storage ("CCS");
- subsidies for electrification and increased energy efficiency;
- cessation of oil and gas production by 2050 and cancellation of the eighth licensing round; and
- establishment of two energy islands.

EU Energy Union - the five dimensions

The EU Regulation on the Governance of the Energy Union and Climate Action came into force in December 2018. One of the key elements of the new regulation is that EU Member States must work out an integrated national energy and climate plan ("NECP") for the period 2020-2030 covering all five dimensions of the EU Energy Union.

While there is overlap with the objectives pursued by the Climate Act, the perspective of the EU Regulation is altogether wider.

Denmark submitted its NECP on 20 December 2019. Reference is made in the plan to the political agreement of 6 December 2019 on a new Climate Act and the Climate Action Plans that will contribute to ensuring that national reduction targets are met. In the report's overview of the 'key objectives, policies, and measures', a number of the still valid items that formed part of the June 2018 political agreement are restated, including:

- Decarbonisation: technology-neutral renewable energy tenders, three new offshore wind farms of at least 800MW each, reduction of the electrical heating tax, reduction of the electricity tax, support of geothermal energy, and an analysis on modernising heat;
- Security of supply: allocation of funding that sets a course towards a renewable energy share of approximately 55% by 2030 and increased interconnectivity;
- Internal Market: smart meter roll-out, creation of a datahub, online price comparison tool, change of law with stricter rules for vertically integrated companies;
- Research, innovation, and competitiveness: spending target

of about Kroner 2 billion (DKK) on research, development, and demonstration of new technologies related to energy and climate.

The government's officially declared ambition is that Denmark will be a front runner in the course towards a green transition, and that Denmark 'must be known as a nation of green entrepreneurialism'. While funding for the research, development, and demonstration of new technologies serves the longer-term objective of enabling concrete reductions by 2030 and 2050, the shorter-term commercial benefits associated with opportunities for exports of green technologies cannot be underestimated.

Oil and gas – end date for production and halt to all new licensing rounds

In December 2020, a broad majority in the Danish Parliament reached an agreement on the future of Danish oil and gas production (North Sea Agreement 2020). The North Sea Agreement 2020 constitutes, among other things: (1) a cut-off date of 31 December 2050 for all oil and gas extraction; (2) a cancellation of the eighth licensing round, all future licensing rounds, and the open-door procedure (however, two procedures, ie the mini-rounds and neighbour-block procedures, still exist); and (3) reduction of the geographic area for issuance of licences. According to the government, the agreement sets the direction towards a climate neutral Denmark. The North Sea Agreement 2020 was implemented by an amendment to the Subsoil Act passed through Parliament in December 2021 and entered into force with effect from 1 January 2022.

Gas: alignment of legislation to cater for gas supply from renewable sources

The Natural Gas Supply Act was amended (by way of amending the statute of 18 May 2021) to include gas from renewable sources, to attain an efficient framework for gas distribution companies, and to adjust the market design for the Danish retail gas market.

The terminology of the Act has been revised and adapted to suit the transition from supply of fossil gases to gas from renewable sources. All gas, irrespective of origin, is termed 'gas' and the act itself has been given the name 'the Gas Supply Act'.

One of the purposes of the Act, as an element in the transition to a green gas system, is to ensure that tenders for support can be held for upgraded biogas and other gases from renewable energy sources in the period 2022-2030, and that tenders can be held for support for the production of chemical fuels or products from electricity (Power-to-X) in the period 2022-2030.

The amending Act ensures compliance with Directive (EU) 2018/2001 of 11 December 2018 on the promotion of the use of energy from renewable sources.

Carbon capture and storage: legislative changes

With effect from 1 July 2022 the Danish Subsoil Act was amended to cater for full scale carbon storage licensing (offshore, coastal, and onshore) and pilot projects relating to the same.

The first licensing round for carbon storage on the continental shelf was issued 9 August 2022 with reference to the acreage available for licensing and including provision for state participation in licenses awarded in the shape of the North Sea Fund (as has been the case in respect of oil & gas licensing).

Public consultations with regard to carbon storage in coastal waters and onshore have been carried out late 2022 and will continue throughout the first half of 2023.

On 12 January 2023, the EU Commission approved the Danish carbon capture and storage support scheme allocating 1.1 billion Euro for the propagation and development of CCS technologies. The support is to be granted through a competitive tender process expected to be completed towards the end of 2023. Support granted is to be based on a contract term of 20 years.

Energinet: amendment of the act governing energinet (the Danish TSO)

At the end of 2020 an act was passed introducing certain significant changes to the legal framework governing Energinet, the Danish TSO. The purpose was, among other things, to align the direction of Energinet with the objectives of the Climate Act and the earlier political agreement of 2018. It is stated that changes will ensure a transparent, efficient, and forward-looking development and expansion of its overall electricity and gas infrastructure and support the continued development of energy infrastructure towards a climate neutral energy supply. The changes also introduce mandatory presentation to the Climate, Energy, and Supply Committee of certain projects of more significance before final approval (including projects that involve international energy connections). This amendment will be seen in conjunction with executive order no. 1048 of 2021-05-28 no. 1047 on system responsible operation and use of the gas transportation system.

Other developments

Renewables

Two energy islands - a new era

In June 2020, the Danish Parliament decided to begin preparations for the construction of two energy islands in Denmark, in the North Sea and in the Baltic Sea, thereby marking the beginning of a new era for large-scale offshore wind power. The energy island at Bornholm will have a capacity of 2GW, while the installation in the North Sea will have a capacity of 3GW in 2030, and 10GW in the longer term. This will be sufficient to meet the average electricity consumption of five million households (in the short term).

The North Sea installation will be placed some 80 kilometres from the coastline (at Thorsminde, a coastal town in West Jutland) and will be connected via cables to Denmark and to the grid of at least one more country.

The island in the Baltic Sea will be placed some 20 kilometres off the coast south of Rønne, Bornholm and will be connected via cables to Denmark (Bornholm) and at least one more country.

Energinet is currently carrying out the preparatory environmental studies and seabed surveys, expected to be finalised in 2024.

Power-to-X

The Act on the Promotion of Renewable Energy, cf. Executive Order No. 125 of 7 February 2020 (the Renewable Energy Act), does not authorise the Minister of Climate, Energy, and Supply to hold tenders for support for the production of chemical fuels or products from electricity (Power-to-X). A new provision has therefore been inserted in the Renewable Energy Act (§ 43 k) authorising the Minister of Climate, Energy, and Supply to hold tenders for support for the production of Power-to-X in the period 2022-2030. The subsidy scheme, based on a tender process in respect of a fixed price surcharge, is expected to be launched in 2023, subject to its approval by the EU Commission.

Several projects are underway, but there is growing recognition for the need to streamline approval processes. The three industry associations Wind Denmark, Dansk Energi, and Dansk Solkraft have recently proposed in a letter to the parliamentary energy committee that a dedicated Power-to-x task force be established to ensure a smooth approval process and to act as a one-stop-shop for both domestic and foreign Power-to-x players and investors.

Market news

Oil and gas

Approval of total and noreco transactions

The acquisition by Total of Chevron Denmark Inc. (holding about a 12% non-operating interest in the Danish Utility Regulator ("DUC")) was closed on 1 April 2019 and the acquisition by Noreco of the entire Danish assets of Shell (holding a 36.8% in the DUC) completed in August 2019.

Ineos acquires Hess

In March 2021, Ineos announced a US$150 million deal to buy the oil and gas assets of Hess Corporation in Denmark. The transaction was closed with regulatory approval in August 2021. The acquisition comprises a 61.5% stake of the Hess-operated Syd Arne oilfield, adding to the 36.8% stake Ineos already held, and a 4.8% interest of the Ineos-operated Solsort field.

Ineos currently operates the Siri field in Denmark and, by becoming operator of Syd Arne, it expects to unlock operational and cost synergies between the two assets, particularly around its Greensand CCS project.

Renewables

The 2018 political agreement on the establishment of three new 800MW+ windfarms

As part of the Energy Agreement of 29 June 2018, all political parties in the Danish Parliament have agreed to establish three new offshore wind farms before 2030. To date, two windfarms have made progress:

- Thor Windfarm: Thor Wind Farm I/S, a consortium of RWE AG, RWE Renewables GmbH, and RWE Renewables Management UK Limited, won the concession to build Thor offshore wind farm in Denmark following a lottery held on 1 December 2021. Thor offshore wind farm will be the largest offshore wind farm in Denmark and will be located off the coast of Thorsminde on the west coast of Jutland. The expected capacity will be 1000MW with commissioning in 2027. This is the first time a tendering procedure has been completed for offshore wind energy in Denmark without aid. When power is produced, the consortium is expected to pay DKK2.8 billion to the Danish state within just a few years.
- Hesselø Windfarm: The wind farm is to be placed north of Zeeland in Kattegat, in Hesselø Bay, at a distance of 30km from Zeeland and around 20km from the small island, Hesselø. However, in Q2 2021 the tender for Hesselø OWF was put on hold due to the results of preliminary site investigations revealing soft clay formations. On the basis of the geophysical and geotechnical reports and data, the Danish Energy Agency has had technical discussions with potential bidders to ascertain the attractiveness of the tender and if any modifications to the tender should be considered with reference to the site conditions and its consequences.

Interconnector: Viking Link

National Grid and Energinet announced in December 2018 that they had entered a Joint Ownership and Operations Agreement to construct and operate the 760km long, 1400MW high voltage direct current (HVDC) electricity interconnector between Bicker Fen in Lincolnshire, Great Britain and Revsing in southern Jutland, Denmark. The announcement followed receipt of UK planning permission for the section of the interconnector located in East Lindsey District Council, UK. The construction work is ongoing with expected commissioning in 2023.

Interconnector: COBRA Link

On 7 September 2019, the 'green cable' between the Netherlands (Eemshaven) and Denmark (Endrup) became operational. The subsea high-voltage direct current cable of about 325km has a capacity of 700MW.

The COBRA cable is an initiative of the Dutch high-voltage grid operator TenneT and Energinet.

Biogas

In October 2021, Canadian company Anaergia Inc. announced its acquisition of two Danish subsidiaries that will build, own, and operate a new anaerobic digestion facility in Tønder, Denmark. This new facility will take in agricultural waste and convert it to renewable natural gas. Production is anticipated to begin before 31 December 2022 with an expected capacity to meet the needs of around 29,000 homes. Investment is in excess of CAN$100 million.

Carbon capture and storage

The Danish Energy Agency has on 6 December 2022 granted the first-ever permit (under the pilot scheme pursuant to the Subsoil Act) for a CO_2 storage project in Denmark to a consortium consisting of Ineos E&P and Wintershall Dea. The project includes the injection and storage of up to 15,000 tonnes of CO_2 in a former oil field over a four-month period. The permit allows up to 15,000 tonnes of CO_2 to be injected in the project's pilot phase, in the former Nini West oil field, and is valid for a period of four months, expiring on 1 April 2023.

Overview of the legal and regulatory framework in Denmark

A. Electricity

A.1 Industry structure

Nature of the market

The Danish electricity market is divided into a wholesale and a retail market, and market participants act within their individual framework of responsibilities. The wholesale market is further divided into three sub-markets, ie markets for day-ahead, intraday, and ancillary services. The retail market is where Danish consumers buy their power.

While Denmark has duly implemented the EU liberalisation directives resulting in a fully liberalised supply market and a grid unbundled at the transmission level, the dynamic development of the green transition, with increased decentralised production characterised by greater output fluctuation, places further stern demands on the overall structure of the electricity market to ensure flexibility and transparency and not least that transmission does not constitute a barrier to this transition. Efficient access to the market and focus on mechanisms to solve any resulting imbalance between production and demand are key areas.

The 2020 Climate Act (*Lov om klima*)[1] has as its objective the reduction of greenhouse gases ("GHG") by 70% in 2030 and climate neutrality in 2050. Another primary objective is that Denmark will be seen as a frontrunner in the transition to green process.

In 2020, 60% of the electricity consumed by the Danish power sector came from renewable energy sources ("RES"), making it the country with the highest renewable energy share in its power system. It is anticipated that these sources will make up close to 100% of all electricity consumption by 2030. A large part of the increase in consumption is expected to be adjustable like power-to-heating, charging of electric vehicles, smart buildings, and production of biofuels through electrolysis and certain industrial processes.

Key market players

Depending on the definition of a key market player, the dominant forces on the Danish electricity wholesale market include SEAS-NVE with a market share of 40% (acquired Radius from Ørsted in 2020), Norlys with 30%-40% (the result of a merger between Eniig and SE, approved by merger control in 2019), Vattenfall, NRGI and Energi Danmark A/S.

Regulatory authorities

Overall regulatory responsibility for and supervision of the energy industry as a whole is vested in the Ministry of Energy, Utilities, and Climate Control (*Energi-, Forsynings- og Klimaministeriet*) (the "Ministry").

The Danish Energy Agency (*Energistyrelsen*), an agency under the Ministry ("DEA"), has been delegated the tasks linked to energy production, supply, and consumption, as well as Danish efforts to reduce carbon emissions.

The DEA develops the legal framework for production, transmission, and distribution of electricity, and for competition, consumer protection, and security of supply. This includes the power under the Danish Electricity Supply Act to issue executive orders and to supervise and control adherence to the act.

The Act on the Danish Utility Regulator (*Forsyningstilsynsloven*) of 1 July 2018 established the Danish Utility Regulator (*Forsyningstilsynet*) ("DUR"). The Act seeks to maintain strong and effective supervision of the utility sectors, ie electricity, natural gas and district heating. The DUR, among other things, regulates and benchmarks prices for services from the electricity distribution companies and administers the economic regulation of Energinet, the Danish Transmission System Operator ("TSO").

The Energy Board of Appeal (*Energiklagenævnet*) is the administrative appeal body that hears appeals of decisions taken by the DEA, Energinet, and the municipalities within the area of energy.

The Energy Supplies Complaint Board (*Energiankenævnet*) is a private complaints board that handles complaints regarding purchases and delivery of energy services to consumers.

The purpose of Energinet, the Danish TSO, is to own, operate, and develop the overall energy infrastructure and manage related tasks. Energinet is an independent public entity established pursuant to the Act on Energinet and is, to all intents and purposes, subject to the control of the state. Energinet must ensure open and equal access to the transmission networks for all users. Following an amendment to the Act on Energinet, support of the continued development of energy infrastructure towards a climate-neutral energy supply has been added to the list of Energinet's tasks, among other things.

Legal framework

The Danish Electricity Supply Act (*lov om elforsyning*) ("ESA") and all executive orders issued under this act constitute the general regulatory framework to which the Danish electricity market is subject.

Implementation of EU directives

Following the implementation of the effective separation of supply and generation activities from network operations pursuant to the directives of the third energy package, the Danish transmission grid is entirely unbundled with Energinet being the state-owned enterprise responsible for the operation of the transmission grid and the electricity system in Denmark.

A.2 Third party access regime

Access to the grid is free for everyone although a fee must be paid for use of the system. A supplier must fulfil a number of technical criteria and standards, including relating to IT, which are required to uphold and sustain the technical integrity of the system. Connection to the system is facilitated by the supplier and the network company entering into an agreement. The agreement can either be in the standard format prepared by Dansk Energi (as the relevant trade organisation) and approved by DUR, or the parties can opt to agree the entry terms based on the network company's own standard form provided this is registered with and has been approved by DUR.

A.3 Market design

Geographically situated between continental Europe and the rest of Scandinavia, Denmark's western electrical grid is part of the synchronous grid of Continental Europe, whereas the eastern part is connected to the synchronous grid of Northern Europe via Sweden. Nord Pool Spot runs the power wholesale market in northern Europe and offers both day-ahead and intraday markets; 380 companies from 20 countries trade on the market. Nord Pool Spot is owned by the Nordic and Baltic TSOs (in Denmark, Energinet). The price of power is determined by the difference between supply and demand. Factors such as the weather or power plants not producing to their full capacity may affect how much power can be transported through the grid and may therefore influence the price of power.

The electricity spot market, known as the Day-Ahead Market, has proven instrumental in integrating a high share of variable renewable energy in Denmark. Nord Pool is the main day-ahead power exchange in Denmark and operating over Nordic and Baltic countries.

The intraday market is also handled via Single Intraday Coupling (SIDC – formerly XBid), the IT-based trading mechanism that brings the Pan-European intraday continuous market together and complements the existing day-ahead market. This market is growing due to the increase in the share of RES in the mix, and on the drawing board for SIDC are, among other things, intraday auctions.

A.4 Tariff regulation

Under the ESA, fees for services delivered by the distribution and net transmission companies are to be determined in accordance with the annual revenue framework. This sets the maximum amount(s) (income cap) that a company may charge as part of its revenue derived from its operations as holder of an authorisation to distribute/transmit electricity. All such fees are subject to overall approval by DUR.

The most recent executive (income cap) order was issued on 27 June 2022. The aim of this executive order is to compute the annual revenue framework, based on certain parameters, commensurate with the operating costs of the Distribution System Operator ("DSO") and a return on the invested capital. The latter is viewed on both a historic and forward-looking basis. The factual basis on which DUR establishes the annual revenue framework for a DSO are adjustment accounts which a DSO is obliged to submit to DUR. As part of this process, DUR conducts a benchmarking exercise of the (financial) efficiency of the DSOs.

Of particular interest, and to be seen in conjunction with the green transition, is a particular provision for upwards adjustment of the revenue framework for new grid connections involving RES. However, for renewable energy suppliers some uncertainty exists when the geographically differentiated connection fee,feed-in-tariffs for the distribution grid and the transmission grid are introduced for new renewable energy suppliers (as from 1 January 2023), thereby abolishing the current financial equalisation scheme. There is political concern in some quarters that this will pull the rug out from under these suppliers. No solution was in sight at the time of writing.

For suppliers, tariffs are generally composed of a connection fee and a feed-in tariff with the consumers paying the grid and system tariff relating to the TSO's costs of operating and maintaining the national and regional transmission grids. These costs appear as separate items on any bill issued to the electricity consumer.

Energinet's tariffs for 2022 are the following, expressed in øre/KWh (one øre is 1/100 of DKK 1.00 = approximately €0.13): grid tariff – 4.9; system tariff – 6.1; and balancing tariff – 0.229.

A.5 Market entry

Electricity production

Generally, the approval and licensing system pursuant to the ESA has undergone significant changes to cater for a new playing field which involves the participation of smaller, decentralised commercial production from renewables. Consequently, the original approval and licensing regime is now reserved/retained for the existing electricity power plants (for reasons related to security of supply) whereas an 'approval only' regime applies to the rest of the field.

With effect from 1 January 2022 all new builds are subject to the approval regime.

For both regimes, approval is required for plants with a power generating capacity above 25kW, issued only to applicants with adequate technical and financial prowess.

There is no distinction between onshore and offshore electricity generation.

Transmission and distribution

All transmission and distribution activities are subject to a licensing regime. Transmission activities for which Energinet is responsible pursuant to the Act on Energinet are exempted. Licences are issued for 20 years. All licences for distribution existing as of 31 December 2020 have been prolonged (without the need for an application) to 31 December 2025. This means that all distribution licences hereinafter will have a start date of 1 January 2026 on equal terms.

Under a bill dated 28 December 2021, modernising changes were introduced to the ESA. The objective of one of these changes was to reinforce the unbundling requirements through a robust administration of the DSOs, including a clear separation of the DSO's licensed operations from its other commercial activities, independence of management from commercial interests, and so on.

To safeguard consumer influence, a minimum of two members of the board of a DSO must be appointed by consumers resident in the supply area of the grid. For DSOs owned/controlled by municipalities or cooperatives of end users, the majority of the board is appointed by consumers in the supply area or through the boards of the municipalities.

Trading

In principle, no licence is required to participate in the wholesale physical market as a trader and no requirements exist concerning residence or presence in Denmark. Participation by any trader is obviously subject to adherence to the rules and regulations governing the trading activity on that particular market. However, to trade as a balance responsible trader, an approval from the TSO is required.

In relation to retail activities involving sales to end users, there are requirements incumbent on the retail seller pursuant to the order on delivery of electricity (Order no. 2648, 28 December 2021) and the Consumer Protection Act.

For financial trading there will be licensing and notification requirements pursuant to the Financial Business Act.

A.6 Public service obligations and smart metering

Public service obligations (PSOs)

The PSO tariff was phased out by the end of 2021. The tariff had been charged by the TSO and ultimately paid by the consumers. It covered, among other things, subsidies to the renewable energy industry and costs of associated research. These costs now form part of the annual public budget.

Smart metering

By 2020, all Danish electricity end users had smart meters installed and are billed on an hourly basis.

Electric vehicles

In December 2020 a political agreement on green road transport was reached between the government and certain left-wing parties in pursuit of attaining the 2030 objective of a 70% reduction in GHG emissions. The basis for the agreement was the ambition to have one million zero or low emission cars on the road in 2030 as recommended by the Danish Climate Council. To achieve this, Danish registration taxes have been revised to support increased substitution of fossil fuelled cars for green cars. In addition, the regime whereby reduced electricity taxes apply to electricity consumed for charging of electric vehicle (EV) batteries has been extended until 2030. Recognising that a national ban on the sale in Denmark of fossil fuelled cars is prevented by the operation of EU law, the government has opted to work for the out-phasing of the sale of these vehicles at EU level.

A.7 Cross-border interconnectors

Denmark has the following interconnector facilities in operation:

Eastern Denmark:

- Denmark-Sweden: two 400kV and two 132kV AC cable connections, which serve as a link to the Nordic grid; the export capacity is 1,700MW and the import capacity is 1,300MW;
- Denmark-Germany: one 400kV DC connection named 'Kontek', which runs from Køge to Hohe Düne; the cable is in the process of being replaced; capacity 600MW; and
- Denmark-Germany: one 170kV AC connection, which links the Danish WF, Kriegers Flak with the German WF, Baltic 2; capacity 600MW.

Western Denmark:

- Denmark-Netherlands: two 320kV DC connections named 'Cobra', which link the Danish and Dutch grids; capacity 700MW;
- Denmark-Sweden: two 285kV DC connections named 'KontiSkan'; capacity 740MW;
- Denmark-Norway: three DC connections, which run under Skage-rak; capacity 1,700MW; and
- Denmark-Germany: one 400kV AC connection, which runs from Kassø and Ensted; capacity 2,500MW.

B. Oil and gas

B.1 Industry structure

Nature of the market

Denmark has produced oil and gas from the Danish part of the North Sea since 1972. Oil and gas production still contributes significantly to state revenue. Some DKK514 billion in revenue has been harvested from the Danish part of the continental shelf.

Denmark is currently a net importer of oil and gas. Once the completion of the redevelopment of the Tyra field is completed in 2023 Denmark will (again) be gas self-sufficient.

In 2020 it was decided to put an end to all new licensing rounds for oil and gas exploration and decree an end date for oil and gas production by 31 December 2050.

Key market players

The key market players are:

- for gas: Energinet (the Danish TSO), HOFOR A/S, OK, Total Energies A/S, Ineos, Evida, Gas Storage Denmark A/S, Dansk Offshore (trade association); and
- for oil: Total Energies A/S, Ineos, OK, Klesch Group (refining, Kalundborg), Dansk Offshore.

Regulatory authorities

The overall regulatory responsibility for and supervision of the energy industry as a whole is vested in the Ministry of Energy, Utilities, and Climate Control (*Energi-, Forsynings- og Klimaministeriet*) (the "Ministry") (see section A.1). Under the Danish Subsoil Act, the tasks concerning upstream oil and gas activities have been delegated to the DEA.

The Danish Working Environment Authority (*Arbejdstilsynet*) is the responsible authority for health and safety on offshore installations and for certain vessels in connection with the exploration for and production of oil and gas.

Legal framework

The Danish Subsoil Act (*Undergrundsloven*) ("DSA")[3] governs oil and gas upstream activities, and the Danish Gas Supply Act (*lov om gasforsyning*) ("DGA")[4] regulates the gas industry (mid- and downstream).

Upstream

The Subsoil Act serves as a framework act applicable to licensing, preliminary investigations, exploration, and extraction of hydrocarbons. The purpose of this Act is to ensure appropriate use and exploitation of the Danish subsoil and its natural resources. It also extends to the use of the subsoil for storage purposes.

All hydrocarbons are the property of the Danish State with exploration and production rights being granted through a licensing system. State participation is regulated by the Act on the Danish North Sea Fund, a Danish state-owned entity, which participates with a 20% non-operating interest in all licences granted, including since 2012, a 20% interest in the DUC consortium, as a non-operating partner.

On 22 February 2018 the Danish Government closed off land and inner Danish waters to oil and gas exploration, and in December 2020 a cut-off date of 31 December 2050 was introduced for oil and gas extraction in the North Sea together with a cancellation of all future licensing rounds. The remaining rules have been nailed down to ensure stability, including access to the two other licensing schemes with limited scope, ie the mini rounds and neighbouring block licence applications. However, any such permits would still have to adhere to the 2050 end date.

Oil and condensate from the North Sea are, with some exceptions, transported via pipeline to refining facilities in Fredericia, Jutland. The upstream transportation of oil and condensate is regulated by the Danish Pipeline Act (*rørledningsloven*). Pursuant to Section 2 of the Act, all oil producers in the Danish part of the North Sea are obliged to use and pay for the upstream pipeline system, the ownership of which is now vested in Energinet.

Natural gas is transported from the North Sea to the processing plant in Nybro, Jutland. The gas upstream pipelines are owned and operated by Energinet, the Danish TSO. There are two natural gas storage facilities on land (Lille Torup, Jutland, and Stenlille, Zealand), both operated by Energinet.

The Danish Gas Supply Act (*lov om gasforsyning*) ("DGA") governs the activities of the natural gas industry. However, this excludes gas transmission in pipelines not connected to the Danish gas transportation system. By amending the statute of 18 May 2021, the Act was amended to include gas from renewable sources, to set out an efficient framework for gas distribution companies and to adjust the market design for the Danish retail gas market.

The DGA applies to transmission, distribution, and storage of gas in the system, including management of liquid gas in the system and to gas from RES technically capable of being safely injected into and transported in the system. The Act also applies to hydrogen from RES not transported in the system.

Implementation of EU directives

DGA incorporates the EU's Third Gas Directive and the amending EU directive 2019/692 of the European Parliament and of the Council of 17 April 2019, which, together with the executive orders issued pursuant to the directive, constitute the legislative basis for the Danish gas market.

Gas

The Danish gas transportation system consists of a general transmission network connecting the various parts of Denmark and a distribution network which distributes the gas to end users. The transmission network is connected to the gas producing fields in the North Sea, Tyra, and Syd Arne, and to Germany and Sweden and to the two storage facilities in Lille Torup and Stenlille. These underground facilities have a combined storage capacity equal to several months of gas consumption. The gas storage facilities contain all excess gas production, particularly from the summer months. The excess production is used to level-out seasonal and daily fluctuations as well as being held as emergency storage in case of supply failure.

The part of the infrastructure nearest to the customers is the distribution system, and this consists of distribution lines and service lines. From the distribution lines, the gas is delivered to the individual consumer's service line.

The liberalisation and consolidation of the gas sector has resulted in Energinet, as the TSO, owning and operating the entire gas transportation system including the two storage facilities on land since 2019.

Gas supply

Gas supply and sales (to end users) is handled by several commercial gas trading companies. As is the case in nearly all markets across the EU in this third decade of a liberalised market, customers of gas are now free to choose their gas suppliers. If that right is not exercised, gas will be delivered from the gas supplier with the gas supply obligation in the area in question. There are currently ten gas suppliers in Denmark.

Commercial gas suppliers buy gas on different gas trading platforms and sell gas to consumers. The primary commercial commodity trading platform in Denmark is Gaspoint Nordic, owned by European Energy Exchange AG since 2020. In 2018 the Danish gas traders traded a volume on this exchange corresponding to 83% of the total Danish gas consumption.

B.2 Third party access regime to gas transportation networks

Third party access to the transportation system is implemented through sections 18 to 20 of the DGA, which gives everyone the right to access the system in exchange for a fee. The system includes all transmission and distribution systems, liquefied natural gas ("LNG") facilities or storage facilities, including linepack, and any service facilities required to facilitate access. Access is given based on objective, transparent and non-discriminating criteria. Access may be denied in the following circumstances:

- if there is a lack of capacity;
- if access would prevent the company (TSO) from carrying out the public service obligations incumbent on it; or
- if serious economic/financial difficulties preclude the entry into contracts that contain minimum purchase obligations (take or pay).

Energinet is now the TSO and owns and operates the entire transportation system. In its General Terms and Conditions for Gas Transport, version 21.0 of October 2021[5], Energinet sets out the rules and tariffs applicable to third party access from 1 October 2021. This latest version incorporates the changes resulting from an executive order of 2021 on 'the system responsible operation and use of the gas transmission grid'.

Entry Point is the physical delivery point at which a shipper delivers gas into the transmission system (from the 'adjacent system') and the transport of natural gas through the Danish gas system commences.

Exit Point is the physical delivery point at which the transport of natural gas through the transmission system ends and where Energinet contractually redelivers natural gas to the shipper.

The requirements, under clause 3.1 of the General Terms and Conditions ("GTCs") include for:

- shippers, gas suppliers, storage consumers, biomethane sellers, direct consumers – must enter into a framework agreement with the TSO[6];
- shippers, direct consumers – must get credit card approval;
- shippers, gas suppliers, storage consumers, biomethane sellers, direct consumers – must be registered in the Register of Players;
- shippers, gas suppliers, storage consumers, biomethane sellers, direct consumers – must conclude an online access agreement;
- gas suppliers – must conclude a Gas Supplier Agreement with the distribution company and IT system to be tested and approved for EDI-based communication; and
- biomethane sellers – must conclude biomethane seller agreement with the relevant network owner and have the right to deliver biomethane to the Danish gas system on the basis of an agreement with the producer of the biogas or the owner of the upgrading plant.

Entry and exit regimes

The Danish model provides the following entry/exit points:

- three entry points at Nybro, Ellund, and the joint balancing zone, where the natural gas enters Denmark and Sweden;
- one entry point for RES. Currently only biomethane, aka bio natural gas, enters the gas system. This allows shippers to virtually upload biomethane to the transmission system;
- joint balancing zone, which makes it possible for gas suppliers to deliver gas to all Danish and Swedish consumers through the gas distribution network and to three large power stations in Denmark (Avedøre II, H. C Ørsted and Skærbæk) which are directly connected to the transmission system; and
- three transit exit points at Nybro, Ellund and the joint balancing zone for export of natural gas.

Energinet's business model includes one common storage point which covers the gas storage facilities at Stenlille and Lille Torup. Storage customers use this point to feed gas into the gas storage facility or withdraw gas from it.

For virtual transfers the Danish gas market model offers shippers two methods of buying and selling gas:

- through Energinet's virtual point ETF (ie, the Exchange Transfer Facility) for trades executed on the Danish gas exchange; and
- through GTF (ie, the Gas Transfer Facility), Energinet's virtual point for bilateral trades in the secondary market.

Title transfer

There is freedom of contract and there are no sector specific regulations applying to transfers of title between an owner/seller and a buyer.

B.3 LNG terminals and gas storage facilities

With the exception of terminal bunkering facilities enabling bunkering of LNG at the port of Hirtshals, there are no LNG facilities in Denmark.

The DGA regulatory framework applicable to transmission and distribution facilities equally applies to LNG facilities and it requires a licence to operate LNG facilities which are subject to the regime on tariffs and third-party access (see section B.2).

The DGA regulation of third-party access applies to the 'system', which also encompasses storage facilities (see section B.2).

The two Danish gas storage facilities are owned and operated by Gas Storage Denmark A/S, a company wholly owned by Energinet. The company publishes its terms on its website. Rights and obligations in relation to storage services are described in Rules for Gas Storage ("RGS")[7]. Starting from 1 April 2022 RGS will be referred to as 'General Terms and Conditions Gas Storage' ("GTCGS"). The RGS and the GTCGS describe terms and conditions in relation to acting as a storage customer, concluding storage agreements, access to firm and interruptible capacity, performing transfers in storage, operational restrictions, and various other aspects.

B.4 Tariff regulation

The Danish TSO, Energinet, sets out its annual transportation tariffs which are subject to the control of DUR, who benchmarks these against other European transportation tariffs. Electricity tariffs, and gas transportation tariffs, are fixed/determined against an annual revenue framework. This sets the maximum amount(s) that a company may charge as part of its revenue derived from its operations as holder of a licence to transport gas. This was introduced by an amendment to the DGA in 2021. The tariffs cover Energinet's operational costs, and the cost of capital invested.

The tariffs cover, among other things, a capacity tariff (calculated on the basis of capacity booked) and commodity tariff (dependent on the volumes of gas transported).

Capacity

The capacity charge is a reservation fee for a shipper's 'right to use' Energinet's gas transmission system capacity, irrespective of the actual gas volume transported through the system. The capacity charge covers 70% of Energinet's annual cost base. Capacity is generally paid for on an annual basis (the gas year runs from 1 October), but Energinet makes provision for shorter bookings.

Tariffs effective as of 1 October 2021:

- Entry charge at Ellund, Nybro, RES, and Joint Exit Zone: DKK20.53/kWh;
- Exit charge at Ellund and Joint Exit Zone: DKK20.53/kWh;
- Commodity charge at Joint Exit Zone and exit points: DKk0.00223/kWh; and
- Balance charge at Joint Exit Zone and exit points: DKK0.00012/kWh.

B. 5 Market entry

Pursuant to the DGA the conduct of gas transmission and distribution activities are subject to a licence (granted for a period of at least 20 years). Energinet is the owner and operator of the entire gas transmission and distribution network. In accordance with the Act on Energinet, no separate licence is required for the conduct of the activities for which Energinet is responsible under the Act.

There are no licence requirements to become a trader, but traders will have to be registered in Energinet's register of players. Shippers can buy/sell gas via Energinet's virtual facilities (ETF and GTF) and Gaspoint Nordic, the primary trading platform to buy and sell gas at market driven prices.

The Danish Financial Business Act (*lov om financiel virksomhed*) may apply to trades which are financial by nature and then, separate requirements (licensing/notification) may apply.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Section 11 of the DGA sets out the PSOs applicable to transmission and distribution system owners (ownership now consolidated in Energinet). In the main the PSOs require the owner/operator to:

- maintain a physical balance in the system;
- uphold adequate transport capacity;
- ensure measurement of the entry and exit of gas in the system;
- give the users of the system all required information about the gas transported in the system;
- ensure the quality of the gas delivered to and from the system (transmission); and
- handle certain assignments in relation to security of supply (transmission).

Smart metering

There is no requirement and no national plan to introduce smart gas metering in Denmark.

B.7 Cross-border interconnectors

The Danish gas system is an integrated part of the European gas infrastructure. With the redevelopment of the Tyra field, Denmark is a net importer of natural gas from Germany via Ellund that links the transmission nets of these two countries and makes both import and export possible. Via a connection at Dragør, Danish North Sea gas is transported to Sweden.

By the end of 2022 it is expected that the Baltic Pipe will be put into operation linking Norway and Poland, partly through a land-based pipeline transmission via Denmark. The project has not been without controversy at local level.

C. Energy trading

C.1 Electricity trading

General

Through transmission connections, Denmark's wholesale electricity market is an integrated part of the Nordic and Baltic market which again connects to the European network. Physical power is traded bilaterally or via Nord Pool Spot which runs the power wholesale physical market in northern Europe and offers both day-ahead and intraday markets. Nord Pool Spot is owned by the Nordic and Baltic transmission systems operators (in Denmark, Energinet). Nord Pool is the main day-ahead power exchange in Denmark taking up 90% of the market (with the rest reserved for bilateral trading). Trade takes place via an auction system where generators and buyers notify the quantities they wish to buy, at what price, and in what electricity region. By matching purchase and sale bids, a market price for electricity for each area is found on the day before it is consumed.

The intraday market caters, among other things, for imbalances resulting from trading at the day-ahead market. This market is growing due to the increase in the share of RES in the mix.

The intraday market is also handled via Single Intraday Coupling (SIDC – formerly XBid), the IT based trading mechanism that brings the Pan-European intraday continuous market together and complements the existing day ahead market. Nord Pool is a nominated electricity market operator (NEMO).

Nord Pool's rules for trading activities are set out in its rulebook which requires trading candidates to conclude a Participant

Agreement and be eligible as counterparty under the Clearing Rules (schedule 4 to the rulebook).

Clearing is automated with Nord Pool becoming the central counterparty in the match-up between seller and buyer. The clearing transaction is ultimately allocated to the clearing account of the relevant clearing member which must be supplemented with a cash settlement account and, if collateral is to be provided, a cash collateral account. Nord Pool may at any time investigate and monitor a clearing member's financial standing.

Specific product specifications for the Nordic and Baltic markets can be found in 'Product Specifications Nordic/Baltic Market Areas' which form part of the Rulebook covering time references, trading hours, particular contract codes and so on.

No specific requirements exist regarding the corporate setup of a participant.

Balance responsible parties ("BRPs") who trade on the Danish market must conclude an agreement with Energinet on balance responsibility.

Energinet has issued regulations C1 – C3[8] to which the BRP must adhere such as the procedure for upholding balance hour-by-hour with a plan for production/consumption to be submitted to Energinet in the afternoon on the day before the relevant operating day. Gate closure occurs at 17:00 hours. Regulation C2 sets out Energinet's organisation of the balancing market where Energinet is responsible for the buying/selling of power from/to the participants to neutralise imbalances.

A BRP will also be registered on DataHub, an electronic communication platform established with the objective to ensure uniform communication methods and standardised processes for professional participants in the electricity market.

There is freedom of contract concerning supply agreements on the wholesale market involving other than end users. However, electricity trading companies ("ETCs") will usually avail themselves of their standard general terms and conditions.

Partly implementing EP/Council directive 2019/944, executive order 2648 of 28 November 2021 covers the supply of electricity to end users (with certain provisions reserved for consumers) and sets out the obligations incumbent on the ETC with regard to transparency, clarity and reasonableness of terms, flexibility (right to change of supplier and costs in this connection), notification requirements, amendment of terms, obligations to offer dynamic contracts in certain cases (reflecting price fluctuations on the spot markets) and requirements as to the dissemination and content of information to customers, both directly and at the ETC's website.

Financial contracts are used for price hedging and risk management. The contracts have a time horizon up to ten years, covering daily, weekly, monthly, quarterly, and annual contracts. The system price calculated by Nord Pool is used as the reference price for the financial market in the Nordic region.

International Swaps and Derivatives Association Agreements (ISDAs) and European Federation of Energy Traders Agreements (EFETs) are customarily used.

C.2 Gas trading

Capacity markets

Shippers in the Danish market have access to book capacity through two different platforms: PRISMA and Energinet Online. The European trading platform PRISMA makes it possible for shippers to book capacities at European interconnection points through a single platform.

Shippers in Denmark, who are registered with PRISMA, can select Energinet as TSO and participate in day-ahead, monthly, quarterly, and yearly capacity auctions of bundled and un-bundled capacity at the Dragør and Ellund entry/exit points.

Energinet online

Shipper-to-shipper capacity transfers are generally executed through Energinet's virtual Capacity Transfer Facility (CTF) booking feature, available at Energinet Online.

Shippers in Denmark, who are registered with Energinet, may book day-ahead, monthly, quarterly, and yearly capacity for the Nybro entry/exit point, RES (biomethane) entry point, and the Joint Balancing Zone.

Commodity markets

Shippers can buy or sell gas through the Energinet operated ETF/Gaspoint Nordic which is the primary commercial commodity trading platform in Denmark, and since 2020 has been owned by European Energy Exchange AG.

Bilateral trades take place through GTF, Energinet's virtual point for bilateral trades in the secondary market.

Contractual requirements

Users of the gas transportation system are subject to the General Terms and Conditions for Gas Transport Version (currently version 22.0 effective as of 1 October 2022)[5] available on Energinet's website. These terms and conditions apply to all players on the Danish gas market (defined as the relevant shippers, gas suppliers, storage customers, and biomethane sellers as well as Energinet, the distribution company and Gas Storage Denmark) and have been updated in the light of the amendment to the Act on Energinet and the executive order of 2021 on system responsible operator and the use of the gas system. The framework rules applicable to the market include:

- conditions for acting as a player (see section B.2);
- register of players;
- capacity agreements (firm and interruptible);
- nominations;
- allocation; and
- balancing regime.

Capacity orders must be submitted at the latest at 17:00hrs on the gas day before the commencement of the capacity period for annual, quarterly, monthly capacities (or capacity periods of another duration calculated in multiples of months) or daily capacities for up to six consecutive gas days.

With regard to balancing, the TSO is responsible for the ongoing balancing of the natural gas supply system. The shipper is responsible for balancing its deliveries and offtake to minimise the need for the TSO to undertake balancing actions. A shipper deemed imbalanced for a gas day will be charged for daily imbalance quantities in accordance with the provisions of the GTCs.

There is freedom of contract as concerns supply agreements on the wholesale market involving other than end users although gas trading companies will usually avail themselves of their standard GTCs.

Customers of gas are now free to choose their gas suppliers. If that right is not exercised, gas will be delivered from the gas supplier who has the gas supply obligation in the area in question. As for electricity, suppliers of gas must offer their services to the customers on terms which are objective, transparent, and non-discriminating (pursuant to the DGA). Relevant consumer protection legislation also applies.

D. Nuclear energy

In 1985, the Danish parliament passed a resolution that nuclear power plants would not be built in the country and there is currently no move to reverse this situation. The public debate on this energy source has however reopened somewhat in recent years, partly due to the EU Commission labelling nuclear power a green investment under the EU taxonomy and, not least, the issues with regard to gas supply arising from Russia's invasion of Ukraine.

E. Upstream

Current state of play

In 2020 it was decided to put an end to all new licensing rounds for oil and gas exploration and decree an end date for oil and gas production by 31 December 2050 (see section B.1). An eighth licensing round was cancelled. On 22 February 2018 the Danish Government closed off land and inner Danish waters to oil and gas exploration.

Regime

The principal legislative basis and general highlights of the way in which the industry is organised are set out in section B.1. The DSA, as latest amended in 2021, incorporates these changes. Anotherprincipal piece of legislation is the Offshore Safety Act, which now falls under the Danish work environment authority (following the implementation of an EU directive).

Exploration and production are subject to licensing with the DEA as the issuing authority. No new licences will be issued apart from licence grants as a result of neighbouring block applications or mini rounds.

All current licences issued are based on a model licence (available on the DEA's website) and an individual work programme for the exploration term as agreed between the licensee and the DEA. Exploration terms are for an initial period of six years and extendable up to a maximum of ten years. Production licences are awarded for a term of 30 years; however all existing production licences are subject to the cut-off date of 31 December 2050.

There has been an ongoing alignment of terms applicable to the area comprised by the original DUC sole concession and the area outside of it, with the Danish North Sea Fund, since 2012, having become a state participant with a 20% non-operating interest in the DUC concession (in addition to the Fund's 20% stake in all licences outside the DUC concession area).

Located in the DUC part of the Danish North Sea, the Tyra gas field is being redeveloped with an investment of DKK25-DKK30 billion (US$3.4–US$4 billion) to extend its operational life by at least 25 years. Tyra has for decades processed 90% of the Danish gas production. Certain tax breaks were agreed with the government in 2017 (the 2017 North Sea Agreement) to enable a redevelopment decision. These tax breaks are universal to all oil and gas development projects in Denmark.

The Tyra field is expected to return to operation in the second part of 2023 with a production rate at circa 60,000 barrels of oil equivalent (boe) per day.

Third party access

As part of the 2017 North Sea Agreement, and also incorporated by amendment to the DSA, a strengthened access by third parties to existing infrastructure was agreed. The driving principle is that revenue from tied-in fields in the main will befall the field owner (taking the risk) rather than the infrastructure owner.

Transfer of licences

Direct transfers of participating licence interests as well as indirect transfers (via a change of control/ownership of a corporate body holding a licence interest) require approval by the DEA and by the co-licensees. In the absence of the use of the right of pre-emption as provided for in the standard joint operating agreements in use on the Danish CS, approval by co-licensees may not be unreasonably withheld provided the assignee can demonstrate adequate technical and financial resources.

Following implementation of the EU Offshore Safety Directive (EP/2013/30/EU) approval by the DEA is, among other things, based on an analysis of the financial capacity of the assignee to be able to fund 'the immediate launch and uninterrupted continuation of measures for effective emergency response and subsequent remediation'. This regime was in fact already in existence, but the directive has meant greater systemisation. In general, a parent company guarantee, uncapped and with unlimited in time, is required.

Decommissioning

Pursuant to licence requirements, a licensee must submit an overall field decommissioning plan for approval by the DEA at least two years prior to the expiry of the licence or the expected abandonment of one or more facilities (whichever is the earlier to occur). The state can exercise a right to take over, without consideration, facilities no longer in use.

In 2015 Denmark introduced secondary financial liability for costs of decommissioning towards the remaining co-licensees for licensees exiting a licence.

F. Renewable energy

F.1 Renewable energy

EU Renewable Energy Directive, EP 2018/2001/EU (REDII) was implemented via amending statute of 12 May 2021 (No. 883) amending the Danish Promotion of Renewable Energy Act (*lov* *om fremme af vedvarende energi*) (REA), originally enacted in 2008.[9]

The amended act, among other things:

- widens the powers of the minister to set requirements for adherence to sustainability criteria and reduction of greenhouse gas emissions as a pre-condition for grants to convert to use of biofuels;
- provides the minister with the powers to set requirements for integration of RES in the transport sector, including requirements for greenhouse gas emissions reduction and use of RES;
- introduces a system for certificates of origin (use of RES) for gas, heating and cooling; and
- introduces powers for the minister to ease the approval processes relating to the establishment of sustainable energy installations.[10]

Further changes are awaited once agreement has been reached with regard to the EU Commission's first and second suite of its 'Fit for 55' package proposal, the key policies of which were politically and provisionally agreed at the end of 2022.

In May 2021 the Commission approved a €400 million Danish aid scheme to support production of electricity from RES. This was to help Denmark reach its renewable energy targets without unduly distorting competition and to contribute to the European objective of achieving climate neutrality by 2050. However, the ensuing 2021 technology neutral tender based on this scheme attracted no bids, industry considering that the shift in the aid model from a fixed-price supplement scheme to a two-sided contract-for-difference format was unattractive. The DEA has assessed the results as part of an analysis of the need for technology neutral tenders after 2021 and concluded that no prolongation of this scheme will be required.

F.2 Renewable pre-qualifications

With tenders for land-based wind farms and solar parks becoming in effect aid free, public financial resources are freed up for other RES projects, notably biogas and Power-to-X ("PtX"). The aid may be granted as a price surcharge or as a construction aid. Pursuant to the DEA an effective implementation/introduction of PtX may be supported by supplementing/sharpening existing CO_2 reduction requirements (including cradle-to-grave based designs similar to the current requirements applied to the transport sector) and adaptation of levies and CO_2 allowances to better reflect the climatic effects of PtX based fuels. On 15 March 2022 the government reached broad political agreement with support from parties across the entire political spectre of the Danish parliament on a new national strategy for PtX with DKK1.25 billion set aside in support/subsidies to speed up the conversion of electricity into green hydrogen and other e-fuels. The new strategy's objective of reaching a 4GW-6GW of electrolysis capacity by 2030 is expected to entail reductions of CO_2 emission between 2.5 million tonnes and 4.0 million tonnes. The subsidy scheme, based on a tender process in respect of a fixed price surcharge, is expected to be launched in 2023, subject to its approval by the EU Commission.

The conditions for eligibility of support for each scheme launched are published by the DEA. Draft conditions for the competitive bidding process for Power-to-X can be found at the website of the DEA.

F.3 Biofuel

Bioenergy is the most widely used RES in Denmark and subject to the regulation by the DEA There are currently some 150-200 installations in use which are subject to the original price supplement scheme. New installations (post 2020) seeking state aid will have to await the implementation of a new tender scheme for biogas and e-methane. These new schemes have an expected launch date with the first round of a total of 6 tender rounds taking place sometime in 2023. A provisional draft of the tender conditions can be found at the website of the DEA.

G. Climate change and sustainability

G.1 Climate change initiatives

At the COP26 meeting in Glasgow in 2021, Denmark came out on top in the Climate Change Performance Index (CCPI) in which 60 countries with a combined GHG emission of more than 90% participated. With the adoption of the 2020 Climate Act, Denmark committed to a 2030 target of a 70% emissions reduction compared with 1990 levels and aims for climate neutrality by 2050.

Pursuant to the 2021 climate action plan published by the government, all significant decisions required to attain the 2030 target must be taken by 2025. In its roadmap, the government has identified the following focus areas with regard to which initiatives will be launched during the period up to 2025:

- Green energy sector: Agreement on carbon capture strategy/policy reached the end of 2021 with DKK14 billion in public grants set aside. 2022 will see new proposals to realise the energy sector's climate potential which involves a follow-up on the 2018 political agreement;
- Green industry sector: Carbon Capture and Storage ("CCS") agreement, electrification of processes, including local transport, conversion to PtX/biofuels etc;
- Green waste disposal sector: Reduction of waste incineration and focus on re-use;
- Green agriculture: Green transition, combination of development of green technologies and tax reforms;
- Green cars: Ongoing with the focus on heavy road haulage. The Danish Climate Council has concluded that heavy trucks will be fuelled by either hydrogen or electricity (and dismisses biogas); and
- Green fuels: In December 2021 the government launched its proposal for development of PtX and production of green hydrogen, setting aside funds for large scale demonstration projects.

G.2 Emissions trading

The Danish CO_2 Allowances Act (of 2021) (*lov om CO_2 kvoter*) and an earlier executive order of 2020 regulate the Danish emissions scheme (CO_2 gases and other emissions). The DEA is the regulatory body in charge.

Emissions require a permit issued to the operator of the installation requiring the operator to monitor and report emissions (pursuant to an approved emissions' monitoring plan). Operators subject to EU allowances regulations will each year, by 30 April, surrender and register with the EU Emission Register allowances corresponding to measured emissions.

Allowances are either granted, on application, to operators for free (on the basis of benchmark values prepared by the EU-commission, the 'ALC values') or acquired via auction via the EU Emissions Trading System ("EU ETS").

Allowances are financial instruments and can be traded provided those wishing to trade have an account in the Danish EU ETS Registry.

G.3 Carbon pricing

An expert group for 'the green tax reform' commissioned with the task to examine how GHGs can be reduced based on higher and more uniform carbon taxation delivered the first part of its report in February 2022. The basis for the report is the GHG reduction gap between the Danish intermediate 2025 GHG reduction goal of 50%–54% and what is considered realistic given current, agreed initiatives. The report's conclusions and recommendations will now form part of upcoming political discussions.

G. 4 Capacity markets

A result of Denmark's high degree of energy interconnectivity is that there is no official policy with regard to a Danish capacity market and currently no signs that one will be developed.

H. Energy transition

H.1 Overview

See sections A to G, H and I.

H.2 Renewable fuels

The PtX technology, which includes the production of green hydrogen, ammonia, methanol, and green jet fuel, has been embraced by the government as a possible means to attain Denmark's climate objectives, particularly for 2050, by transitioning parts of the transport sector with emphasis on road haulage, transport by air and sea, agriculture, and the industry. Initial funds have been set aside for large scale demonstration projects in fields such as PtX.

H.3 Carbon capture and storage

Two draft bills related to CCS were submitted for public hearing in November and December 2021 and were expected to be brought forward in the Danish parliament during February 2022. The first draft Bill relates mainly to geological storage of CO_2 of less than 100 kilotons and the second relates to the possibility for state participation in CO_2 storage licences. Both draft Bills are a part of the Danish government's plans to clarify the legal framework for CCS in Denmark, and a part of the Danish government's strategy to enable full-scale CCS in Denmark from 2025 onwards, with the first licences for storage to be granted before the end of 2022.

H.4 Oil and gas platform electrification

As part of the 2020 North Sea political agreement to discontinue further licensing rounds and set an end date for oil and gas production, the political parties agreed to engage the sector in discussions and analysis of the possibilities for electrification of the existing offshore infrastructure to reduce emissions. About DKK5 million was set aside for this work which is still ongoing.

H.5 Industrial hubs

There are several industrial hubs/clusters in Denmark bridging commerce/industry and science. Of relevance are particularly two clusters, Energy Cluster Denmark (energy technology) and CLEAN (environmental technology)[11]. These are membership driven non-profit associations offering members an innovation platform for establishing and facilitating innovation collaborations between small and large companies, knowledge institutions, and public players in the relevant sector.

H.6 Smart cities

Danish cities are investing substantially in intelligent lighting and transport systems, climate adaption, energy renovation and retrofitting, smart grid technology, and digitalisation of social and health care services. There is no single, official definition in Denmark of what constitutes a smart city. Rather it is about the extent to which municipalities will deploy funds to commission smart city projects that are meaningful in terms of meeting local requirements. There is no legislative framework particular to smart cities.

I. Environmental, social and governance (ESG)

The Danish institutional investment scene is dominated by the various pension funds with over DKK4,400 billion of funds under management.

In a recent statement, the Danish public pension fund ATP announced that the pensions giant aims towards DKK200 billion in green investments by 2030 and DKK100 billion by 2025, adding 'we simply cannot afford not to'. This will make ATP Denmark's potentially largest green investor. ATP will also make demands on the companies in which ATP invests to report on their discharge of CO_2 in that it must be measurable to the extent to which companies put strain on the climate. In this way ATP's climate footprints from the portfolio will achieve its target of a CO_2-neutrality in 2050 and 70% reduction in 2030.

A similar investment pattern/policy is pursued by the other private Danish pension funds and, perhaps to a lesser degree, by the private commercial investment fund segment managed by professional fund managers, such as banks.

A not surprising result is that commercial market investments in traditional hydrocarbon extraction industries have become almost extinct. A similar trend is observed within the financing/commercial lending market.

Endnotes

1. Act No. 965 of 26 June 2020, as later amended.
2. Statutory order No. 984 of 5 December 2021.
3. Statutory order No. 1533 of 16 December 2019, as later amended.
4. Statutory order No. 126 of 6 February 2020, as later amended.
5. See www.en.energinet.dk/media/smmeikmi/general-terms-and-conditions-for-gas-transportversion-222englishlegally-binding.pdf.
6. A Direct Consumer is any given natural or legal person who supplies and consumes Natural Gas from the Transmission System at direct sites. A direct site is the actual point at which the Gas Metering System is physically located and to which the Natural Gas is supplied/redelivered to the Consumer from the Transmission System.
7. See www.gasstorage.dk/Rules.
8. See www.energinet.dk/El/Elmarkedet/Regler-for-elmarkedet/Markedsforskrifter#C1.
9. Statutory order No. 1791 of 2 September 2021 as later amended.
10. Has been used through executive order of 5 June 2021 introducing one single point of contact and one single two-year application processing deadline.
11. See www.energycluster.dk/and www.cleancluster.dk.

Energy law in Estonia

Recent developments in the Estonian energy market

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Shift from electricity exporting country to importing country

After the decommissioning of the Ignalina NPP in Lithuania in 2009 Estonia has been the main electricity producer and exporter in the Baltic States. This has changed drastically as the main generation capacities in Estonia are based on oil shale and production of electricity from oil shale is no longer competitive on account of it being CO_2 intensive.[1]

In 2019, 6,447GWh of electricity was generated in Estonia (representing a significant decrease as compared to 2018 when 10,583GWh of electricity was generated). Annual consumption is around 8,000GWh and therefore Estonia has become an importer of electricity.[2]

In 2021 around 1GW of existing oil shale-based generation capacity was planned to be closed by state-owned Eesti Energia AS. Based on guidelines issued by the Ministry of Finance that exercises shareholder rights in the company, Eesti Energia AS will ensure 1GW of controllable production capacity in its portfolio at least until end of 2023.[3]

Top priorities for Estonia for the coming years are further connection of its energy systems with the EU grid and the development of new generation capacity with a focus on renewable energy.

Synchronisation of the Baltic States' electricity grid with the ECN

For historical reasons the electricity grid of the Baltic States continues to be operated in a synchronous mode with the Russian and Belarusian systems.

Formerly an energy island, the Baltic States region is now connected with other EU Member States through several electricity lines. These are the LitPol Link between Lithuania and Poland, the NordBalt interconnector between Lithuania and Sweden, and Estlink 1 and Estlink 2 interconnectors between Estonia and Finland. As a result of the increased connections of the electricity systems of the Baltic States with the EU grid various alternatives for the desynchronisation of the electricity systems of the Baltic States from the IPS/UPS and synchronisation with the ECN have been explored.

In June 2019 the President of the European Commission and the heads of state of Estonia, Latvia, Lithuania and Poland signed the political roadmap implementing the synchronisation of the Baltic States' electricity networks with the ECN via Poland, the target date for the full synchronisation being 2025.[4]

Replacing FIP based renewable energy support scheme with CfD

In 2018, granting of renewable energy support in the form of fixed feed-in premium ("FIP") was replaced with the system of auctions where the winner is the producer offering the lowest Contract for Difference ("CfD"). Based on the results of the auction the winning producer will have the right to cover the difference between the monthly market price and the price established at auction in the production volume offered in the auction in the form of return of negative balance. The CfD as applied in Estonia means that producers are not obliged to return the surplus if the market price exceeds the auction price. No support is allocated when the electricity price on the power exchange is lower than or equal to zero.

Under the new system, new generation installations can receive support only when Estonia needs additional renewable energy capacities in order to meet the target for the share of electricity generated from renewable energy sources. The target for 2020 was set at 17.6%. According to a draft act discussed at Parliament in July 2021, the target for 2030 was proposed to be set at 40%.

As a rule, only companies registered in Estonia are allowed to participate in auctions. Additionally, companies registered in European Economic Area may participate in auctions, but only in case the country of their incorporation permits companies registered in Estonia to participate in similar auctions held in that country. Companies can participate in auctions with generation installations which commence production for the first time only after the results of the auction have been announced in order to ensure the incentive effect of the state aid. According to a draft act discussed at Parliament in July 2021, it was proposed to allow existing cogeneration plants using biomass to participate in auctions under certain limited cases in order to achieve the target for the share of electricity generated from renewable energy sources.

As of 2019, auctions have been held annually for small volumes (5GWh) in preparation for an auction for 450GWh that is expected to be announced by the end of 2021 and an auction for 650GWh that is expected to be announced in 2023.[5]

*The market and regulatory developments discussed here are as of July 2021.

The previous support scheme in the form of fixed FIP remains in place with regards to existing producers, ie producers who commenced works on the investment project and took irreversible commitments by 31 December 2016. Longer transitional periods applied with regards to generation installations with electrical capacity of less than 1MW, the last transitional period applicable to generation installations with electrical capacity of less than 50kW expired at the end of 2020 and all new developments have to be undertaken against the market, unless support is obtained by participating at auctions.

Emergence of a new regional gas market

2020 brought a number of major changes to the Estonian gas market.

The Balticconnector, the interconnector between Estonia and Finland, started operations. Although the full capacity of the Balticconnector is not yet available due to delays in completion of some of construction works, it has enabled creation of a common market area of Finland, Estonia, and Latvia ("FinEstLat"). FinEstLat is a unique setup where there are no tariff restrictions on the movement of gas within a region of three countries, and a common entry tariff for the market area is applied. The FinEstLat common market area does not include Lithuania as no agreement was reached with the Lithuanian Transmission System Operator ("TSO") on cost compensation.

A common Estonian-Latvian balance area was also launched with common standard terms and conditions, allowing market participants to trade in the area by concluding an agreement with just one TSO. The advantage of a common balancing area is that the imbalance is calculated on regional basis instead of country basis, which should lead to savings in balancing costs.

The Balticconnector connects the gas transmission networks of the Baltic States and Finland, and provides Finland with access to the Inčulkans gas storage facility located in Latvia. After the commissioning of the Lithuanian-Polish interconnector (GIPL) the Baltic States and Finland will have access to the European gas network, improving regional security of supply and creating a positive environment for the development of a functioning regional gas market.

Endnotes

1. Report on Electricity and Gas Markets in Estonia, 2019-2020, pp 57-58. Available at www.konkurentsiamet.ee/sites/default/files/euroopa_aruanne-loplik_tolge_en_140421_.pdf.
2. Report on Electricity and Gas Markets in Estonia, 2019-2020, p.6.
3. Report on Electricity and Gas Markets in Estonia, 2019-2020, p.61.
4. See European Commission 20 June 2019 press release for an overview of the matter and related documentation, available at https://ec.europa.eu/commission/presscorner/detail/en/IP_19_3337.
5. Ministry of Economic Affairs and Communications, see www.mkm.ee/et/tegevused-eesmargid/energeetika/taastuvenergia.

Overview of the legal and regulatory framework in Estonia

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Estonia has been fully liberalised since January 2013 and all customers are required to purchase electricity on the open market.

Key market players

The transmission system network is owned and operated by state-owned Elering AS, the Estonian Transmission System Operator ("TSO"). The shareholder rights of Elering AS are executed by the Ministry of Economic Affairs and Communications.

State-owned Eesti Energia AS, a vertically integrated undertaking with its own oil shale mining operations, generation units and energy trading and sales units, is the main market player. The shareholder rights of Eesti Energia AS are executed by the Ministry of Finance. Eesti Energia AS also owns all of the shares in Elektrilevi OÜ, the main Distribution System Operator ("DSO") in Estonia whose sales constitute 86.3% of the total sales of network services[1], as well as all the shares in Enefit Power AS, a company which uses oil shale to generate 3/4 of Estonia's electricity[2]. Eesti Energia AS as the incumbent supplier of electricity has retained 60.9% market share followed by Elektrum Eesti OÜ with 10.9% market share and Scener OÜ with 8.3% market share.[3]

Regulatory authorities

The Ministry of Economic Affairs and Communications has overall responsibility for the energy sector, however, the Estonian Competition Authority ("ECA") acts as the regulatory body. The functions of the ECA and the Ministry of Economic Affairs and Communications have been clearly separated by legislation.

The ECA oversees both the electricity and gas markets. Its main duties in relation to the electricity sector include:

- issuing licences, including certification of the TSO;
- overseeing the prices set for the supply of electricity under the universal service concept and the prices charged by the TSO and the DSOs (or in some cases, the method used to calculate prices); and
- approval of standard terms and conditions of balancing agreements, network service agreements and agreements for the supply of electricity under the universal service concept.

Legal framework

The legal framework of the electricity market in Estonia is set out in the Electricity Market Act ("EMA") and network codes adopted thereunder.

In addition to contracts between the system operator and the balance operators (companies that have entered into a balance agreement with the system operator), contracts are entered into between market participants, including connection, network and electricity supply contracts. Each market participant is also required to have an open supply contract, which enables balancing to take place.

Implementation of EU electricity directives

The EU electricity directives have been fully implemented, except for the amendments stipulated in the recast Electricity Directive.

Significant industry issues

After the decommissioning of the Ignalina NPP in Lithuania in 2009 Estonia has been the main electricity producer and exporter in the Baltic States. This has changed drastically as the main generation capacities in Estonia are based on oil shale, and production of electricity from oil shale is CO_2 intensive.[4]

In 2021 around 1GW of existing oil shale-based generation capacity was planned to be closed by state-owned Eesti Energia AS. Based on guidelines issued by the Ministry of Finance that exercises shareholder rights in the company, Eesti Energia AS will ensure 1GW of controllable production capacity in its portfolio at least until end of 2023.[5]

Top priorities for Estonia for the coming years are further connection of its energy systems with the EU grid and the development of new generation capacity with a focus on renewable energy.

A.2 Third party access regime

Within its service area, a network operator must connect compliant electrical installations to its network, to enable use of network connections and transport electricity through its network. There are limited grounds set out in the EMA that allow a network operator to refuse to connect an installation to its network or to refuse to provide other network services (eg non-compliant electrical installations or lack of sufficient capacity).

A network operator providing network services is entitled to levy charges for connection to its network (and for any changes in the load), for the provision of network services and for any other services directly related to network services.

A.3 Market design

As a rule, electricity undertakings must be companies registered in the European Economic Area ("EEA"). See section A.5 for further details on capital requirements and the licensing regime.

The full ownership unbundling ("FOU") of the Estonian TSO, Elering AS, was completed in January 2010. As of April 2010, Estonia is part of Nord Pool Spot power exchange.

A.4 Tariff regulation

A network operator providing network services is entitled to levy charges for connection to its network (and for any changes in the load), for the provision of network services and for any other services directly related to network services.

Different network operators may have different network charges. Within a network operator's service area, the fees charged may not vary based on a market participant's location. Network operators may divide market participants into groups and apply different network charges to such groups, eg based on the electrical voltage of the installation connected to the network.

The ECA approves the fee that the network operators may charge for the provision of network services, applying ex-ante price control. The charges must enable the network operator to perform the obligations required of it by law and under the terms of its licence. Charges must also ensure that a reasonable profit margin on invested capital is secured.

Network operators set the charges for connection and changes in the load. These charges must be calculated in accordance with the pricing methodology approved by the ECA.

A.5 Market entry

As a rule, electricity undertakings must be limited liability companies established and registered in the EEA. Minimum capital requirements set out in the EMA also apply. Additionally, a company must have a licence or a notice of economic activities to operate as an electricity undertaking.

Licences are required for the generation of electricity, provision of transmission services, provision of distribution services, conveying electricity through a direct current line crossing the national border and conveying electricity through a direct line. Certain exceptions to the licensing requirements apply, eg a licence is not required for the generation of electricity with a generating installation with a total net capacity of less than 200kW.

The licence to provide transmission network services in Estonia is granted to one network operator, the TSO. When a licence is issued to a DSO, the ECA ensures that no parallel networks are built in that same licence area.

As of January 2019, the sale of electricity no longer requires a licence and instead a notice of economic activities must be submitted to the ECA. There are also certain exceptions to the requirement to submit a notice of economic activities, eg notice is not required when selling electricity on the power exchange.

Licences are granted by the ECA and are issued without a term. The ECA may revoke licences for various reasons, including where a licence-holder is acting in breach of its licence conditions or is no longer fulfilling the prerequisites and conditions set out in the EMA.

No licence is required to import electricity, but electricity may only be imported by the system operator or by the exchange participants (market participants who have concluded a respective contract with the exchange) for sale on the Nord Pool Spot power exchange. The import of electricity is defined in the EMA as the importation of electricity from outside the EEA for the purposes of selling or consuming that electricity in Estonia.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Small-scale consumers (households and business customers whose electricity installations are connected to the network at low voltage) can buy electricity under the universal service concept. If they have not chosen an electricity supplier, the network operator to whose network the consumer's installations are connected to shall either sell the electricity itself or appoint a supplier who will provide this as a universal service. The price of electricity sold under the universal service concept is the weighted average price calculated based on the hourly consumption of electricity during any month and the hourly prices of the electricity exchange during such month. A reasonable sales margin will be added to such weighted average price.

Smart metering

Under the network code on the functioning of the electricity system, all standard electricity meters in Estonia had to be replaced with remote-readable meters by the end of 2016.

Electric vehicles

Estonia was the first country in the world to construct a country wide charging network of electric cars in 2012. A support system was also in place for acquisition of electric cars together with other supportive measures such as free parking for electric cars. The charging network was established in cooperation with Mitsubishi Corporation using the proceeds from the sale of excess GHG emission allowances.

A.7 Cross-border interconnectors

Historically, the electricity systems of the Baltic States were isolated from the main European grid and were instead directly connected to the Russian transmission grid. As a result of the substantial investments made to connect the electricity system of the Baltic States with the EU grid, this is no longer the case.

There are two EstLink interconnectors between Estonia and Finland with a combined capacity of 1,000MW, the LitPol interconnector between Lithuania and Poland with the capacity of 500MW, and the NordBalt interconnector between Lithuania and Sweden with the capacity of 700MW. A third interconnector between Estonia and Latvia became operational in 2021 and increased the initial 900MW capacity of interconnectors between Estonia and Latvia by a further 600MW.

The electricity systems of the Baltic States currently remain synchronised with IPS/UPS of the Commonwealth of Independent States. In June 2019 the President of the European Commission and the heads of state of Estonia, Latvia, Lithuania and Poland signed the political roadmap implementing the synchronisation of the Baltic States' electricity networks with the European Continental Network via Poland, the target date for the full synchronisation being 2025.[6]

B. Oil and gas

B.1 Industry structure

Nature of the market

The gas market is fully liberalised. Under the Natural Gas Act ("NGA"), from July 2007 all customers have had the right to choose their gas supplier. However, in practical terms there was no real choice for the customers as all the gas was imported by the dominant supplier AS Eesti Gaas from Russia and all other gas suppliers acquired gas for re-sale from AS Eesti Gaas. The nature of the market has been changing since 2015 as a result of the completion of the FOU model of the TSO, and the emergence of additional sources of supply and new market participants.

Finland, Estonia and Latvia have agreed on the common gas market terms, and the new cross-border gas market FinEstLat commenced operations as of January 2020.

Key market players

As of January 2015, the TSO is state-owned Elering AS.

AS Eesti Gaas remains the principal gas importer with a market share of 84% and the largest supplier with a market share of 62%, followed by JSC Latvias Gaze with 17% market share, Eesti Energia AS with 12.4% market share and Alexela AS with 6.9% market share.[7] AS Eesti Gaas also owns all the shares of AS Gaasivõrk, the largest DSO in Estonia.

Regulatory authorities

As in the case of the electricity market the functions of the regulator are carried out by the ECA. The Ministry of Economic Affairs and Communications has overall responsibility for the energy sector.

The ECA's main duties regarding the gas sector include:

- issuance of licences, including certification of the TSO;
- approval and supervision of prices (or in some cases, the method used to calculate prices); and
- approval of standard terms and conditions of balancing agreements, network service agreements and agreements for the sale of gas to household customers.

Legal framework

The main legislation setting out the framework of the Estonian gas market is the NGA and the gas market network code. The gas market network code sets out more detailed technical requirements regarding balancing, change of supplier, exchange of data between the market participants and quality of gas.

In addition to contracts between the system operator and the balance operators (companies that have entered into a balance agreement with the system operator), contracts are entered into between market participants, including connection, network and gas supply contracts. Each market participant is also required to have an open supply contract, which enables balancing to take place.

Implementation of EU gas directives

The Third Gas Directive has been fully implemented.

B.2 Third party access regime to gas transportation networks

Within the technical limits of the network, a network operator is required to provide a network connection to all persons located within its network area who apply for a connection, provided it does not endanger the security of supply to those customers who are already connected.

A network operator is entitled to levy charges for connection to the network and for the provision of network services.

B.3 LNG terminals and storage facilities

As of December 2021, no LNG terminals or gas storage facilities in Estonia, although two LNG projects (Paldiski LNG developed by Alexela AS and Tallinn LNG developed by AS Liwathon E.O.S.) are in the early development phase.

B.4 Tariff regulation

As of commencement of operations of the cross-border gas market FinEstLat, the tariff model applied to transmission services was changed significantly. The tariffs for intra-system network use and entry-exit pricing for the cross-system network use are approved by the ECA ex-ante. Price cap regime is applied for fixed payable transmission prices and postage stamp reference price method for domestic transmission prices. Entry pricing has been harmonised with the neighbouring states (based on a benchmark study of an EU average plus an error margin), when calculating reference prices interconnection points within FinEstLat have been eliminated, minimising the compensations between the TSOs via exit tariffs of each participating country.[8]

Network operators set the charges for connection. These charges must be calculated in accordance with a pricing methodology that has been approved by the ECA.

B.5 Market entry

Companies must have the required technical capabilities and personnel to participate on the gas market. The NGA also sets out minimum capital requirements which apply to entities wishing to participate on the market.

Licences are required for the importation of gas, provision of transmission services and distribution services, operation of an LNG terminal and provision of gas storage services. Since July 2017, the sale of gas no longer requires a licence and instead a notice of economic activities must be submitted to the ECA.

Licences are granted by the ECA and are issued without a term. The ECA may revoke licences for various reasons, including where a licence-holder is acting in breach of its licence conditions or is no longer fulfilling the prerequisites and conditions set out in the NGA.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The gas supplier that has the largest market share within a network area must sell gas within the technical limits of the network to any household customer that has a network connection and is located within the network area.

Smart metering

All network operators had to ensure that by the beginning of 2020 all measurement points through which at least 750 cubic metres of gas per annum is consumed are equipped with remote-readable meters that also take into account temperature of the gas in the measurement system.

B.7 Cross-border interconnectors

Historically Estonia only had interconnectors with Latvia and Russia, and as of 2020 also has an interconnector with Finland.

C. Energy trading

C.1 Electricity trading

Electricity trading takes place on the Nord Pool power exchange and to a limited extent through over the counter ("OTC") arrangements. In Estonia, Nord Pool power exchange offers day-ahead trading (Elspot) and intraday trading (Elbas). Trading is both physical and financial. ISDAs/EFETs are used.

Estonia participates in EU Market Coupling via the Price Coupling of Regions ("PCR") project which aims to achieve the goal of a harmonised European electricity market by developing a single price coupling solution to be used to calculate electricity prices across Europe, respecting the capacity of the relevant network elements on a day-ahead basis.[9] Estonia participates in the PCR project via Nord Pool.[10]

The system operator and balance operators execute balancing agreements in the form of open supply contracts. The system operator sells or buys the amount of electricity necessary in order to balance the balance operators' portfolios in each trading period. Each market participant must have an open supply contract with a supplier and, if that supplier is not a balance operator, the supplier must have either an open supply contract with a balance operator or be connected to the balance operator through an uninterrupted chain of open supplies. Market participants may also have fixed supply contracts that set out a specific volume which is sold/purchased.

C.2 Gas trading

Gas trading takes place through OTC arrangements or on the GET Baltic natural gas exchange. Trading is both physical and financial. GET Baltic natural gas exchange administrates the electronic trading system for trading spot and forward natural gas products with physical delivery in the market areas located in Lithuania, Latvia, Estonia and Finland.[11] Within the GET Baltic natural gas exchange Estonia and Latvia are considered to be a common market area.[12]

D. Nuclear energy

No nuclear energy is currently generated in Estonia. Under the EMA, the establishment of a nuclear energy project in Estonia requires authorisation from the Parliament.

Since 2019 Fermi Energia OÜ has been exploring the possibility of introducing a new generation small modular reactor in Estonia. In 2021 a nuclear energy working group was created, bringing together representatives from most ministries, to explore the possibility of establishing a nuclear energy project in Estonia.

Estonia has been a member state of the International Atomic Energy Agency since 1992.

E. Upstream

There are no conventional gas and oil resources in Estonia.

F. Renewable energy

F.1 Renewable energy

The state has put in place a subsidy scheme to support the development of renewable energy capacities in order to contribute to the achievement of the target for the share of electricity generated from renewable energy sources.

The support scheme differentiates between existing producers and new producers. The existing producers are entitled to receive a fixed feed-in premium ("FIP") as described below, whereas new producers can receive support only when Estonia needs additional renewable energy capacities in order to meet the target for the share of electricity generated from renewable energy sources and arranges auctions for the development of new electricity generation installations.

A producer generating electricity in a generation installation with electrical capacity of more than 1MW who commenced works on the investment project and took irreversible commitments by 31 December 2016 is treated as an existing producer and therefore qualifies for the fixed FIP support scheme. For generation installations with electrical capacity of 1MW or less, the producer is treated as an existing producer in case the generation installation was generating electricity: (i) by 31 December 2018, in case of generation installations with electrical capacity between 50kW to 1MW; or (ii) by 31 December 2020, in case of generation installations with electrical capacity of less than 50kW.

An existing producer is entitled to receive support in the form of FIP from the TSO for each kWh of electricity generated: (i) from a renewable energy source with a generation installation the net capacity of which does not exceed 125MW at the rate of €0.0537/kWh; (ii) from biomass in a cogeneration plant at the rate of €0.0537/kWh; (iii) from waste, peat or retort gas in an efficient cogeneration plant at the rate of €0.032/kWh; or (iv) in an efficient cogeneration plant the net capacity of which does not exceed 10MW at the rate of €0.032/kWh. Only electricity supplied to the network or to a customer via a direct line qualifies for the support, ie the generation installation's own consumption is not subsidised. The support is paid by the TSO in addition to the price received by the producer upon sale of the electricity. The support is paid for a period of 12 years following commencement of production. Certain restrictions apply, eg in the case of wind energy, a cap of 600GWh per calendar year applies to wind energy producers qualified to receive the FIP; facilities using biomass will qualify for the subsidy only if they use cogeneration processes and not if they use condensation processes.

In 2018, granting of renewable energy support in the form of FIP was replaced with the system of auctions where the winner is the producer offering the lowest contract of difference. Based on the results of the auction the winning producer will have the right to cover the difference between the monthly market price and the price established at auction in the production volume offered in the auction in the form of return of negative balance. The Contract for Difference (CfD) as applied in Estonia means that producers are not obliged to return the surplus if the market price exceeds the auction price. No support is allocated when the electricity price on the power exchange is lower than or equal to zero.

Under the new system, new generation installations can receive support only when Estonia needs additional renewable energy capacities in order to meet the target for the share of electricity generated from renewable energy sources. The target for 2020 was set at 17.6%. According to a draft act currently discussed at Parliament in July 2021, the target for 2030 was proposed to be set at 40%.

The TSO issues certificates of origin, which certify that the electricity is generated from renewable energy sources or in an efficient co-generation process. The certificates or origin can be traded on the market separately from electricity.

F.2 Renewable pre-qualifications

As a rule, only companies registered in Estonia are allowed to participate in auctions. Additionally, companies registered in EEA may participate in auctions, but only in case the country of their incorporation permits companies registered in Estonia to participate in similar auctions held in that country.

Companies can participate in auctions with generation installations which commence production for the first time only after the results of the auction have been announced in order to ensure the incentive effect of the state aid. According to a draft act discussed at Parliament in July 2021, it was proposed to allow existing co-generation plants using biomass to participate in auctions under certain limited cases in order to achieve the target for the share of electricity generated from renewable energy sources.

F.3 Biofuel

The state has put in place a subsidy scheme to support the production of biomethane in order to contribute to the achievement of the target for the share of renewable fuels consumed in the transport sector.

The subsidy is available for producers of biomethane which meets the established sustainability criteria and which is produced in a generation installation the net installed capacity of which does not exceed 50,000 tonnes per annum. Certain exceptions also apply, eg food-based biofuels and installations which have fully amortised are excluded from the subsidy scheme.

The subsidy is paid upon supply of biomethane to end users. The supply of biomethane to end users must be certified by a certificate of origin issued by the TSO. Certificates of origin may be used within 12 months following the production of the corresponding energy unit (MWh).

The subsidy is in the form of compensation of eligible costs up to a certain level. Eligible costs are the cost of production of biomethane which has been supplied as transport fuel to end users (per MWh), or the cost of production of biomethane which has been supplied to end users through the gas networks. In the latter case the network fees do not qualify as eligible costs. Also, any investment support received must be deducted from the cost of production.

The subsidy is available with regards to eligible costs incurred during the period starting from 2018 through to 2023 or until availability of state funds allocated to the biomethane subsidy. The subsidy is financed from the funds received by the State upon the sale of excess EU allowances (EUA).

For biomethane supplied as transport fuel the eligible costs are compensated up to the amount equal to the sum of €100/MWh minus the average market price of natural gas for the ongoing month. For biomethane supplied through gas networks the eligible costs are compensated up to the amount equal to the sum of €93/MWh minus the average market price of natural gas for the ongoing month. The average market price of natural gas for the ongoing month is the weighted average price of natural gas published by the combined natural gas exchange operator of the Baltic States during each month of production of biomethane based on the sale and purchase transactions which took place in the bid areas of the Baltic States. If in any month the total volume of transactions is below 500MWh, the average market price of natural gas for the respective month is €20/MWh. The subsidy per energy unit may not exceed the difference of the levelised cost of the produced energy and the market price of the same type of energy.

G. Climate change and sustainability

G.1 Climate change initiatives

In 2019, 6,447GWh of electricity was generated in Estonia (representing a significant decrease as compared to 2018 when 10,583GWh of electricity was generated). Annual consumption is around 8,000GWh and therefore Estonia has become an importer of electricity.[13]

As at January 2020, the installed net capacity of the generation installations located in Estonia was 3,041MW, including 329MW of wind parks, 128MW of solar power parks and 8MW of hydro power plants.[14] Main production capacities in Estonia are based on oil shale and are being phased out.

According to the national energy and climate plan (NECP 2030) of Estonia[15], the share of renewable energy in total final consumption should reach 42% by 2030, from 1.9TWh in 2020 to 4.5TWh in 2030.

G.2 Emission trading

Estonia applies the EU ETS and has no additional national schemes.

G.3 Carbon pricing

Estonia applies the EU ETS and has no country specific carbon pricing strategy.

G.4 Capacity markets

Estonia has not introduced any legislative or regulatory regimes relating to capacity markets.

H. Energy transition

H.1 Overview

Under Estonia's NECP 2030, the key objectives include:

- 80% reduction in GHG emissions by 2050 (70% by 2030);
- 42% share of renewable energy in total final consumption by 2030, whereas in 2030 final energy consumption must remain at 32-33TWh; and
- energy security must be ensured via reducing dependency on

energy imports, whereas the power grid must be synchronised with ECN by 2025.[16]

Estonia's National Energy and Climate Plan 2030 also sets out a target to increase renewable energy production from 1.9TWh in 2020 to 4.5TWh in 2030, with main focus on wind energy (expected increase from 670GWh to 2,640GWh).[17]

H.2 Renewable fuels

Hydrogen

Estonia joined the Hydrogen Initiative at the informal meeting of EU energy ministers held in September 2018[18], however, to date, no national strategy or legislative framework on use of hydrogen has been prepared.

Ammonia

Estonia has not introduced any national strategy or legislative framework on use of ammonia.

H.3 Carbon capture and storage

As of December 2021, there are no CCS projects in Estonia. The Ministry of Environment has stated that such projects are unlikely to be initiated in the foreseeable future as Estonia does not have suitable geological conditions for such projects. Additional research is being carried on the possibilities of mineral trapping of CO_2 with oil shale ash.[19]

H.4 Oil and gas platform electrification

There are no conventional gas and oil resources in Estonia.

H.5 Industrial hubs

There are several industrial parks with predeveloped infrastructure welcoming manufacturing and logistics companies.[20] Ülemiste city area in Tallinn, the capital of Estonia, has been a hub for innovative tech companies and a booming community for developing various smart technologies.[21]

H.6 Smart cities

Estonia applies smart city concepts in mobility (Estonia was the first country in the world to implement smart parking; in 2017 Estonia legalised the testing of autonomous vehicles) and life quality (lead in telematics as emergency services can accurately pinpoint callers in seconds; digitally enabled infrastructure; Big Data analytics implemented for urban planning, civil safety and tourism). Smart Port and FINEST Twins joint ventures with Finland increase interoperability between neighbouring Tallinn and Helsinki.[22] Tallinn University of Technology with its Smart City Centre of Excellence department is leading the way with specialised programmes nurtured for innovation and the development of smart cities, pooling funding also from the EU Horizon 2020.

I. Environmental, social and governance (ESG)

Both global and local financial institutions and institutional investors, including Baltic pension funds, are putting increasingly important emphasis to ESG factors in their investment and financing processes. As a result it has become increasingly difficult to secure financing for fossil fuel energy projects which in turn supports transition to renewable energy.

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Energy law in Finland

Recent developments in the Finnish energy market

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Changes to the legal framework

Reform of the Land Use and Building Act

The Land Use and Building Act[1] concerns the use of land and building activities conducted on land. Currently, the Land Use and Building Act is under comprehensive reform. The government proposal of the Land Use and Building Act was passed and approved by the Finnish Government on 15 September 2022. The aim is that the new legislation would enter into force on 1 January 2024.[2]

The main objectives of the reform are to promote a carbon-neutral society, strengthen biodiversity, improve the quality of construction, and advance digitalisation. The aim of these objectives is to meet the needs of modern social phenomena such as climate change, regional structure differentiation, urbanisation, transition to clean energy, and sustainable development. The reform must also ensure legislation is compatible with EU legislation. The new Land Use and Building Act will include more specific rules on, for example, the energy efficiency of buildings, the use of smart technology in buildings, and the charging capacity of electric vehicles.[3]

Government proposal for an additional profit tax for electricity companies and companies in fossil fuel sector

The Finnish Government has given a government proposal regarding an additional 30% profit tax for electricity companies and additional 33% profit tax for companies in the fossil fuel sector. The profit tax is intended to be non-current, ie, it will only cover profits gained during the tax year 2023. The government proposal is currently being handled in the Finnish Parliament as an urgent matter and is intended to come into effect as soon as possible.

The government proposal is based on the regulation of the European Council on emergency intervention to address high energy prices (EU 2022/1854) and the Government's budget negotiations in autumn 2022. The proposal aims to address the significantly high returns generated by exceptionally high prices for certain companies in the energy market, which do not result from the companies' own additional contributions or investments, and to redistribute those returns in favour of consumers suffering from high energy prices.

The additional profit tax would be applicable to enterprises producing and/or selling electricity and enterprises in the fossil fuel sector. Companies that are engaged in minor electricity business (ie, companies whose electricity business turnover is less than EUR 500,000 per year or whose electricity business comprises less than 10 percent of its total turnover) would be outside the scope of the new legislation. There are also other enterprises to which the additional profit tax does not apply, eg TSOs and DSOs.

The additional profit tax would be paid in addition to the standard corporate income tax of 20%. For companies in the electricity sector, the taxable base would be the electricity business' net profit, which exceeds a ten percent (10%) annual return on the amount of shareholder's equity recorded in the electricity business' pro forma balance sheet of the previous year. In the case of companies in the fossil fuel sector, the taxable base would be the result which exceeds 120 percent of the average and yearly business income stemming from tax years 2018-2021. If the company hasn't had business activity in those years or the yearly average is negative, the comparable amount for the tax base is set to be zero.[4]

Climate change initiatives and developments

The current Government of Finland set carbon neutrality in Finland by 2035 as a key target in its government program in 2019.[5] This target has now been laid down in law for the first time in the reformed Climate Change Act[6], which also sets emission reduction targets for 2030, 2040, and 2050. The Climate Change Act requires Finnish ministries to draw up four climate change policy plans, namely the Medium-term Climate Change Policy Plan, the National Climate Change Adaptation Plan, the Long-term Climate Change Policy Plan, and the Climate Change Plan for the Land Use Sector. The Climate Change Act only applies to public authorities, not companies or individuals. The Government will monitor whether climate targets have been met and decide whether further measures are necessary to achieve them.[7]

The Government has also prepared a separate climate and energy strategy, which it submitted to the Parliament in June 2022. The strategy is a comprehensive action plan for the medium term, which Finland will implement to meet the EU's obligations for 2030 and to achieve the national climate target for 2035. The strategy focuses on the green transition and the phasing-out of Russian fossil energy, the import of which has already ceased almost completely. According to the strategy, Finland can achieve its climate target by 2030 (a 60% reduction in total greenhouse gas emissions compared to the 1990 level) and carbon neutrality by 2035. The strategy addresses key issues in reducing emissions, which include electrification and the use of system integration, which helps reduce emissions in sectors where this is otherwise difficult, promoting non-combustion heat production, tax treatment of waste heat and industrial-sized heat pumps, and increased market-based generation of land-based wind energy, offshore wind demonstration projects and investments in them, and the use of leased water areas in Finland's territorial waters. Additional funding of €150 million for new technologies, domestic wood chips, and the hydrogen economy is also suggested in the strategy.[8]

Strategy and development in relation to hydrogen and electrification

The national climate and energy strategy also includes the national hydrogen strategy, ie the next steps regarding hydrogen economy and electrofuels, and considers issues relating to electrification and the use of system integration.[9]

The national hydrogen strategy sets the quantitative targets for hydrogen electrolysis capacity. As the technology develops faster, it is possible to develop greater electrolysis capacity. The targets for electrolysis capacity are the following:

- at least 200MW for 2025 (9MW in 2021); and
- at least 1000MW for 2030, taking into account the commercialisation of hydrogen technology.[10]

Concrete actions to be taken in relation to hydrogen projects are being planned and are also under way. For example, Finland's first Power-to-X-to-Power hydrogen system will be built in Vaasa, located on the west coast of Finland. Together with other Vaasa-based organisations, a company called EPV Energy intends to produce hydrogen from the wind and electricity from hydrogen.[11]

Reducing the use of peat

The current government programme aims to reduce the use of peat as an energy source so that the peat use will be reduced by 50% by 2030. On 1 January 2022, the Act on Excise Duty on Electricity and Certain Fuels[12] was amended and taxes on the use of peat became stricter. According to the amended provision in the Act, additional tax must be paid on peat use if the sum of the market price of peat and the market price of emission rights is less than €18.63 per megawatt hour.

Developments in the natural gas sector

The Balticconnector and the end of market isolation

Finland has no gas reserves of its own and, for a long time, Finland was isolated from the rest of the EU's natural gas markets as well as dependent on the gas imported from Russia. In 2020, at the same time the natural gas market in Finland opened up to competition, the first gas interconnector between Estonia and Finland, the Balticconnector pipeline ("Balticconnector"), started operating.[13]

Baltic Connector Oy is a Finnish state-owned company which, together with Estonian Elering AS, built the submarine pipeline that connects the Finnish gas network to the European gas markets, thereby ending Finland's isolation from the EU internal market and making it possible to diversify the sources of supply in the Baltic-Finnish region.[14]

There are still also two parallel pipelines between Finland and Russia, both operated by Gasgrid Finland Oy. However, in May 2022, Russia suspended gas imports to Finland and the Balticconnector is currently the only pipeline importing gas to Finland. Therefore, as the Balticconnector decreased Finland's dependency on Russian gas, it acted as a safeguard after Russia's suspension of gas imports to Finland.[15]

LNG floating terminal

As an alternative to Finnish gas imports, Finland investigated (in cooperation with Estonia) the opportunity to lease an LNG floating terminal vessel, or floating storage and regasification unit ("FSRU"). This was considered to enable Finland to become more independent in terms of natural gas supply and to ensure security of supply in uncertain or unpredictable situations. The LNG floating terminal was considered as the fastest solution and would secure the energy supply for both industry and households for a long time to come.[16]

In August 2022, Gasgrid Finland Oy and Fortum signed an agreement to place the FSRU in Fortum's port in Inkoo, located on the south coast of Finland near the Balticconnector. The aim is that the LNG floating terminal would start operating during January 2023. The LNG floating terminal is anchored to the port structure and, although its final location is in Finland, the liquified natural gas will also be exported to Estonia via the Balticconnector.

Developments in the nuclear energy sector

There have been two ongoing projects for the construction of new nuclear plants in Finland; Hanhikivi 1, a unit in Finland's planned third nuclear power site, Pyhäjoki, commissioned by Fennovoima Oy ("Fennovoima"), and a third unit in Olkiluoto, Eurajoki, commissioned by Teollisuuden Voima Oy ("TVO").

However, following the war in Ukraine, the Hanhikivi 1 project has been halted. Fennovoima, a Finnish nuclear power company, has been planning since the 2000s to build a nuclear power unit with a capacity of 1,200MW in the coastal municipality of Pyhäjoki, located in Northern Ostrobothnia on the shore of the Baltic Sea. Fennovoima has two owners, Voimaosakeyhtiö SF Oy (66%) and RAOS Voima Oy (34%), the latter being a subsidiary of Rosatom Energy International. Rosatom is a Russian state-owned company, which controls all sectors of nuclear energy in Russia. Voimaosakeyhtiö SF Oy is owned by industrial and trading companies as well as local energy utilities, which are mainly owned by municipalities.[17]

Fennovoima concluded a power plant supply agreement with Rosatom Energy International (part of the Rosatom-group) in December 2013, and Rosatom's subsidiary, RAOS Project Oy, was to execute the project in Finland.[18] However, in May 2022, Fennovoima submitted to the Ministry of Economic Affairs and Employment a notification by which it cancelled the construction licence application concerning the Hanhikivi 1 nuclear power plant. It also announced it had terminated the plant delivery contract with RAOS Project Oy and the nuclear fuel delivery agreement with Rosatom's subsidiary TVEL Fuel Company. Fennovoima has initiated several arbitrations and other proceedings against various Rosatom entities to claim compensation for damage arising out of the delays and inability to deliver the project and related issues. Fennovoima's claims currently amount to almost €2 billion.[19] Rosatom, in turn, is seeking $3 billion in damages from the Fennovoima consortium for halting the project.[20] The disputes have not yet been resolved.

The other ongoing project concerning the construction of a new nuclear plant, Olkiluoto 3, has progressed to its final stages and was connected to the national grid in March 2022. The plant is currently in the test production phase and is expected to begin regular electricity production in March 2023.[21] The Olkiluoto 3 project has experienced many setbacks. The cost estimate for the project was initially about €4 billion, but currently the highest estimates place the price at €11 billion, causing Olkiluoto 3 to appear on lists of the world's most expensive building projects.[22] Olkiluoto 3 is highly expected to alleviate the current energy crisis, as the plant's electricity production is estimated to cover about 14% of Finland's electricity demand. According to TVO, Finland's self-sufficiency in non-carbon fuel electricity will grow, as the share of carbon-free electricity production will rise from 87% to over 90%, and the electricity production from Olkiluoto 3 will also reduce Finland's electricity imports by about 60%.[23]

Other energy-related projects

The Finnish Metsähallitus (ie the Finnish Forest and Park Service) is currently developing the biggest wind farm (which is also one of the first offshore of its kind) in Finland, located 15-30 km off the coast of Korsnäs municipality, on the west coast of Finland. The municipality of Korsnäs approved Metsähallitus' planning initiative for the offshore wind farm in autumn 2020, and the project is still in the development phase. It is estimated that the Korsnäs offshore wind farm could be in production by 2028 at the earliest.[24] Prior to Korsnäs farm there has been one, smaller offshore wind farm in Pori, Finland which, even though operational since 2017, has been more of a demonstration project.[25]

The wind power market is expected to grow in Finland in upcoming years. Currently, wind power accounts for about ten per cent of electricity consumed in Finland and it is predicted that in 2025 wind power will account for at least 27% of electricity consumption. It is estimated that there will be over 1,000 wind turbine generators with a total nominal output of at least 5,000MW in 2022 and that total investments in wind power will be about €6 billion between 2022 and 2025.[26]

In 2022, alliance partners Helen Ltd (a Finnish energy company), YIT (a Finnish construction company), and ACCIONA (a Spanish developer of sustainable infrastructure solutions) began the design and development of a tunnel system in a seawater heat recovery project in Salmisaari, Helsinki. The works will start a two-year development phase. The heat recovery project will supply seawater throughout the year to heat pumps being constructed in Salmisaari. The heat pumps use less than +2 degrees Celsius seawater and electricity for district heating production. The heat that is produced is delivered to customers via the district heating network. In addition to heating, the heat pumps can be used to produce cooling energy during the summer. The heat from seawater is renewable, and the heat source is inexhaustible.[27]

There are currently several green hydrogen projects being developed in Finland and the production of green hydrogen is estimated to significantly increase in 2025. The construction works of the first green hydrogen production plant developed by P2X Solutions are estimated to finish during summer 2024. The largest green hydrogen project made public is a €500 million investment by development company Flexens. The facility will be located in Kokkola and is estimated to commence its operation during 2027. Another large green hydrogen facility is planned to be developed by CPC Finland and Prime Capital in Kristiinankaupunki. The value of the investment is €450 million, and it is expected that the production of the facility will start during 2025.

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Overview of the legal and regulatory framework in Finland

A. Electricity

A. 1 Industry structure

Nature of the market

Since the enactment of the historic Electricity Market Act ("EMA") in 1995, the Finnish electricity market gradually started to open up to allow competition and is now fully liberalised, except in respect of the operating networks. Since 1998, it has been possible for all electricity users, including domestic households, to purchase electricity from any supplier of their choice.

Key market players

In 2021, Finland's total electricity consumption was 87.1TWh, of which 79.6% was domestically generated and 20.4% was imported.[1] Major companies selling electricity in Finland include Fortum Corporation ("Fortum"), Pohjolan Voima Oy (including Teollisuuden Voima Oyj ("TVO")), Helen Oy, and Vattenfall Oy. Retail electricity agreements with consumers are governed by the EMA, which includes provisions that protect the rights of consumers. Although there are about 120 companies generating electricity in over 400 power plants in Finland, electricity generation is concentrated mainly in three groups, ie Fortum, UPM Energy Oy, and Pohjolan Voima Oy.

The transmission of electricity within the main grid in Finland is operated by Fingrid Oyj ("Fingrid"), which is the Finnish transmission system operator ("TSO"). The major shareholders of Fingrid are the State of Finland (28.24%), Aino Holdingyhtiö Ky (26.41%), and the National Emergency Supply Agency (24.90%).[2] By virtue of the EMA, Fingrid is responsible for the functioning of the main power grid as well as for the management of the national power balancing system. The terms of sale regarding Fingrid's grid services must be equal and non-discriminatory towards all parties in the electricity market.

Electricity is transmitted to distribution systems (ie, distribution networks) and large-scale end users through the main grid and regional grids (110 to 400kV). The electricity is usually distributed further through a 20kV power line from electricity substations. There are some 80 distribution network companies, most of which are owned by municipalities.[3] Electricity retailers sell electricity to households and smaller businesses and usually measure and invoice users' electricity consumption.

Regulatory authorities

In Finland, the national supervisory authority for electricity markets is the Energy Authority ("EA"), an agency that operates under the Finnish Ministry of Economic Affairs and Employment. The EA ensures that there is compliance with the provisions of the EMA and the rules and regulations issued by virtue of the EMA.[4] In addition to the EA, the electricity market is also supervised by the Finnish Competition and Consumer Authority and the Finnish environmental authorities.[5]

Legal framework

The new EMA came into force in September 2013,[6] replacing the EMA of 1995. The EMA has since been amended multiple times. In addition to the EMA, the regulatory framework for the electricity industry consists of decrees issued by the Ministry of Economic Affairs and Employment and the Council of State as well as rules and regulations issued by the EA. The main objective of the reform of the EMA in 2013 was to implement the Third Energy Package into national law and to improve the security of electricity supply, especially in sparsely populated areas. A number of other amendments to the EMA and lower-level decrees have been made afterwards to adopt newer European Union ("EU") legislation.

A.2 Third party access regime

Under the EMA, the TSO and all distribution system operators ("DSOs") must connect all electricity consuming sites and power generating installations to its system within the TSOs or the DSOs area of operation, provided that technical requirements are fulfilled and reasonable compensation is paid. The conditions for connecting and the technical requirements set for the third parties must be transparent, objective, and non-discriminatory. The TSO and DSOs must transmit electricity within their area of operation and within the limits of their transmission capacity.

Under the EMA, DSOs must be independent in terms of legal form, organisation, and decision making from the company's or group of companies' electricity generation and electricity sale activities where:

- the quantity of electricity distributed annually during the previous three calendar years in the DSOs network has been 200GW or more (in a 400V network); and
- the DSO is part of a company or a group of companies engaged in electricity generation or sale, or a group of utilities under the same party's authority.

Additionally, requirements for operative unbundling of DSOs are set by virtue of the EMA. A legally unbundled electricity system operator with 50,000 customers or more must have separate management (including members of the board of directors) from the electricity generation and sales companies if the system operator and the generation/sales company are under the authority of the same party. Further provisions on operative unbundling imposed on companies operating on the electricity market are prescribed in the Decree of the Ministry of

Economic Affairs and Employment on Unbundling of Electricity System Operators[7] and the Decree of the Ministry of Trade and Industry on Operative Unbundling Requirements for the Electricity Distribution System Operators.[8] For small DSOs that have distributed less than 200GWh annually through their 400V network during the previous three calendar years, unbundling through separate accounts is sufficient. Furthermore, separate accounts are not required if the operations are of minor significance in terms of volume or the other trade operations carried out.

Fingrid, as the main grid system operator (the TSO), must also be independent from the electricity generation business and electricity sale operators in terms of its legal structure, its organisation, and its decision-making procedures. Any distribution network operations must also be unbundled from the transmission network operations. Under the EMA, Fingrid as the TSO is subject to ownership unbundling, meaning, among other things, that the same person may not directly or indirectly own shares both in Fingrid and an electricity or natural gas producer, wholesaler, or retailer.

A.3 Market design

Nord Pool is the largest market for electricity in Europe in terms of volume traded (TWh) and market share. More than 80% of the total consumption of electrical energy in the Nordic market is traded through Nord Pool. 66% of Nord Pool is owned by the Norwegian company Euronext Nordics Holding AS and the remaining 34% by TSO Holding AS, which is owned by the Nordic and Baltic TSOs.[9] Nord Pool is one of the three nominated electricity market operators ("NEMO") in the Multi-NEMO Arrangement that was implemented in the Nordic Region, including Finland, in 2020.[10]

No licence or registration obligations are set for the retail sale of electricity. A customer can choose whichever electricity supplier it wants, as long as it pays the necessary fees to the network operator. Customers cannot invite tenders regarding the network services, but they have to use the network service provider in the geographical area where the customer is located. The network service price cannot depend on where the customer resides or from which electricity seller the customer is buying the electricity.

Additionally, under the EMA, electricity must be available to all end users and, therefore, the electricity network operators must transmit and distribute electricity between existing networks for reasonable compensation.

A.4 Tariff regulation

In the Finnish electricity market, there are separate tariffs for electricity network services and the supply of electricity. Under the EMA, the tariffs for network services, terms of the system services and the criteria according to which they are determined must be available to the public and they must be equitable and non-discriminatory to all system users. Additionally, the pricing of system services must be reasonable and not restrict competition. Pricing of network services and sales conditions cannot contain provisions that could have adverse effects on overall efficiency or energy efficiency of generation, transfer, distribution, or supply of electricity. However, electricity purchase prices, ie the supply of electricity, are not subject to a regulatory regime.

The EA assesses whether the pricing of both distribution and transmission network services is reasonable. Under the Act on Supervision of Electricity and Natural Gas Markets, economic regulation is based on regulatory periods consisting of two sets of four years. Before the start of each regulatory period, the EA establishes ex-ante the methodology ensuring reasonable pricing for customers and determining a reasonable return to the network operator for the upcoming regulatory period. The current and fifth regulatory period started on 1 January 2020 and will end on 31 December 2023.

The regulatory methodology set by the EA, establishes the manner in which reasonable return and the realised adjusted profit of the network operators are to be calculated. This methodology is applied by the EA in its individual decisions concerning each network operator's pricing and reasonable rate of return. The annual adjusted profit of the network operator is calculated based on unbundled accounts of the electricity network business and certain other data relating to the composition of the electricity network as well as economic and technical data. The profit that a network operator makes in a given year may be above or below the annual reasonable return. Based on information submitted by each network operator to the EA, the EA calculates and informs each respective network operator on such regulatory surplus or deficit on an annual basis. After each regulatory period, the EA confirms the aggregate surplus or deficit of each respective network operator for the regulatory period. An aggregate surplus decreases, and an aggregate deficit increases the total reasonable return for the following regulatory period with the corresponding amount.

Under the EMA, a network operator may increase its electricity transmission and distribution charges by a maximum of 8% when compared to the charges collected in the past 12 months. The EA monitors price increases. The monitoring of price increases does not influence the assessment of reasonable pricing according to the regulatory method.

A.5 Market entry

There are no significant barriers to entry into the Finnish electricity market as long as the operator fulfils the legal requirements set out in the electricity market legislation. However, electricity system operation is a licensed activity (see below, Licensing regime).

Licensing regime

Electricity system operation requires a grid licence granted by the EA. The licence requirement concerns both the TSO and the DSOs. The licence is granted if the applicant has the technical, economic, and organisational capabilities that are needed for conducting its electricity system operations. The licence is valid until further notice unless there are particular reasons to grant the licence for a fixed period of time. For a DSO, the licence also specifies the geographical area, where the DSO has the exclusive right to operate a distribution network. A grid licence cannot be transferred to another operator. Contrary to network operations, the EMA does not set any licence or registration requirements for the retail sale of electricity (ie the supply of electricity).

A.6 Public service obligations and smart metering

Public service obligations (PSOs)

The Act on Safeguarding Security of Supply aims to safeguard the technical infrastructure and economic activities that are necessary for securing and maintaining safety, the national economy, and national defence in the event of a crisis. The operation of the main grid is considered to be one of these critical services, the functioning of which must therefore be ensured.[11] The EMA includes an obligation on the TSO to ensure the technical functionality and operational reliability of the main grid.

Under the EMA, an electricity retailer in a major market position within the area of responsibility of a DSO must deliver electricity at reasonable prices to consumers and certain other users of electricity.

There is also a peak load reserve system in Finland. Power plant operators can offer their power plants to be used in the system and, when the power plant operator's offer is acceptable, the TSO concludes an agreement with them. The power plant operator must follow and fulfil the obligations and conditions set out in the Act on Peak Load Power Reserves Securing the Balance between Electricity Consumption and Production.[12]

Smart metering

The measuring of electricity consumption and small-scale electricity generation must, with a few exceptions, be based on hourly measuring and remote reading of the measuring equipment. DSOs must report the hourly consumption of electricity to customers without a separate fee.[13] As a rule, electricity consumption in Finland is metered remotely.[14]

Electric vehicles

At the end of 2021, there were over 99,910 electric cars in Finland, about 25% of which were fully electric.[15] Reaching 250,000 electric cars by the end of 2030 is one of the targets set in the national energy and climate strategy of Finland.[16] Since last updating the national energy and climate strategy, the government of Finland ("Government") has expressed a new goal of over 700,000 electric cars by the end of 2030.[17] The Government supports the purchase of electric cars by, for example, providing a non-recurring support of €2,000 for the purchasers of electric cars until the end of 2023. In addition, the state of Finland has supported the construction of public charging points and the charging points of housing companies by granting direct subsidies and through a support scheme targeted for charging and refuelling infrastructures for electric and gas vehicles.[18] Another way in which the Government has aimed to increase the number of electric cars is by abolishing the car tax for fully electric cars.

In addition to cars, electricity is used extensively in railway traffic. In 2017, more than half of the railway network in Finland had been electrified and therefore made compatible with electric trains. However, according to a report published by the Finnish Transport Agency in 2018, modernising old diesel locomotives is considered a more efficient way of reducing carbon dioxide ("CO_2") emissions than proceeding with the electrification of the remaining parts of the railway network. Therefore, further decisions concerning the electrification of the railway network are made using case-by-case discretion.[19]

A.7 Cross-border interconnectors

The main grid of Finland is part of the synchronous Nordic system together with Sweden, Norway, and part of Denmark. Fingrid operates interconnectors between Finland and its neighbouring countries Sweden and Norway. In addition to the Fingrid-operated interconnectors, there are two interconnections between Finland and Estonia, which are jointly owned by Fingrid and Elering. Other interconnector projects include the commissioning by Fingrid of an interconnector between Finland and Sweden, which was completed in late 2011. A new interconnection with a capacity of 100MW was also built between the Åland Islands and mainland Finland by Kraftnät Åland in 2015. The interconnector is used as a reserve and is intended to ensure security of supply in the Åland Islands.[20] A new interconnection between Northern Finland and Sweden is planned to be completed in 2025.[21]

The operations of the interconnectors are supervised by the Ministry of Economic Affairs and Employment. Under the EMA, the construction of cross-border power lines with a nominal voltage of 110kV or higher requires a licence from the Ministry of Economic Affairs and Employment. The import and export of electricity is not regulated and therefore does not require a licence.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Since there are no natural oil resources in Finland, all oil is imported, and a substantial amount of the crude oil used in Finland is transported via oil tankers from Russia. According to recent news reports, Finland imports a substantial proportion of oil from Russia. Nonetheless, crude oil and petroleum products are also imported to a significant extent from elsewhere, and the Russian impact on the Finnish oil markets has diminished.[22]

For many years, oil as a source of energy fulfilled nearly a quarter of the energy demand in Finland. However, as a result of generally reducing the use of fossil fuels, the share of oil as an energy source has diminished, although it still constitutes a significant proportion of Finland's energy mix. In 2021, oil accounted for 21% of the total energy consumption in Finland, while in 2016 the percentage was 23.6%.[23] As a country, Finland is not as oil dependant as the average of other Organisation for Economic Co-operation and Development (ie OECD) countries in the world.[24]

Key market players

The key market players in the Finnish oil sector are Neste Corporation ("Neste"), SEO (a Finnish energy cooperative), St1 Oy ("St1"), Suomen Osuuskauppojen Keskuskunta SOK ("S Group"), and Oy Teboil Ab ("Teboil").

In practice, crude oil is imported to Finland only for the needs of Neste, and about two-thirds of the crude oil used by Neste is currently sourced from Russia. Other distribution chains purchase petrol, diesel, and other petroleum products from Sweden and elsewhere in Western Europe, in addition to sourcing products from the Porvoo refinery owned by Neste, which is currently the only oil refinery in Finland.[25]

Under Finland's Long-Term Climate and Energy Strategy ("LCES"), the aim is to increase biofuels and decrease Finland's dependency on oil and oil products. The strategy has already had clear impacts on the Finnish oil market. One sign of a change in the oil market is that the Oil and Biofuels Industry Association (Fi. *Öljy- ja biopolttoaineala ry*) ceased its operations in 2019 due to differences of opinion. The members of the association included some of the aforementioned key market players.

Gas

Nature of the market

Since there are no natural gas resources in Finland, all of the natural gas is imported. Most of the natural gas used in Finland is currently imported by Gazprom, the Russian Public Joint Stock Company. In 2020, about 64% of the natural gas imported to Finland was of Russian origin. In addition to Russia, other important natural gas supplier countries are Estonia and Norway.[26] Liquefied natural gas ("LNG") is imported to Finland by ship, and biogas produced in Finland is supplied into the natural gas network in small quantities.[27] In 2020, natural gas accounted for 6% of Finland's total energy consumption.[28]

Finland belongs to the same natural gas market area as Estonia and Latvia. In 2020, the Finnish natural gas market opened for competition as required by the Natural Gas Market Act ("NGMA"), which has been in force since the beginning of 2018. The Act also requires separation of a company that previously had a monopoly, Gasum Oy ("Gasum"), into companies with separate ownership bases for transmission and sales.[29]

Key market players

Prior to 2020, Gasum was the only importer and wholesale supplier of natural gas in Finland.[30] Gasum has been wholly owned by the Finnish State ("State") since November 2015, with 73.5% of the shares held by the state-owned Gasonia Oy and 26.5% by the State directly. Previously, Gasum was the TSO and also owned and operated the natural gas transmission network. However, from 2020, the transmission network company Gasgrid Finland Oy ("Gasgrid") has been responsible for gas transmission in Finland.[31] Gasgrid is also responsible for maintaining the Virtual Trading Point ("VTP"), in which all gas transfers that take place in the Finnish market are registered.[32]

Unlike most of Europe, the distribution of natural gas to private households and other minor consumers is not significant in Finland. In 2020, there were 18 local DSOs. The retail supply of natural gas covers only about 7% of the total consumption. Different suppliers have a different customer base, some gas suppliers serve mainly households while others have only industrial customers.[33]

Regulatory authorities

As with the electricity market, the EA promotes the operation of a competitive natural gas market and supervises compliance with the Finnish NGMA. The Finnish oil market is not specifically regulated, but the use of oil is heavily taxed.

Legal framework

The regulatory framework for the natural gas industry consists of the NGMA, decrees issued by the Ministry of Economic Affairs and Employment, and rules and regulations issued by the EA.[34] In June 2017, the Finnish Parliament ("Parliament") approved the NGMA, which came into force on 1 January 2018. As briefly mentioned, the main points of the new act include:

- opening of the wholesale and retail gas markets for competition starting from the beginning of 2020;
- unbundling of the natural gas transmission system from the production and sale of natural gas by 2020;
- rules for regulated third party access to; and
- regulation of LNG facilities as well as limitations to unreasonable increases of the transmission and distribution fees for gas.

B.2 Third party access regime to gas transportation networks

In 2017, the Finnish gas sector consisted of one TSO and fewer than 25 DSOs, and the gas transmission and distribution network only covered the southern parts of Finland. Currently, the number of DSOs has decreased. However, under the NGMA, a network operator must supply natural gas to customers and connect users to the network upon request and in return for reasonable compensation. Therefore, as a result of the opening of the gas market, third parties have equal and non-discriminatory network access to the natural gas transmission and distribution networks.[35]

According to Section 94 of the NGMA, based on an application by a network operator, the EA may grant the network operator a temporary exemption from its duty to carry out transmission and distribution services. This is in the event of serious economic or financial difficulties as a result of a take-or-pay undertaking under a long-term natural gas supply contract. Such an exemption must be applied for before the network operator can refuse to provide transmission and distribution services. According to Section 93 of the NGMA, the EA may also exempt the network operator from the obligation to provide transmission and distribution services and publish network and retail tariffs, if the network operator has invested significantly in the natural gas network, eg by building a connecting pipeline to another EU Member State or a gas storage facility.

B.3 LNG terminals and storage facilities

In October 2016, the first Finnish LNG terminal was opened in Pori by Skangas Oy (a subsidiary of Gasum).[36] The second LNG terminal in Finland and the biggest terminal in the Nordic Countries is located in Tornio.[37] In addition, a new LNG terminal to Hamina has been finalised and taken into commercial use in the autumn 2022. The terminal in Hamina is the first LNG terminal that is connected to the Finnish national gas grid as well as the local gas network in Hamina.[38]

As an alternative to Finnish gas imports, Finland investigated (in cooperation with Estonia) the opportunity to lease an LNG floating terminal vessel, or floating storage and regasification unit ("FSRU"). In August 2022, Gasgrid Finland Oy and Fortum signed an agreement to place the FSRU in Fortum's port in Inkoo, located on the south coast of Finland, near the pipeline between Estonia and Finland ("Balticconnector"). The aim is that the LNG floating terminal would start operating during January 2023. Although the final location of the LNG floating terminal is in Finland, the liquified natural gas will also be exported to Estonia via Balticconnector.

The Ministry of Economic Affairs and Employment has previously granted investment subsidies for various LNG terminal construction projects. A small-scale LNG terminal and an LNG fuelled ferry in Vaasa are also planned.[39]

Under the NGMA, an LNG system operator must provide access to the facility for reasonable compensation and within the limits of the facility's capacity. In relation to access to gas storage, Finland has chosen to implement the negotiated access option. Negotiations between the parties must be carried out in good faith and conditions, including tariffs, must be reasonable and non-discriminatory.

B.4 Tariff regulation

Under the NGMA, a network operator must publish its general terms of sales and tariffs. The network operator may set the tariffs itself as long as the tariffs treat each party equally, are non-discriminatory and reasonable for all network users, and do not restrict competition within the natural gas market. The transportation tariff must not depend on the geographical location of the customer. The EA may intervene to ensure compliance with the natural gas market legislation.

The EA assesses whether natural gas transportation tariffs over four-year periods are reasonable. The previous supervisory period ran from 1 January 2016 to 31 December 2019. Tariff regulation methods determining the reasonable target profit for network operators are decided by the EA for two consecutive four-year supervision periods. Therefore, the current regulation methods are in force until 31 December 2023.[40] The EA defines reasonable profit targets for network operators and decides on the methods of calculating the profit. If, after a four-year supervisory period, the EA establishes that a network operator's profit has deviated from the reasonable profit target, a network operator must either return any excess profit to its customers by lowering the network tariff for the next supervision period or increase the network tariff in the next supervision period to be reimbursed for the low profit level of the previous supervision period.

B.5 Market entry

Operating a natural gas network requires a licence, which is issued by the EA. If the applicant fulfils the prerequisites set out in the natural gas market legislation, the licence is granted until further notice or, under specific circumstances, for a fixed period.[41] Under the NGMA, an entity engaged in the natural gas business must unbundle its natural gas network operations, LNG facilities, its businesses carrying out the sale and storage of gas, and any other business operations that are not in the natural gas sector by maintaining separate bookkeeping for the different operations mentioned.

The sale of natural gas does not require a licence. However, a retailer with a significant market position or with the greatest market share in the operating area must fulfil certain obligations, such as supplying natural gas to certain customers for a reasonable price and publishing the terms of sale and sale prices of natural gas.

B.6 Public service obligations and smart metering

In relation to PSOs mentioned in the EUs Third Gas Directive, there are two types of gas delivery obligations set out in the NGMA. A natural gas wholesaler who has significant market power in a natural gas transmission pipeline must deliver gas on equal and non-discriminatory terms to retail sellers it has acquired through an interconnector pipeline that is linked to a natural gas pipeline from Russia.

Correspondingly, a retail seller who has significant market power within a distribution pipeline must deliver natural gas within this territory to an end user who uses natural gas mainly for residential heating and also to end users whose connection capacity is, at most, 250kW.

Under the NGMA, the obligation to sell transmission services set to the TSO applies only if the metering is done by smart meters. In addition, according to the NGMA, the imbalance settlement must be based on the metering with smart meters and notifications regarding supply.

B.7 Cross-border interconnectors

By virtue of the NGMA, the Ministry of Economic Affairs and Employment has the authority to issue a licence for the construction of a transmission pipeline that crosses the national border.

The Balticconnector was opened at the beginning of 2020, when the natural gas market in Finland was opened for competition.[42] Baltic Connector Oy is a Finnish state-owned company and, together with Estonian Elering AS, they built the submarine pipeline that connects the Finnish gas network to the European gas markets, thereby ending Finland's isolation from the EU internal market. As the project was an EU Project of Common Interest ("PCI"), Balticconnector received €87.5 million in investment aid from Connecting Europe Facility fo Energy.[43]

C. Energy trading

C.1 Electricity trading

Wholesale markets

Finland, Norway, Sweden, Denmark, Estonia, Latvia, and Lithuania have deregulated their electricity markets and formed a common electricity market based on the electricity exchange Nord Pool, where the market price of electricity is established. Presently, the Nord Pool also operates in other European countries, such as Germany and the UK.[44] In Nord Pool, physical electricity is traded and financial instruments are quoted on the Nord Pool exchange in a day-ahead market, Elspot, and an intraday market, Elbas. The exchange quotes the day-ahead market price for each hour of the day based on the purchase and sale bids. The Elbas intraday markets are open 24/7, 365 days a year offering 15-minute, 30-minute, hourly, and block products. In Finland, it is possible to trade up until delivery.[45] Elbas functions as a balancing market for the Elspot day-ahead market. Although the competition between the power exchanges began in 2020, the share of electricity procured from Nord Pool power exchange still covered 70% of the Finnish physical consumption in 2020. Electricity procurement from the second largest NEMO, EPEX SPOT, was considerably lower, and covered less than 4% of Finnish electricity consumption in 2020.[46]

Additionally, there are cross-border connections between Russia and Finland based on agreements between Fingrid and Russian national grid parties, enabling two-way trade in electricity between the countries. There are two modes of power trade between Russia and Finland, bilateral trade and direct trade.[47]

Retail markets

Fingrid has developed a centralised information exchange system ("Datahub") for the electricity retail market, allowing for information to be equally and simultaneously accessed. The Datahub system was launched in February 2022 and contains data from 3.8 million electricity metering points in Finland. This information will be used by about 80 electricity suppliers and 80 DSOs serving electricity consumers. Datahub contains information on, eg electricity consumption and electricity agreements. Furthermore, a customer service portal is planned to be launched in the future.[48]

C.2 Gas trading

Since 1 January 2020, the Finnish gas market has been open for competition and Gasgrid became responsible for gas transmission in Finland. Gasgrid is also responsible for maintaining the VTP, in which all gas transfers in Finland are registered. The VTP is an information system in which all market participants report their gas energy transfers. In the Finnish market model, all gas that is injected into and withdrawn from the market area goes through the VTP.[49]

In Finland, trading in gas energy and transmission capacity takes place in the wholesale market. In accordance with EU legislation, the entry-exit system is applied to Finnish gas trading. In the entry-exit system, physical and commercial gas flows are separated from each other, enabling efficient operations in the market. Gasgrid Finland is responsible for selling transmission capacity in the system, and the shippers and traders are responsible for selling gas energy. In the entry-exit system, the gas enters the Finnish gas system via entry points in Imatra and Inkoo and flows out of the Finnish system via exit points to the Balticconnector. In addition, there is the aggregated virtual entry point formed by biogas plants.[50] In the exit zone, gas is transmitted from the transmission network to an end user or to a gas network with lower pressure. In the future, LNG may also become part of the Finnish entry-exit system.

Starting from 1 January 2020, a company called UAB GET Baltic has been delivering gas exchange services to the Finnish gas market. UAB GET Baltic administers the electronic trading system (ETS) for trading spot and forward natural gas products with physical delivery in the market areas located in Lithuania, Latvia, Estonia, and Finland.[51]

D. Nuclear energy

In 2021, 32.9% of the electricity generated in Finland was generated by nuclear power.[52] Finland has two nuclear power plant sites operating commercially: one in Olkiluoto, Eurajoki and one in Loviisa. Olkiluoto also has a third unit which is currently in a test production phase and is expected to begin regular electricity production in March 2023.[53] A further nuclear power plant was planned to be constructed in Pyhäjoki by Fennovoima Oy ("Fennovoima"), which is 66% owned by a joint venture of major corporations operating in Finland, and 34% owned by a Finnish subsidiary of Rosatom, the Russian State Nuclear Energy Corporation that was supplying the plant. Fennovoima terminated the engineering, procurement, and construction contract of plant delivery with RAOS Project Oy (Rosatom's project company) due to RAOS Project Oy's significant delays and inability to deliver the project.[54] Further, Fennovoima withdrew its nuclear power plant Construction Licence Application.[55] Fennovoima has initiated several arbitrations and other proceedings against various Rosatom entities.[56]

Matters relating to nuclear power are regulated under the Nuclear Energy Act ("NEA") and the Nuclear Energy Decree, and other regulations, mainly issued by the Finnish Ministry of Economic Affairs and Employment.[57] The NEA sets out the requirements for construction permits, operating licences and use of nuclear facilities, use of nuclear fuels, and nuclear waste management policies. Operating licences are granted for a fixed term.

The latest amendment to the NEA came into force in 2020. The amendments mainly included provisions on health and safety in nuclear power plant sites. The NEA was previously amended in early 2018 to incorporate the provisions contained in the Spent Fuel and Radioactive Waste Directive.[58]

Under the NEA, producers of nuclear waste are individually responsible for the management and disposal of nuclear waste, as well as for the financing of such operations. Nuclear waste generated in Finland must be disposed of within Finland. After the final disposal of all nuclear waste in accordance with the set requirements, the producers of nuclear waste are released from liability.

The final disposal of nuclear waste and decommissioning of nuclear power plants is under development and is being carried out by Posiva Oy ("Posiva"). Posiva applied for the operating licence on December 2021.[59] After the final disposal has been put into operation, the final disposal canister is disposed by being placed in the tunnels, 400 to 450 metres underground in the bedrock.[60] The final disposal is scheduled to start in 2025 and a trial run is scheduled to begin in 2023.[61] Currently, used nuclear fuel is stored in water storage basins located at the sites of nuclear power plants.[62]

Funds for the future costs of conditioning, storing, and disposing of spent fuel and low and intermediate level waste, as well as for the costs of decommissioning of the nuclear plants, are collected by means of annual contributions to the Finnish Nuclear Waste Management Fund by the companies operating nuclear power plants.[63]

The nuclear power plants are supervised by the Radiation and Nuclear Safety Authority ("STUK"). The other regulating authorities are the Council of State and the Finnish Ministry of Economic Affairs and Employment. Additionally, the use of nuclear fuel is supervised by the International Atomic Energy Agency ("IAEA") and the European Atomic Energy Community ("EURATOM").

Under a compensation scheme in the Nuclear Liability Act, adopted by Parliament in 2011, compensation for damage incurred in Finland arising from a Finnish nuclear incident has, from 2012, been based on an unlimited liability approach.[64] Therefore, the liability of an operator of a Finnish nuclear power plant for damage occurring in Finland from a nuclear incident will be unlimited. As for damage occurring abroad from such a nuclear incident, the liability of the Finnish operator will be no more than 600 million Special Drawing Rights ("SDR"), which currently corresponds to about €700 million.[65] The value of the SDR is determined daily, based on a basket of five major currencies.[66]

E. Upstream

There are no upstream resources in Finland.

F. Renewable energy

F.1 Renewable energy

Under the Renewable Energy Directive, the EUs target was to raise the share of renewable energy sources to 20% of energy end-consumption by 2020. The binding target set for Finland in the directive was 38%. In 2021, Finland significantly exceeded the target set in the Directive as the share of renewable energy continued to grow, covering 42% of the total final energy consumption in 2021.[67]

To meet Finland's 2020 obligation, the following three notable Government proposals regarding the promotion of energy production from renewable sources were passed at the end of 2010 and came into force at the beginning of 2011:

- Act on Production Subsidy for Electricity Generated from Renewable Energy Resources ("PSRESA") establishing a state-funded subsidy scheme of feed-in tariffs for electricity generation based on wind power, wood-based fuel, and biogas, as well as a tendering-based subsidy scheme for wind power, combined heat and power ("CHP"), biogas, solar power, and wave power.[68]
- Amended Act on Promoting Use of Biofuels in Transportation (446/2007, as amended) ("PUBTA") introducing an increased biofuel distribution obligation for fuel distributors.[69]
- Amended Act on Production Tax for Liquid Fuel introducing an energy tax reform.[70]

In addition to the above measures, the Act on Subsidies for Energy Wood was enacted in 2011 and was expected to enter into force in 2012.[71] However, in the spring of 2012, the European Commission ("Commission") considered the subsidy scheme to be contrary to state aid rules, which forced the Government to make some adjustments to the scheme. The original act was replaced by the Temporary Act on the Financing of Sustainable Forestry, which came into force on 1 June 2015, and which will be in force until 31 December 2023.

Currently, the Finnish Land Use and Building Act is under comprehensive reform. The main objectives of the reform are to promote a carbon-neutral society, strengthen biodiversity, improve the quality of construction, and advance digitalisation by eg improving the energy efficiency of buildings, increasing the use of smart technology in buildings, and improving the charging capacity of electric vehicles. The government proposal of the Land Use and Building Act was passed to and approved by the Finnish Government on 15 September 2022. The aim is that the new legislation would enter into force on 1 January 2024.[72]

F.2 Renewable pre-qualifications

In relation to the Finnish feed-in tariff scheme, electricity generators accepted into the scheme may receive a subsidy for a period of up to 12 years. Under the PSRESA, the feed-in tariff is the guaranteed price for electricity (€83.50 per MWh) reduced by the three-month average market price of electricity in the area where the plant is located. However, if the three-month average price is less than €30, the feed-in tariff is the target price reduced by €30 per MWh. The PSRESA covers wood-based renewables, biogas, and wind power.

In addition to the guaranteed price, small CHP plants using wood-based fuel and CHP biogas power plants will receive a premium for heat that is generated together with electricity. Small CHP plants using wood-based fuel receive €20 per MWh and biogas power plants receive €50 per MWh additional heat premium on top of the feed-in tariff for efficient heat production.

The feed-in tariff scheme is currently fully booked with respect to wind power. Additionally, in 2018 it was decided that the feed-in tariff system for power plants using wood-based fuel and power plants using biogas would be closed, as the tendering-based subsidy scheme was subsequently available (now closed, see below). The feed-in tariff for electricity generated with wood chips is different from the above as it fluctuates on the basis of a calculation methodology involving the market price of an EU Emissions Trading Scheme ("EU ETS"), emissions allowance ("EUA"), and the level of national taxation on peat. No heat premium is paid for a power plant that is included in the feed-in tariff scheme as a power plant using wood chips. In 2021, it was decided that the feed-in tariff system for power plants using wood chips would close and no further applications of inclusion would be accepted as of 15 March 2021.

An amendment to the PSRESA entered into force on 25 June 2018, under which a new technology neutral production subsidy scheme for renewable energy sources based on a bidding process was implemented.[73] Under the new technology neutral tendering scheme, the EA auctions subsidies for an annual production of 1.36TWh of renewable energy. Wind power, CHP, biogas, solar power, and wave power plants located in Finland are all eligible to apply. Seven projects were granted the subsidy in the first auction round in 2018. The PSRESA does not set out how many auction rounds will be held. Each auction round must be based on the annual state budget, which will include the maximum amount of annual electricity generation from renewable energy sources that can be offered that year. No new bidding rounds have been announced since the auction round in 2018.

Eligible electricity generators can submit bids for the level of support (ie, a premium) they require to generate a defined annual amount of renewable electricity. The granted premium is variable, being determined by comparing the area average market price of electricity to a reference price (€30 per MWh). The premium will therefore decrease or may not be paid if the price that the electricity generator has bid is obtained by way of the market price of electricity without the premium. Eligible tenderers offering the lowest premiums will be approved in the premium scheme until the accepted offers use up the auctioned 1.36TWh; the tender that leads to the 1.36TWh threshold being exceeded is the first to be denied access.

Apart from the feed-in tariff system, the Ministry of Economic Affairs and Employment can grant state aid for innovative energy projects. State aid in the energy sector may currently be granted provided the investments or research projects (i) promote the production or use of renewable energy; (ii) increase the efficiency of energy saving, energy production or use; or (iii) otherwise promote the energy system to become low carbon. Investments in renewable energy use that are eligible for support are: (i) small-scale electricity and heat production projects; (ii) projects producing biofuels for transportation; and (iii) demonstration projects for new technology. Investments in energy savings and energy efficiency that are eligible for support are: (i) projects involving conventional technology for beneficiaries that have signed an energy efficiency agreement; (ii) demonstration projects for new technology; and (iii) Energy Service Company (ESCO) projects. Additionally, aid can be granted for energy audits and energy analyses concerning energy saving, more efficient energy use, and the use of renewable energy. Energy aid can be granted if the project or the new technology included in the project would not be implemented without the aid. Energy aid may be granted to companies, municipalities, and other organisations.[74]

In addition to the aforementioned subsidies, there are other subsidy schemes relating to nature conservation in Finland. The Ministry of the Environment grants state aid for nature conservation projects, environmental projects, housing and building associations, acquisition of recreational areas, and research and development projects.[75] The Ministry of the Environment also coordinates certain types of aid granted by the EU. Additionally, the Ministry of Agriculture and Forestry of Finland can grant different types of aid and subsidies to entrepreneurs in all sectors and rural communities. Among the objectives of the support is to preserve natural environments and habitats created and shaped by agricultural activities.[76]

F.3 Biofuel

The EU Climate Change Package obliges each Member State to increase the share of renewables in transport to 10%. As part of the package, sustainability criteria for biofuels have also been set.

The main measure for achieving the target in Finland is prescribing an obligation on fuel distributors in relation to biofuels that has been done in PUBTA. In 2020, the share of alternative fuels used in transportation was 12%, most of which consisted of biofuels.[77] Under the PUBTA (since 2011), fuel distributors must increase the distribution of biofuels gradually from 6% to 30% by 2029. The goal for distribution is 19.5% for 2022 and 21% for 2023. The intention behind the tougher national target set out in the PUBTA is that the Government has assumed that Finland will be able to take advantage of the double counting rules that apply to second generation biofuels.

In order to incorporate the sustainability criteria for biofuels and bioliquids, the Act on Biofuels and Bioliquids entered into force on 1 July 2013,[78] under which the Finnish Energy Authority is responsible for monitoring operators covered by the Act. Such operators must apply a sustainability system in order to verify that the biofuel or bioliquid in question is in line with the sustainability criteria.

Since 2011, all fossil fuels and biofuels are subject to an energy content tax based on the known heating value of the fuel, together with an emission content tax based on the carbon intensity of the fuel. Additionally, a quality scaling of the biofuels used in transportation has been introduced based on biofuels' fine particle emissions that are harmful to human health.

A new Act on Promoting the Use of Biofuel Oil (418/2019) took effect in 2019. The new act sets out an obligation to replace part of the light fuel oil used in heating, heavy duty machines, and fixed motors with biofuel oil.[79]

G. Climate change and sustainability

G.1 Climate change initiatives

Finland ratified the Paris Agreement in November 2016.[80] The LCES was originally adopted in 2008 and updated in March 2013. The LCES presents the main themes of the action plan which, among other things, are to reduce greenhouse gas ("GHG") emissions and increase the use of energy from renewable sources. In June 2015, a national Climate Change Act came into force.[81] The Climate Change Act sets a national target of reducing GHG emissions by 80% by 2050, compared to 1990 levels. A parliamentary strategy published by the Ministry of Economic Affairs and Employment in October 2014, ie Energy and Climate road map 2050, sets out means for reaching this target with regards to sectors not included in the EU ETS.[82]

The key targets and actions of Finland's LCES with respect to renewable energy include, among other things, the sustainable increase of the use of emission-free renewable energy, so that its share will rise to more than 80-95% by the end of 2030. The promotion of production and consumption of bioenergy is also a main focus area in the implementation of the strategy.

The Ministry of Economic Affairs and Employment together with the government of Finland prepared a new National and Climate Energy Strategy in 2022. The National Climate and Energy Strategy outlines measures by which Finland will meet the EU's climate commitments for 2030 and achieve the targets set in the Climate Change Act for reducing greenhouse gas emissions by 60 per cent by 2030 and being carbon neutral by 2035.[83] The new Government Programme includes many goals for mitigating climate change and developing a sustainable society. One of the biggest goals is to achieve carbon neutrality in Finland by 2035 and to update the Climate Change Act so that the goal can be achieved.[84]

Further, the current Government Programme aims to reduce the use of peat as an energy source so that the use of peat will be reduced by 50% by 2030.[85] On 1 January 2022, the Act on Excise Duty on Electricity and Certain Fuels (1260/1996, as amended) was amended and taxes on the use of peat became stricter. According to the amended provision in the Act, additional tax must be paid on use of peat if the sum of the market price of peat and the market price of emission rights is less than €18.63 per MWh.[86]

G.2 Emission trading

Legislation relating to emission trading in Finland consists of the Emission Trading Act ("ETA"), the Aviation Emission Trading Act, and the Act on the Use of the Kyoto Mechanism.[87]

The ETA applies to CO_2 emissions from industry sectors defined in the ETA; such industry sectors including, eg combustion installations, mineral oil refineries, coke ovens, and certain installations and processes of the steel, mineral, and forest industries. The ETA also applies to nitrous oxide emissions and perfluorocarbons from certain industry sectors as set out in the New EU ETS Directive.

If the ETA is applicable, the installation requires an emission permit that gives it the right to emit the relevant GHG into the atmosphere. The national emission trading authority of Finland, the EA, is responsible for issuing emission permits to installations that fall within the scope of the ETA.

For the trading period 2021-2030, the essential provisions and principles of the New EU ETS Directive relating to the total amount and allocation of allowances are provided for in the ETA. Under the ETA, relevant decisions of the Commission will be applied to the free allocation of allowances to installations from 2021 onwards.[88]

The auctioning of allowances (that are not allocated for free) takes place at an auction platform determined jointly by EU Member States and the Commission, and is carried out according to the Commission regulations on the auctioning of emission allowances. Finland has not opted out of the central auction platform for the auctioning of EU ETS credits. The revenues generated by the auction will be classed as income in the State's budget.

The ETA was amended in January 2014 to correspond with the rights under the New EU ETS Directive to convert Certified Emissions Reductions ("CERs") and Emission Reduction Units ("ERUs") to carbon credits in the 2013 to 2020 trading period.[89] Operators may request the EA to convert CERs and ERUs into emission rights, provided that CERs or ERUs do not originate from land use, changes in land use, forestry, nuclear power, or operations in which HFC-23 or nitrous oxide deriving from adipic acid production is decomposed. Further, the ETA was amended in 2019 to implement Directive (EU) 2018/410 of the European Parliament and of the Council of 14 March 2018, amending Directive 2003/87/EC to enhance cost-effective emission reductions and low-carbon investments, and Decision (EU) 2015/1814.

G.3 Carbon pricing

Currently, energy taxation is used as a way to promote the use of wood-based fuels, such as forest chips, in CHP production as well as in separate heat production and to reduce GHG emissions, particularly with respect to transportation. Notable items include the objectives that the use of coal in energy production will be phased out by 2030, and that the use of imported oil for domestic needs will be cut in half by 2030. The aim is to update the energy taxation in connection with the new climate strategy.[90]

As stated previously, state aid in the energy sector may currently be granted for certain investments or research of renewable energy projects.[91] The goal of the current government programme is to update state aid in the energy sector to support investments in energy technology. Also, the goal is to stop the use of coal by the end of 2029 and, accordingly, support companies that cease using coal in their operations.

G.4 Capacity markets

Fingrid, together with other Nordic TSOs, maintains a balancing energy market. The balancing capacity market was first introduced in 2016. In order to participate in the capacity markets, a balancing energy market contract entered into with Fingrid is needed.[92]

In the capacity markets, a reserve provider must give an amount of up regulating bids, which corresponds to accepted capacity bids, to the balancing energy market in exchange for a financial compensation. When necessary, the Nordic TSOs can activate bids on the balancing energy market during normal operation or disturbances. The activation is done from the Main Grid Control Center of Fingrid.[93]

H. Energy transition

H.1 Overview

At the end of 2021, Finland launched the Sustainable Growth Programme to support the green transition in Finland. The Sustainable Growth Programme will support growth that is in line with the aims of the Government Programme. The aim of the green transition is to improve energy efficiency and accelerate the transition to fossil-free transport and heating. The focus areas in the Sustainable Growth Programme are the promotion of, eg clean energy production, industrial circular economy solutions, and low-emission innovations.

In its third supplementary budget, the Government proposed to include €238 million in funding for the Sustainable Growth Programme. Overall funding of the Sustainable Growth Programme is €822 million. Half of the funding involved will be used to promote a green transition, and about a quarter will be for digitalisation.[94]

Together with the new National Climate and Energy Strategy for Finland , the Sustainable Growth Programme aims to achieve the goals set out in the current Government Programme.

H.2 Renewable fuels

Currently, there is no legislative or policy framework for hydrogen in Finland. However, Finland is working towards creating a national strategy that includes targets and objectives for the future development of the Finnish hydrogen economy. The current vision is that there will not be a separate hydrogen strategy, but the renewable fuel targets of Finland will be included in the revised climate strategy.

There are also ongoing initiatives and research projects relating to hydrogen. For example, at the beginning of 2021, the Finnish Government initiated a research project whose purpose is to extensively explore the opportunities opened up and the challenges posed by the hydrogen economy. The results of the project will be used in the preparation of the revised climate strategy, and in energy policy and energy technology in general. The research project was completed in March 2022. Also, the Ministry of Economic Affairs and Employment has decided to grant investment subsidies (€64.12 million in total) for four large renewable energy demonstration projects, two of which concern hydrogen.

In addition to the public sector, the private sector is also looking into the effects of the hydrogen economy. For example, the Finnish grid companies Fingrid and Gasgrid Finland have started a cooperation to explore the future development of the hydrogen economy, and what requirements the transition to hydrogen economy imposes on electricity and gas grid companies.

There are currently several hydrogen projects being developed in Finland and it is estimated that the production of hydrogen in Finland will significantly increase in 2025. The first green hydrogen production facility is being developed by PX2 Solutions to Harjavalta. The facility is already under construction and the construction works are expected to be finished during summer 2024.[95]

H.3 Carbon capture and storage

The implementation of the CCS Directive has been carried out in Finland by enacting the Act on Carbon Capture and Storage. In addition, the effective implementation of the CCS Directive in Finland has required a number of amendments to various acts and decrees, eg the Finnish Environmental Protection Act and the Decree on Environmental Protection. The implications of the CCS Directive were also noted when the new Waste Act was enacted in 2011. Based on current knowledge and technologies, there are no suitable geological areas in Finland for the final storage of CO_2. The Act on Carbon Capture and Storage bans the storage of CO_2 within Finnish territory and the Finnish exclusive economic zone ("EEZ"). There is an exception to the ban where CO_2 is stored for research purposes and the amount is 100,000 tonnes or less. The Act lays down rules and procedures for the capture and transmission of CO_2. The storage of carbon also requires an environmental permit.

H.4 Oil and gas platform electrification

According to the Government Programme, Finland aims to be the first carbon-neutral welfare society in the world. Therefore, for example, the use of oil in heating will be phased out by the start of the 2030s and oil heating will no longer be used in properties owned by the central government and local governments by 2024.

As a means to decrease the use of fossil fuels and increase electrification, the Government has prepared temporary electrification subsidies for energy-intensive industries in Finland. Under the subsidy scheme, some of the costs incurred from the EU's emission trading scheme and passed on in electricity prices will be compensated for a limited number of industries, such as forest, metal, and chemical industries, through an aid for the electrification of energy-intensive industries. Provisions on this scheme are laid down in the Act on Electrification Aid for Energy-Intensive Industries (493/2022)[96] and the scheme is valid for a fixed term of 2022–2026. The amount of subsidies to be paid will be determined, among other things, by the price of the emission allowances and the amount of electricity consumption or production of the operator.[97]

H.5 Industrial hubs/clusters/zones

EnergyVaasa is the largest energy technology cluster in the Nordic countries located in the Ostrobothnia region in Finland, the center being the city of Vaasa. The aim of EnergyVaasa is to develop sustainable technological solutions for the energy sector globally. About 160 operators are affiliated with EnergyVaasa and their combined revenue is about €5 billion per year. Those companies operate in many different sectors, which are needed to design, manufacture, market, and use the products as well as deliver them to customers. The largest companies included in EnergyVaasa are Wärtsilä and ABB. EnergyVaasa aims to invest about €1.2 billion in new technology solutions in the energy and infrastructure sectors by the end of 2025.[98] A new smaller energy cluster is currently being developed in North Savo. Currently, about 20 companies from the energy sector are involved in the development phase, but new companies are expected to join Energy Cluster North Savo as the project proceeds.[99]

There is no specific regulation in Finland regarding energy clusters, but if clusters are granted state aid, relevant rules and regulations must be complied with.

H.6 Smart cities

The six largest cities in Finland (Helsinki, Espoo, Vantaa, Tampere, Turku, and Oulu) have combined to develop a strategy for sustainable urban environments and evolving toward smarter cities. The project is called '6Aika' or the 'Six City Strategy'. 6Aika has carried out projects which have helped companies to develop new smarter services and operating models in order for municipalities in Finland to provide their services in a modern environment. The projects have concerned various themes, such as learning, circular economy, employment, and smart mobility. The cities involved in 6Aika have worked together with residents, companies and research, development and innovation organisations. 6Aika does not fund companies directly in their projects.

In the 2021, Smart City Index report, Helsinki was ranked sixth among 109 cities. In 2020, Helsinki ranked second.[100] Further, in 2020, Helsinki won the first prize among 400 cities and projects in the Digital Cities category at the global Year in Infrastructure Conference with its Digital City Synergy Project.[101]

There are no specific regulations in Finland regarding smart cities, but if smart city projects are granted state aid, relevant rules and regulations must be complied with.

I. Environmental, social and governance (ESG)

Finland does not have national legislation that addresses environmental, social, and governance issues in corporate law, banking or finance sectors. However, the Finnish Ministry of Economic Affairs and Employment and the Committee on Corporate Social Responsibility working under the ministry have been responsible for the judicial investigation and analysis of national regulations and legislation on corporate social responsibility ("CSR").[102]

The preparations for the national legislation on CSR lasted two years, however, in the spring of 2022 the preparations were paused due to political reasons.[103] Although there is no national legislation on CSR, different laws contain provisions that require companies to consider social and governance aspects related to their organisation or operations. Such laws are, for example, the Consumer Protection Act (38/1978), the Securities Markets Act (746/2012), the Investment Services Act (747/2012), and the Act on Mutual Funds (213/2019).

At the beginning of 2022, the Commission published a proposal for a Directive on corporate sustainability due diligence, also known as the EUs corporate social responsibility legislation.[104] Because the preparations of Finland's national legislation on CSR have now been put on hold, there has been discussion regarding whether Finland should wait for the EUs legislation and implement it as Finland's national CRS legislation. It has been argued that regulating CSR issues on an EU level would be more effective because all the large companies and other players would have the same rules and regulations to follow.[106]

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Energy law in France

Recent developments in the French energy market

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Renationalisation of Électricité de France (EDF)

The French Government, which already holds 83.9% of EDF, declared on 6 July 2022, it intends to renationalise EDF. Nationalisation would give the French Government more control over a revamp of the debt-laden group while contending with a European energy crisis. The French Minister of Economy, Mr. Bruno Lemaire is already working on this project with the European Commission.

In early July 2022, European Union lawmakers voted to allow natural gas and nuclear energy to be labelled as green investments (and have been included as part of the 'green taxonomy'[1]) removing the last major barrier to potentially billions of euros of funding from environmental investors.

This nationalisation could therefore be crucial regarding the government's project to build six additional EPR nuclear reactors as soon as possible.

Law no. 2022-1157 dated 16 August 2022, Amending Finance Act for 2022[2] provides for a dedicated part of the budget to be reserved to the potential acquisition by the French State of EDF's share capital which remain private to date – even if the provision of the Law is not as explicit on that point, we understand from the parliamentary debates that such part of the State's Budget would be dedicated to this purchase.

Extension of the demand response capacities

Article 24 of Law No. 2022-1158 dated 16 August 2022 on emergency measures to protect purchasing power, amends Article L. 431-6-2 of the Energy Code in extending to the gas supply network operators the ability to interrupt the consumption of 'certified' (*agréé*) final consumers connected to such distribution system network. Such interruption may occur, after a request from the gas transmission system operator, in those instances where the normal operation of the natural gas transmission networks is seriously threatened. The goal of this measure is the safeguard of the supply of protected consumers, subject to a compensation from the network operator to the final consumer whose consumption has been interrupted.

The awarding of contracts regarding demand-response capacities (*capacités d'interruption*) is carried out in France by means of calls for tenders conducted by the gas transmission system operator, pursuant to the proceeding detailed in Executive Order of 17 December 2019 (*Arrêté du 17 décembre 2019 relatif à l'interruptibilité de la consommation de gaz naturel*). The call for tenders allows to select the demand-response capacities likely to be contracted under a 'guaranteed demand response contract' (*contrat d'interruptibilité garantie*). Each consumer with a grid connection contract wishing to benefit from such guaranteed demand-response contract for one of its consumption points sends to the natural gas transmission system operator to which the plant is connected an offer.

Two orders drafts were examined on 8 September 2022 by the High Council of Energy (*Conseil Supérieur de l'Energie*), which aim at amending the order dated 17 December 2019 by facilitating the tender proceedings to contract demand-response capacities.

Introduction of an emergency and last resort supplier mechanism

Given the growing number of suppliers and increased competition in the field of gas and electricity supply, the need to ensure the continuity of supply for consumers and the end of regulated sales tariffs for natural gas, Law No. 2019-1147 of 8 November 2019 related to energy and climate[3] introduced a 'last resort natural gas supplier' (for customers who cannot find a supplier) and an emergency natural gas supplier (in the event of a supplier's failure) mechanisms.

Following a Ministerial Order dated 17 May 2018, the Ministry of Ecological Transition had designated four (4) suppliers of last resort for a period of three years.[4]

Decree No. 2021-273 dated 11 March 2021 related to natural gas and electricity supply specifies the procedures for designating such emergency and last resort suppliers. These suppliers are now designated for a period of five years[5] following a call for applications proceeding,[6] it is noted that the specifications are prior approved by the CRE.[7]

Following the last designation, in 2018, of resort suppliers, the designation of new suppliers of last resort according to the procedures provided by the above-mentioned decree was supposed to take place in spring 2022. However, these new suppliers had still not been designated in July 2022.

The designation of the emergency suppliers is currently underway and should take place soon,[8] the CRE having published a proposal for the specifications of the call for applications at the request of the Ministry of Ecological Transition by a decision dated 14 October 2021.[9]

A call for applications for the designation of natural gas suppliers has been issued. Candidates must submit their applications by 31 July 2022.[10]

In addition, with the increase in prices on the wholesale electricity markets, some suppliers risk being weakened. Thus, emergency suppliers have been designated in December 2021 to ensure continuity of supply for consumers in the event of a supplier's failure.[11]

The Conseil d'Etat validates two deliberations issued by the CRE approving the system operator – supplier model contract submitted by GRTgaz

By a decision dated 29 December 2021[12], the *Conseil d'Etat* recognised the CRE's jurisdiction (in accordance with paragraph 6 of Article L.134-3 and Article L. 111-92-1 of the Energy Code) to approve the contracts for access to the electricity distribution networks drafted template concluded between the public distribution system operators and the suppliers.[13]

The decision of the *Conseil d'Etat* considered that the CRE has duly exercised its regulatory jurisdiction in compliance with to the provisions of the Energy Code.[14]

Consequently:

- CRE is allowed to define a set of rules, especially regarding financial guarantee issued by the supplier, through a contract for access to the electricity distribution networks template.
- CRE may also, pursuant to Article 36 of the Directive dated 13 July 2009[15] and the second paragraph of article L. 131-1 of the Energy Code, require network operators to modify contracts in the course of their performance, when this modification is required to satisfy a sufficient reason of general interest pertaining to the public policy imperative of establishing effective and fair competition on the market.

However, CRE shall also be responsible for providing any transitional measures that may be necessary based on legal certainty principle (*principe de sécurité juridique*).

Prerogative of the ministry to enjoin to build up security gas reserves

Article 23 of Law no. 2022-1158 dated 16 August 2022 on emergency measures to protect purchasing power[16] adds an Article L. 421-7-2 to the French Energy Code, which authorises the Minister of energy to order, to the gas storage infrastructure operators, to build up security stocks of natural gas when the level of gas storage required to the suppliers (by Article L. 421-7 the French Energy Code) is not reached.

The operators shall use these security stocks only in those cases which will be described and detailed by decree, which has not been adopted yet.

Curtailment of gas fired power plants

Article 26 of the Law no. 2022-1158 dated 16 August 2022 on emergency measures to protect purchasing power provides that the Minister of energy is allowed to order to electrical plant operators (using natural gas power) to limit or suspend their plant activities and, if needed, to requisition the electrical power plant services in order to be operated according to dedicated directives and under the control of an operator (we understand a potential new operator) that the Minister appoints. Through such provisions, a new Article L. 143-6-1 has been inserted in the Energy Code detailing the modalities attached to such requirements, in case of serious threat to the security of natural gas supply.

End of regulated natural gas sales tariffs

Article 63 of Law no. 2019-1147 dated 8 November 2019 *relative à l'énergie et au climat* provides for the progressive end of regulated natural gas sales tariffs until 30 June 2023:

- from 1 December 2020, for non-domestic final consumers (except for sole owners of a residential building consuming less than 150MWh/year and syndicates of co-owners of such buildings); and
- from 1 July 2023, for domestic final consumers.

In a Communication dated 18 March 2021,[17] the CRE emphasised the slow pace of withdrawal from regulated natural gas sales tariffs and that, at this rate, there would still be 1.9 million domestic customers benefitting from the regulated natural gas sales tariffs on 30 June 2023. The CRE plans to identify the measures needed to accelerate regulated tariffs withdrawals in order to achieve the goals set by the Law no. 2019-1147 dated 8 November 2019 *relative à l'énergie et au climat*.

The situation in Ukraine and current inflation have impacted tariff regulation. The Finance Law for 2022 of 30 December 2021 provided, under Article 181,[18] that Engie's regulated gas tariffs will be blocked until 30 June 2022. But by an Order dated 25 June 2022, the Minister of Ecological Transition extended this freezing until 31 December 2022.[19]

Article 37 of Law No. 2022-1157 of 16 August 2022, Amending Finance Law for 2022 confirms the freezing of regulated gas tariffs until 31 December 2022.[20]

Without this freezing measure, the average level of regulated sales tariffs on 1 June 2022 would have been 54% (excluding taxes) higher than the level registered since 1 October 2021.

In addition, according to Article R. 445-4 of the Energy Code and as part of the measures of freezing as extended, several orders fixed the evolution of Engie's and local gas suppliers companies' sales tariffs as of 1 July 2022:

- Regarding Engie: its tariffs still remain frozen since 1 July 2022, at its level of the 1 October 2021.
- Regarding specifically the local distribution companies, it must be underlined that the applicable rules can differ:
  - For twelve of them, the tariffs applicable on 1 July 2022 remain at their frozen level in application of the 2022 Law of Finances for 2022.
  - One local distribution company is capped in its evolution on 1 July 2022 following the publication of the order extending the freezing of the rate.
  - For the nine others, the tariffs can evolve since 1 July 2022 but has to remain below the level of Engie's regulated gas sales tariffs.

Aid to companies affected by economic and financial consequences of the war in Ukraine to compensate the rise of power and gas prices

Decree No. 2022-967 dated 1 July 2022 sets up a one-time financial aid to those people and companies whose economic activity has been particularly affected by the consequences of the war in Ukraine.[21] In Order to obtain the aid, a request must be submitted online. The deadline for the submission is 19 August 2022 for the requests of aid for March to May 2022, and the 30 October 2022 for those related to the period June to August 2022. The aid is subject to a cap of either 2, 25 or

50 million depending on the economic situation of the person or company applying for the aid.

The following conditions must be filled in order to be eligible to the aid:

- the person applying for the aid must be a natural or legal person under private law, existing before the 1 December 2021, resident in France for tax purposes;
- it must engage in an economic activity which has been 'particularly affected' by the economic and financial consequences of the war in Ukraine;
- it must be a big energy consumer, meaning that expenses linked to the consumption of energy must represent at least 3% of 2021 total revenue;
- the increase of gas price endured by the requesting person must have been at least twofold the average price paid in 2021;
- the requesting person must not have engaged, as its main activity, in power or heat production, nor have acted as a credit or financial institution for one of the following three-month periods: (i) March to May 2022; (ii) June to August 2022;
- it must not find itself in a situation of conservation, legal redress or judicial liquidation, nor have any tax or social outstanding debts as of the 31 December 2021.

Draft bill to accelerate the construction of new nuclear facilities near existing nuclear sites[22]

On 27 September 2022, a draft bill to accelerate the construction of new nuclear facilities near existing nuclear sites was released.

The Draft will be discussed at the National Council for Ecological Transition on 5 October 2022. The aim of this law is to simplify the authorisation procedures for building nuclear power reactors projects located near existing nuclear sites.

The new provisions would be applicable to these projects in the vicinity of existing nuclear sites for which the application for authorisation provided for in Article L. 593-7 of the French Environmental Code is submitted within fifteen years of the promulgation of the law.[23]

Nuclear power reactor projects may fall within the qualification of general interest projects according to Article L. 102-1 of the French Urban Planning Code. In addition, such reactor projects can be qualified, by decree of the Council of State (*Conseil d'Etat*), as projects of general interest.

To allow the realisation of these projects, the bill provides for a simplified derogatory procedure of compatibility between the territorial coherence plan, the local town plan and the communal map with the project concerned. The bill also introduces a specific litigation procedure for disputes relating to the compatibility of urban planning documents with the projects.

Regulated access to nuclear energy: increase of the ARENH threshold

In a press release dated 13 January 2022, the Government announced measures to prevent electricity prices from escalating. To do so, it decided to supply an additional 20TWh of ARENH over the period from 1 April 2022 to 31 December 2022 at a price amounting €46.2/MWh. The decree no. 2022-342 dated 11 March 2022 precises for the new delivery period starting from 1 April 2022 the terms and conditions for the allocation of the additional nuclear electricity that can be sold.

The ARENH threshold will therefore reach a total of 120TWh in 2022. This measure is completed by a freeze on the Blue Tariff for business and residential customers until 1 February 2023 'so that the February 2022 increase is capped at 4% for these customer categories', according to EDF.

This re-capping of the ARENH has an even greater impact as it modifies the aid scheme approved by the European Commission in its decision of 12 June 2012.

Therefore, this modification shall be notified to the Commission. However, it seems that France and the Commission have agreed on the need to reform the current ARENH scheme, and that discussions are currently underway on this matter. Nevertheless, the outlines of the notification to the Commission of this modification are still unclear to date.

In a decision dated 5 May 2022,[24] the Conseil d'État rejected the claim introduced by several trade unions and shareholders of EDF for the suspension of the French Government's decision increasing the volume of electricity sold by EDF to its competitors at frozen tariff (AREHN). Among other things, the Conseil d'Etat considered that the measure was of public interest in the context of the energy crisis as it may allow to limit the electricity prices increase and rejected the claim for suspension.

ARENH and force majeure during Covid-19 crisis

Faced with the fall in electricity consumption, some suppliers have wished to renege on their commitments and have invoked force majeure event to reduce the volumes they purchased in November 2021 under the ARENH agreements. EDF considers that the conditions for applying the force majeure clause were not met.

In its deliberation, CRE indicates that in the absence of an agreement between the parties on the application of the force majeure clause, it would not reduce the ARENH volumes delivered by EDF to the suppliers concerned.

By a decision dated 17 April 2020,[25] the Conseil d'Etat following the CRE deliberation, rejected the claim as the emergency requirement was not fulfilled: the losses suffered by the suppliers were not sufficiently significant that they could have threatened the suppliers' viability.

However, in a decision dated 10 December 2021,[26] the Conseil d'Etat ruled that a clause foreseeing the application of the force majeure, when the event prevents the performance of the parties' obligations under reasonable economic conditions, is enforceable.

In such case, company had concluded a framework agreement on ARENH with EDF. But EDF refused to implement the force majeure clause provided for in the framework agreement. On 26 March 2020, the CRE restricting the application of the force majeure to a circumstance that makes it impossible to perform the obligation, rejected the application of the force majeure clause provided for in the agreement. The Conseil d'Etat granted company's request to invalidate the provisions of the CRE's decision excluding the application of this clause.

Mining code amendments

Four Ordinances dated 13 April 2022 amended the Mining Code:

- The French environmental Code has been modified to include the mining operation to the regime of Environmental authorisation previously created to the 'ICPE';[27]
- the system related to the compensation for the damages caused by a mining activity was clarified and strengthened. From now on, health and environmental damages will be included in the mining damages' scope;[28]
- the procedures created to obtain a mining authorisation have been modified to take into account environmental, competition and democratic issues. The Government imposes the mining operator to respect several obligations in order to apply for a mining title[29]; and
- special procedures applying to overseas Department of France mostly related to the protection of the environment were set up.[30]

Renewable energy: Law no. 2020-1721 dated 29 December 2020, Finance Law for 2021[31]

In 2020, the French Government decided to renegotiate the applicable solar feed-in-tariff for certain Power Purchase Agreements ("PPAs").

Article 225 of Finance Law for 2021 provides for a reduction of the feed-in-tariff of PPAs for the production of energy from solar power sources, entered into between 2006 and 2010 (ie, PPAs executed pursuant to Orders of 10 July 2006, 12 January 2010 and 31 August 2010).

Decree no. 2021-1385 of 26 October 2021 and Ministerial Order of 26 October 2021 sets the rules to determine the new feed-in-tariffs.

The reduction applies to all projects with an installed capacity of more than 250 kW, independently from the kind of technology used (either photovoltaic or thermodynamic).

The provision puts in place certain safeguard mechanisms, in order to reduce the impacts of the tariff reduction on producers:

- The reduction must consider the tariff order applicable to the installation, the technical characteristics of the installation, its location, its date of commissioning, its conditions of operation.
- The total return on fixed capital, resulting from the accumulation of all the revenues from the installation and the financial or tax aid granted for it must not exceed a reasonable return on capital, taking into account the risks inherent to the operation.

Furthermore, producers negatively affected by the tariff reduction can request the Minister of Energy to grant them a higher feed-in-tariff when the reduced one would jeopardize their economic viability. In a deliberation no. 2022-161 of 16 June 2022, CRE set out the guidelines to be applied to assess the aforementioned requests.

Law no. 2021-1104 dated 22 August 2021 on tackling climate change and increasing resilience to its effects ("Climate and Resilience Law")[32]

The Climate and Resilience Law extends the obligation to install renewable energy systems on certain buildings and their parking areas as from 2023. In order to achieve the objectives of the PPE, the Climate and Resilience Law reinforces the obligation to install renewable energy production systems on buildings by providing that outdoor car parks of more than 500m^2 associated with buildings subject to the above-mentioned obligation, as well as new car parks of more than 500m^2, must incorporate vegetation or shaded areas with a renewable energy production system covering at least half of their surface. As from 1 July 2023, applications for construction or development and to the conclusion of new public service concession, service provision or commercial lease contracts relating to the management of a car park, or its renewal permits will be subjected to this obligation.[33]

Measures concerning the most polluting vehicles

The Climate and Resilience Law also provides for the end of the sale, by 1 January 2030, of new passenger cars emitting more than 123 grammes of carbon dioxide per kilometre according to the WLTP standard. Additionally, it sets a target of ending the sale of new heavy-duty vehicles used to transport people or goods and using mostly fossil fuels by 2040. Furthermore, advertising for the most polluting vehicles will be prohibited from 2028.

Measures concerning rail and air transport

The Climate and Resilience Law prohibits domestic air flights when a rail alternative exists in less than 2.5 hours. Airlines operating flights in metropolitan France will be required to offset the emissions from these flights: 50% of emissions will be offset in 2022, 70% in 2023 and 100% in 2024. This obligation is applicable to airlines operating flights within the national territory whose greenhouse gas ("GHG") emissions are subject to the obligations of the European Emissions Trading Scheme established by Directive 2003/87/EC of the Parliament and of the Council of 13 October 2003 establishing a scheme for GHG emission allowance trading within the Union. In addition, projects to extend or create a new aerodrome cannot be declared to be in the public interest if they lead to an increase in GHG emissions. However, exceptions are provided for certain aerodromes such as Nantes-Atlantique, Basel-Mulhouse, heliport, as well as for projects 'made necessary by health, safety, national defence or regulatory standards'. France will also support the development of passenger rail transport in order to achieve the objectives of increasing the modal share of rail transport by 17% in 2030 and 42% in 2050. The Law also includes the objective to double the modal share of rail freight in domestic goods transport by 2030.

Offshore wind farms

The Climate and Resilience Law sets the target of an additional 1 GW per year from 2024 for offshore wind farms.[34]

Decree no. 2018-112 of 16 February 2018 amending Decree no. 2016-691 of 28 May 2016 defining the lists and characteristics of the installations mentioned in Articles L. 314-1, L. 314-2, L. 314-18, L. 314-19 and L. 314-21 of the Energy Code[35]

Entitlement to continue benefiting from the purchase obligation

Pursuant to Decree no. 2016-691 dated 28 May 2016, producers of electricity from solar plants can continue to benefit from the purchase obligation under the ministerial order dated 4 March 2011, provided that a complete grid connection request has been filed before the entry into force of Decree dated 28 May 2016 (ie 30 May 2016) and these plants are completed before the later of the two following dates: (i) 18 months from the date of a complete grid connection request or (ii) 18 months from the entry into force of Decree dated 28 May 2016 (ie 30 May 2016).

The Decree no. 2018-112 of 16 February 2018 extends the above time limits in (i) to keep benefiting from the purchase obligation by an additional 18-month period for solar plants which output is below 9Kwh.

Pursuant to Decree no. 2016-691 dated 28 May 2016, producers of electricity from biogas plants could continue to benefit from the purchase obligation under the ministerial order dated 19 May 2011 provided that a complete grid connection request has been filed within three months from the acknowledgement of receipt issued by the ADEME certifying that a complete identification file has been received and these plants are completed before the later of the two following dates: (i) two years from the date of a complete purchase contract request or (ii) 18 months from the entry into force of Decree dated 28 May 2016 (ie 30 May 2016).

The Decree no. 2018-112 of 16 February 2018 extends the above time limits in (i) to continue benefiting from the purchase obligation by an additional two-year period for biogas plants. This Decree also clarifies the definition of 'completion' regarding gas cogeneration installations. Such completion is defined as the complete construction of equipment (for new plants) or the implementation of the full investment plan (for renovated plants) and does not include the completion of the electricity and gas grid connection works which resort to the relevant grid operators' responsibility.

Extension of the list of installations entitled to benefit from a premium regime

In accordance with the provisions of the Decree dated 19 February 2018,[36] producers of electricity from solar plants whose output is comprised between 500kWh and 12MWh are entitled to benefit from the premium regime set out in the ministerial order dated 4 March 2011 provided that a complete grid connection request has been filed between 1 January 2016 and 30 May 2016.

Decree no. 2018-222 dated 30 March 2018 establishing the compensation scheme in case of expiration of the term for the connection to the public power transmission system of an offshore wind power plant whose price is paid by the transmission system operator and in case of damage or dysfunction affecting the onshore or offshore connection works.

Compensation of grid connection costs for offshore-wind projects by RTE

To allow faster implementation of marine renewable energy projects and to reduce their costs, the recently enacted Hulot Law[37] (and one of its implementing Decree no. 2018-222 dated 30 March 2018)[38] have introduced new provisions in the Energy Code providing for an allocation of grid connection costs between the energy producer and the electricity transmission grid operator, RTE.

Under the new provisions,[39] RTE shall bear the grid connection costs relating to all offshore-wind projects awarded under a competitive tender procedure when the energy producer has had no choice in the location of the offshore wind project, including the stranded costs incurred in the situation where the tender procedure would be abandoned. Such costs shall however be incurred by the offshore wind project developer in case the latter withdraws during the implementation of the project.

In addition, the Energy Code now also provides that RTE shall compensate offshore wind project developers for any delay in delivering the grid connection by the date set in the tender documentation. Such indemnification is due except in situations where the delay results from a force majeure event or an event attributable to the project developer. The amount of such indemnification is calculated in accordance with the provisions of Decree no. 2018-222 dated 30 March 2018 (codified in the Energy Code) and such indemnification is granted on a monthly basis and is due as sole remedy.[40]

Finally, the Energy Code also provides that RTE shall compensate offshore wind project developers for any damage or malfunction attributable to RTE and affecting the grid connection onshore or offshore facilities if such damage or malfunction results in a curtailment. The amount of the indemnification depends on (i) the date of occurrence of the curtailment and (ii) the number of days of curtailment. Such indemnification is granted on a monthly basis and is due as sole remedy.[41]

The first project that will benefit from the above rules will be the offshore wind farm project located in Dunkirk.

Confirmation of the Decree relating to electricity self-consumption

By a decision dated 26 July 2018,[42] the *Conseil d'Etat* rejected the claim brought by the associations *Vent de Colère! Fédération nationale et Fédération environnement* seeking the cancellation of Decree no. 2017-676 of 28 April 2017 relating to self-consumption of electricity. Decree no. 2017-676 notably entitles small scale producers of electricity from onshore wind sources to benefit from a premium aid scheme (provided that their installation if made up of a maximum of 6 turbines, each of 3MW maximum). The *Conseil d'Etat* rejected the claim on the following grounds:

- first, the *Conseil d'Etat* considered that the provisions of EU Directive 2009/72/EC of 13 July 2009 do not require that the implementation by a Member State of aid measures benefiting to installations producing electricity from renewable energy sources be preceded by an assent (*avis conforme*) of the CRE;
- second, the *Conseil d'Etat* considered that, insofar as Decree dated 28 April 2017 does not create an aids scheme that

would be enforceable without any further implementing measures, there was no obligation to notify such Decree to the European Commission;

- third, the *Conseil d'Etat* considered that the decision of the European Commission dated 5 May 2017, which considered that the aid scheme created under Decree dated 28 April 2017 was compatible with the European market, was compliant with the Energy Guidelines.[43]

Regulatory measures for the support of renewable energies

On 28 July 2022, the Ministry for Energy Transition announced a series of emergency measures intended to respond to the urgency of the situation.[44]

In order to implement these measures, an Order was issue dated 28 July 2022 concerning the purchase terms and conditions for power produced by photovoltaic plants located on buildings, hangars or shade houses whose power is equal or lower than 500kW.[45] On 30 August 2022, the CRE updated its rules and technical specifications applicable to renewable energies call for tenders in order to implement the other regulatory measures announced by the Ministry.[46]

In application of these measures:

- Producers of renewable electric energy that are party to a contract for difference will be authorised to sell their electricity on markets, for a period of eighteen months, before their contracts are performed.
- The anticipated reduction of tariffs for photovoltaic projects on buildings will be suspended for the year 2022.
- All projects that win tenders will be allowed to increase their power by up to 40%, without justification, before their completion.
- The increase in the cost of materials will be taken into account for all future renewable electricity production projects, such as biomethane production.
- The commissioning deadline for biomethane production facilities that have obtained their environmental authorisation will be extended. With regard to the last two points about biomethane, on 23 September 2022 the Ministry for the Ecological and Energy Transition announced the imminent adoption of two regulatory measures to implement such measures.

Bill for the acceleration of renewable energies and proposed regulation by the Ministry for the energy transition

The adoption of a bill intended to boost the deployment of renewable energies (the bill for the acceleration of renewable energies)[47] was announced by the French Government in July 2022.

A first draft was then submitted to the national Council for the energy transition (*Conseil national de la transition énergetique*) as part of a preliminary public consultation, as well as to the *Conseil d'Etat* for advisory opinion on 8 August 2022.

On 26 September 2022, the *Conseil d'Etat* published its advisory opinion[48]; on the same day, the bill was submitted to the Ministries Council to be discussed before it is presented to the Parliament.

The bill aims to accelerate the development of renewable energy projects while at the same time increasing their acceptance from local populations.

The bill focuses on four main pillars:

- simplification of the administrative procedures required to authorise the realisation of a project of production of renewable energy.;
- mobilisation of lands that has already been artificialised (such as car parks, degraded land or highways) as suitable land for the development of renewable energy projects;
- simplification of the legal framework applicable to the realisation of offshore wind projects, by involving citizens as early as possible in the choice of the location of the project; and
- provision for local residents and municipalities to benefit from the value and economic benefits of renewable energy plants. A framework is also detailed allowing for the development of direct contracts between energy producers and consumers.

Among the measures proposed in the bill there is also the simplification of administrative proceedings to connect the project to the grid and the simplification of the procedure required to amend local land use planning documents in order to make them compatible with renewable energy projects.

As of today, the bill has not been adopted yet and it is not sure whether it will be approved as it currently is by the French parliament.

CRE deliberation no. 2022-202 of 13 July 2022 on the assessment of energy public service costs for 2023

Article L. 121-9 of the Energy Code entrusts the CRE with the task of assessing the costs of the public service of energy once a year. In 2022, the results of the assessment have been published on 13 July by means CRE deliberation no. 2022-202.[49]

The assessment consists in estimating the expenses the French State bears in order to support and subsidise renewable energies for the production of electricity and gas (the energy public service charges).

In its 2022 assessment, the CRE found for the first time that in 2022 and 2023, the charges to be sustained to finance the energy public service have been and will be negative – meaning that costs sustained by the State in the context of feed-in-tariff PPAs and contracts for difference are lower than the value of the energy on the marketplace.

This overall result was mostly made possible by onshore wind projects, whose energy production is high for a relatively low average unit cost. Solar power, on the contrary, still represents a cost for the French State, due to the expensive historic PPAs.

In this context, in order to avoid a windfall effect on producers benefitting from Feed-in Tariff ("FiT") PPAs and contracts for difference ("CFDs"), the CRE has issued the following recommendations for the Government:

- The permanent suspension of the cap established in favour of producers that are part to a CFD. This cap currently allows producers to reimburse only partially the State for the profit they make by selling the energy they produce on the market, compared with an established benchmark price.
- The introduction of a special tax for those producers that terminate their FiT PPAs or CFDs without paying any penalty or indemnity to the State, and without reimbursing the State of the aid perceived, thanks to advantageous regulations in place when they concluded their FiT PPAs or CFD.

If such recommendations were to be heeded by the Government, producers in CFD currently benefitting of a cap would see their profits significantly reduced. At the same time, it would become more expensive and less advantageous for producers to terminate the FiT PPA or CFD they are part to in order to switch toto produce either for the storage of non-hazardous waste or for the digester methanation of non-hazardous products or waste.

The call for tender will be implemented throughout three phases until December 2023. During the first phase, lasting until the end of December 2022, purchase agreements will be concluded for a total power of 500GWh HHV/year.

Biofuels: Decree no. 2022-1120 dated 4 August 2022 related to crops used to produce biogas and biofuel

Decree no. 2022-1120 dated 4 August 2022[50] modifies Article D. 543-291 of the Environment Code by specifying the definition of 'main crops' and 'intermediate crops' used in the context of incentive taxes for biofuel.

Under the new definitions, main crops must comply with at least one out of five requirements, namely:

- being the only crop on a given plot of land throughout a year;
- being declared as main crop in a request for State aide under the common agricultural policy;
- being cultivated on a plot of land that has not been the subject of a request for a State aide under the common agricultural policy;
- being cultivated on the plot on the 1 June of the relevant year pursuant to climatic singularities and cultural practices;
- being qualified as a perennial crop pursuant to Article L. 411-9-11 of the Rural Code.

Intermediate Crops are defined as those crops that are cultivated in the European Union without being main crops, and that are planted sown and gathered on a plot of land located between two main crops.

Decree no. 2022-1102 removes any distinction between nutritional crops and energy crops. It also removes all exceptions to the 15% limit of supply by main crops that applies to biogas facilities.

Capacity market: CRE approved new rules for the capacity mechanism

On 16 December 2021, the CRE adopted three deliberations on the capacity mechanism, including deliberation no. 2021-371 giving its opinion on the draft rules of the capacity mechanism.

RTE submitted, for opinion, on 29 November 2021 a draft set of rules (known as "v4 rules") which constitutes the third major revision of the capacity mechanism rules which came into force on 22 January 2015.

This proposal comes after a report published by RTE in August 2021 on the first three years of delivery of the capacity mechanism. This report identified several areas for technical improvement and simplification of the mechanism.[51]

The main amendments proposed by RTE and approved by the CRE can be classified into the following five themes:[52]

- making the mechanism easier to understand;
- improving the efficiency of the mechanism with regard to its objectives;
- facilitating the day-to-day handling of the mechanism by the stakeholders;
- reducing the financial burden on participants in the mechanism;
- ensuring the compliance of the mechanism with the European regulatory framework.

In addition, on 28 April 2022, the CRE adopted a deliberation no. 2022-119 aiming to propose an order related to assignment modalities of ARENH capacity guarantees, according to Article R. 335-69 of the French Energy Code.

Energy transition: renewable fuels (hydrogen and ammonia)

Developing a more mature market: Calls for tenders, for projects and investments

Calls for tenders and for projects and other Government investments have recently been announced pursuant to the 2020 National Hydrogen Strategy or is otherwise ongoing pursuant to the former 2018 Hydrogen Plan.

In 2020

The French public agency for ecological transition (ADEME) launched a series of calls for proposals in October 2020: The 'Hydrogen Territorial Ecosystems' call for proposals, for investing in regional hydrogen vehicle 'eco-systems' projects (hydrogen vehicles and associated hydrogen fuelling station, on a regional and a local level).

ADEME has issued a call for projects by consortia composed of local authorities and suppliers providing hydrogen solutions, hydrogen uses on a regional and local scale. ADEME's budget for this call was of €275 million until 2023.[53]

The 'Technological bricks and hydrogen demonstrators' call for proposals, for developing new and improved components and systems related to the production and transport of hydrogen and its uses (which can be factored into France's hydrogen supply chain). This project has a budget of €350 million until 2023.[54]

In 2021

The Ministry of Economy, Finance and Recovery has also announced that France planned to set aside a financial allocation of €1.5 billion for the construction of a major project of European interest on hydrogen.[55]

In 2022

A call for interest as part of the Priority Research Programme ("PPR") 'hydrogen applications' operated by the National Research Agency ("ANR") has been launched. This PPR will support upstream research and prepare the future generation of hydrogen technologies (batteries, tanks, materials, electrolysers, etc). It will be endowed with €65 million.[56]

A call for tenders in the framework of the support mechanism to produce decarbonated hydrogen, by remuneration complement will be launched.[57]

Natural hydrogen

On 13 April 2022, the French Government published four Orders amending the Mines Code, pursuant to Article 81 of Law no. 2021-1104 dated 22 August 2021 on tackling climate change and increasing resilience to its effects.[58]

One of the aforementioned orders, Order no. 2022-536,[59] adds natural hydrogen (ie, hydrogen found in nature as a free gas, sometimes in layers of the continental crust) to those substances that are subject to mines regulation, meaning that any exploration and extraction works regarding natural hydrogen will have to undergo a specific permitting and concession proceeding set out in the Mines Code, starting from 1 January 2024.

Endnotes

1. European Union taxonomy designates a classification of economic activities considered as having a favourable impact on the environment (sustainable activities). On, 11 July 2022, the Complementary Climate Delegated Act to accelerate decarbonisation related to EU taxonomy has been updated.
2. In French: Loi n° 2022-1157 du 16 août 2022 de finances rectificative pour 2022.
3. *Loi n°2019-1147 du 8 novembre 2019 relative à l'énergie et au climat*: www.legifrance.gouv.fr/loda/id/JORFTEXT000039355955.
4. Ministerial Order dated 17 May 2018 related to the designation of suppliers of last resort: www.legifrance.gouv.fr/jorf/id/JORFTEXT000036932142.
5. Articles R.442-21 (for last resort suppliers) and R.443-36 (for emergency suppliers) of the Energy Code respectively introduced by Articles 30 and 31 of Decree No. 2021-273 dated 11 March 2021 (*relatif à la fourniture de gaz naturel et d'électricité*).
6. Articles R.443-14 (for last resort suppliers) and R.443-28 (for emergency suppliers) of the Energy code respectively introduced by Articles 30 and 31 of Decree No. 2021-273 dated 11 March 2021 (*relatif à la fourniture de gaz naturel et d'électricité*).
7. Articles R.443-14 (for last resort suppliers) and R.443-28 (for emergency suppliers) of the Energy code respectively introduced by Articles 30 and 31 of Decree No. 2021-273 dated 11 March 2021 (*relatif à la fourniture de gaz naturel et d'électricité*).
8. See www.ecologie.gouv.fr/fourniture-denergie-ministere-designe-des-fournisseurs-secours-en-electricite-assurer-titre.
9. CRE, *Délibération n°2021-315 du 14 octobre 2021 de la Commission de régulation de l'énergie portant proposition de cahiers des charges des appels à candidatures portant sur la désignation de fournisseurs de secours en gaz naturel et en électricité*, 14 October 2021.
10. See www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=&ved=2ahUKEwjZyZnh3pP5AhX7hM4BHUO9BWYQFnoECBEQAQ&url=https%3A%2F%2Fwww.cre.fr%2Fmedia%2FFichiers%2Fpublications%2Fappelsoffres%2Ffourniture-de-secours-en-gaz-naturel-telecharger-le-cahier-des-charges-en-vigueur&usg=AOvVaw1219X6upMty2vS-sYvm8LZ.
11. See www.ecologie.gouv.fr/fourniture-denergie-ministere-designe-des-fournisseurs-secours-en-electricite-assurer-titre.

12. CE, 29 December 2021, Aff. Société Joul, n° 437594 and 443328, rec. Lebon.
13. CRE, Deliberation n°2020-169 dated 25 June 2020 from the Energy regulation commission (*Délibération portant approbation du modèle de contrat d'accès aux réseaux publics de distribution d'Enedis pour les points de connexion en contrat unique*).
14. In French, extract of the decision: "*en définissant un ensemble de règles, notamment en ce qui concerne la garantie financière à la charge du fournisseur, sous la forme d'un modèle de contrat relatif à l'accès au réseau public de distribution pour les points de connexion en contrat unique, la Commission de régulation de l'énergie a exercé la compétence réglementaire dont elle dispose en application des dispositions du 3° de l'article L. 134-1 du code de l'énergie. La société Joul n'est donc pas fondée à soutenir que la commission aurait méconnu sa propre compétence.*"
15. Directive 2009/72/EC of the European Parliament and of the Council of 13 July 2009 concerning common rules for the internal market in electricity and repealing Directive 2003/54/EC.
16. In French "*Loi n° 2022-1158 du 16 août 2022 pour la protection du pouvoir d'achat*".
17. CRE, *Délibération n° 2021-84 de la Commission de régulation de l'énergie du 18 mars 2021 portant communication sur le déroulé des échéances relatives à la fin partielle des tarifs réglementés de vente d'électricité et à la suppression des tarifs réglementés de vente de gaz naturel*, 18 March 2018.
18. Article 181 of Law No. 2021-1900 dated 30 December 2021 (*portant Loi de finances pour 2022*).
19. Ministerial Order dated 25 June 2022 (*modifiant la date de fin de gel des tarifs réglementés de vente du gaz naturel*).
20. *Loi n° 2022-1157 du 16 août 2022 de finances rectificative pour 2022*: www.legifrance.gouv.fr/jorf/id/JORFTEXT000046186661.
21. Decree no. 2022-967 dated 1st July 2022 (*instituant une aide visant à compenser la hausse des coûts d'approvisionnement de gaz naturel et d'électricité des entreprises particulièrement affectées par les conséquences économiques et financières de la guerre en Ukraine*).
22. See for more details (in French only): *Avant-projet de loi visant à accélérer la construction de nouvelles installations nucléaires à proximité de sites nucléaires existants*.
23. Article 1 of the preliminary draft.
24. Decision Conseil d'Etat, 5 May 2022, no. 462841.
25. Decision Conseil d'Etat, 17 April 2020, no. 439949.
26. Decision Conseil d'Etat, 10 December 2021, no. 439944.
27. *Ordonnance n° 2022-534 du 13 avril 2022 relative à l'autorisation environnementale des travaux miniers* www.legifrance.gouv.fr/jorf/id/JORFTEXT000045570510.
28. *Ordonnance n° 2022-535 du 13 avril 2022 relative au dispositif d'indemnisation et de réparation des dommages miniers* www.legifrance.gouv.fr/jorf/id/JORFTEXT000045570527.
29. *Ordonnance n° 2022-536 du 13 avril 2022 modifiant le modèle minier et les régimes légaux relevant du code minier* www.legifrance.gouv.fr/jorf/id/JORFTEXT000045570540.
30. *Ordonnance n° 2022-537 du 13 avril 2022 relative à l'adaptation outre-mer du code minier* www.legifrance.gouv.fr/jorf/id/JORFTEXT000045570578.
31. Law no. 2020-1721 of 29 December 2020, Finance Law for 2021. See www.legifrance.gouv.fr/loda/article_lc/LEGIARTI000042778827.
32. Law no 2021-1104 dated on 22 August 2021 on tackling climate change and increasing resilience to its effects called "climate and resilience law". See www.legifrance.gouv.fr/jorf/id/JORFTEXT000043956924.
33. Art. L. 111-19-1 of Town planning code and art. 101 of climate and resilience law.
34. Art. 93 of climate and resilience law.
35. Decree no. 2018-112 of 16 February 2018 amending Decree no. 2016-691 of 28 May 2016 defining the lists and characteristics of the installations mentioned in Articles L. 314-1, L. 314-2, L. 314-18, L. 314-19 and L. 314-21 of the Energy Code. See www.legifrance.gouv.fr/eli/decret/2018/2/16/TRER1734899D/jo/texte.
36. Decree no. 2018-115 dated 19 February 2018 *complétant la liste des installations pouvant bénéficier du complément de rémunération en application de l'article L. 314-18 du code de l'énergie*.
37. Law no. 2017-1839 dated 30 December 2017 *mettant fin à la recherche ainsi qu'à l'exploitation des hydrocarbures et portant diverses dispositions relatives à l'énergie et à l'environnement*.
38. Decree no. 2018-222 *fixant le barème d'indemnisation en cas de dépassement du délai de raccordement au réseau public de transport d'électricité d'une installation de production d'électricité à partir de sources d'énergie renouvelable implantées en mer dont le coût est supporté par le gestionnaire de réseau et en cas d'avarie ou de dysfonctionnement affectant la partie terrestre ou maritime des ouvrages de raccordement des installations de production en mer.*
39. Article L. 342-7 of the Energy Code.
40. Articles L. 342-3 and D. 342-4-12 of the Energy Code.
41. Article L. 342-7-1 and D. 342-4-13 of the Energy Code.
42. Decision of the Conseil d'Etat dated 26 July 2018 no. 411919.
43. Guidelines on State aid for environmental protection and energy 2014-2020, no. 2014/C 200/01.
44. See www.ecologie.gouv.fr/agnes-pannier-runacher-annonce-des-mesures-durgence-accelerer-developpement-production-denergies#:~:text=Ces%20mesures%20consistent%20%C3%A0%20%3A,d'effet%20de%20leurs%20contrats.
45. Order dated 28 July 2022 amending Order date 6 October 2021 establishing the power purchase conditions for electricity produced by photovoltaic plants located on buildings, hangars or shadehouses whose power is equal or lower than 500kW mentioned by Article D. 314-15 of the Energy Code and located in mainland France. See www.legifrance.gouv.fr/jorf/id/JORFTEXT000046113790.
46. See www.cre.fr/Actualites/la-cre-publie-des-cahiers-des-charges-adaptes-afin-d-accelerer-le-deploiement-des-energies-renouvelables-en-france.
47. Bill for the acceleration of renewable energies, no. ENER2223572L. See www.legifrance.gouv.fr/dossierlegislatif/JORFDOLE000046329719/?detailType=CONTENU&detailId=1.
48. CE advisory opinion of 26 September 2022. See www.conseil-etat.fr/avis-consultatifs/derniers-avis-rendus/au-gouvernement/avis-sur-un-projet-de-loi-relatif-a-l-acceleration-des-energies-renouvelables.
49. CRE deliberation dated 13 July 2022 on the assessment of energy public service costs for 2023. See www.cre.fr/Documents/Deliberations/Decision/evaluation-des-charges-de-service-public-de-l-energie-pour-2023.
50. Decree no. 2022-1120 dated 4 August 2022 related to crops used for the production of biogas and biofuel. See www.legifrance.gouv.fr/jorf/id/JORFTEXT000046144291.
51. Article 1 of the Deliberation no. 2021-370 of 16 December 2021 giving an opinion on the draft rules of the capacity mechanism.
52. Article 2 of the Deliberation no. 2021-370 of 16 December 2021 giving an opinion on the draft rules of the capacity mechanism.
53. ADEME, Call for proposals 'Hydrogen Territorial Ecosystems', September 2020.
54. ADEME, Call for proposals 'Technological bricks and hydrogen demonstrators', October 2020.
55. Ministry of Economy, Finance and Recovery, Presentation of the national strategy for the development of low-carbon hydrogen in France, 8 September 2020.
56. National Research Agency, Priority Research Programme and Equipment (PRPE) for decarbonised hydrogen, 24 January 2022.
57. Ministry of Economy, Finance and Recovery, Presentation of the national strategy for the development of low-carbon hydrogen in France, 8 September 2020.
58. Law no. 2021-1104 dated 22 August 2021 on tackling climate change and increasing resilience to its effects.
59. New article L. 111-1 of the Mines Code, as amended by Ordonnance no. 2022-536 dated 13 April 2022 amending the mines model and the regulatory framework set out by the Mines Code.

Overview of the legal and regulatory framework in France

A. Electricity

A.1 Industry structure

Background

Between 1946 and 2000, electricity generation, transmission, distribution and supply were carried out by the historical operators: EDF and the non-nationalised distributors (*distributeurs non nationalisés* or "DNN").

The First and Second Electricity Directives were transposed into French law by:

- Law 2000-108 of 10 February 2000, on the public service of electricity (Law 2000-108);[1]
- Law 2003-8 of 3 January 2003, on gas and electricity markets and the public service of energy;[2]
- Law 2004-803 of 9 August 2004, on electricity and the public service of gas and electricity and gas companies (Law 2004-803);[3]
- Law 2006-1537 of 7 December 2006, governing the energy sector;[4] and
- Law on the new organisation of the electricity market enacted on 7 December 2010 (NOME Law)[5] with a view to developing competition in the French electricity market.

The French government has adopted by *ordonnance* No. 2011-504 of 9 May 2011 (Ordinance 2011-504),[6] the legislative part of the French energy code (Energy Code), which entered into force on 1 June 2011 and codified several laws, in particular the above-mentioned laws, as well as the Third Electricity Directive.

The Energy Code has three substantial contributions:

- the law No. 2013-312 of 15 April 2013[7] (Brottes Law) entrusts the Energy Regulation Commission (*Commission de régulation de l'énergie* or CRE) with the enforcement of the REMIT,[8] implements simplification measures regarding the support regime of wind farms and other modifications to the rules regarding the energy sector;[9]
- the regulatory part of the Energy Code adopted by decree on 30 December 2015[10]; and
- ahead of the United Nations Framework Convention on Climate Change (COP 21) hosted by France in December 2015, the law No. 2015-992 of 17 August 2015 has been issued to set out the national policy for implementing the energy transition in France (the "Energy Transition Law").[11] Numerous implementing decrees have been adopted in the wake of this law.[12]

The Energy Transition Law defines some very challenging targets for the French energy sector,[13] including (we indicate in brackets the goals that could be amended by a draft bill to be discussed in 2019, in the wake of the Draft PPE (as defined and detailed below):

- a 50% reduction in energy consumption by 2050 with an intermediary objective of a 20% reduction by 2030;
- a 30% reduction in fossil fuel consumption by 2030;
- an increase in the use of renewable energy to cover 23% of the French gross final electricity consumption by 2020 and 32% by 2030 (18.7% of the gross final electricity consumption in 2015); and
- a reduction in the share of electricity produced from nuclear power to 50 % by 2025 (76.3% of the national electricity production in 2015).

The postponement to 2035 of this last objective regarding a decrease of the share of nuclear energy had been announced in 2017 by the former minister in charge of energy, Mr Nicolas Hulot.

The Energy Transition Law introduces a multiannual programming of energy (*programmation pluriannuelle de l'énergie*, called "PPE").[14] It has been designed as a global and comprehensive program which covers all types of energy, security of supply, energy storage, and networks.

The PPE sets out the priorities regarding the management of all types of energy on the French territory in order to reach the objectives defined in the Energy Code,[15] especially energy efficiency.

The first PPE for mainland France has been implemented by decree No. 2016-1442 dated 27 October 2016[16] and covers two sets of periods (2016-2018 and 2019-2023) with an adjustment in 2018 and then every five years thereafter.[17] Dedicated PPEs apply for Corsica,[18] Mayotte,[19] Guadeloupe,[20] French Guiana[21] and Réunion.[22] An adjustment to the PPE for the period 2019-2023 and the new objectives for the period 2024-2028 will be published in 2019 and a finalised draft has been made public on 25 January 2019 (the "Draft PPE").[23]

In parallel to the implementation of the First and Second Electricity Directives into French Law, EDF was transformed in 2004 into a joint stock company operating under private commercial law in France.[24] However, the French State must hold more than 70% of EDF share capital;[25] currently the France State holds 83.7%.[26] Besides, the French State continues to play an important role in the energy sector via the appointment of representatives[27] (*commissaires du gouvernementl*) to act within certain "key" French energy companies.[28]

Generation

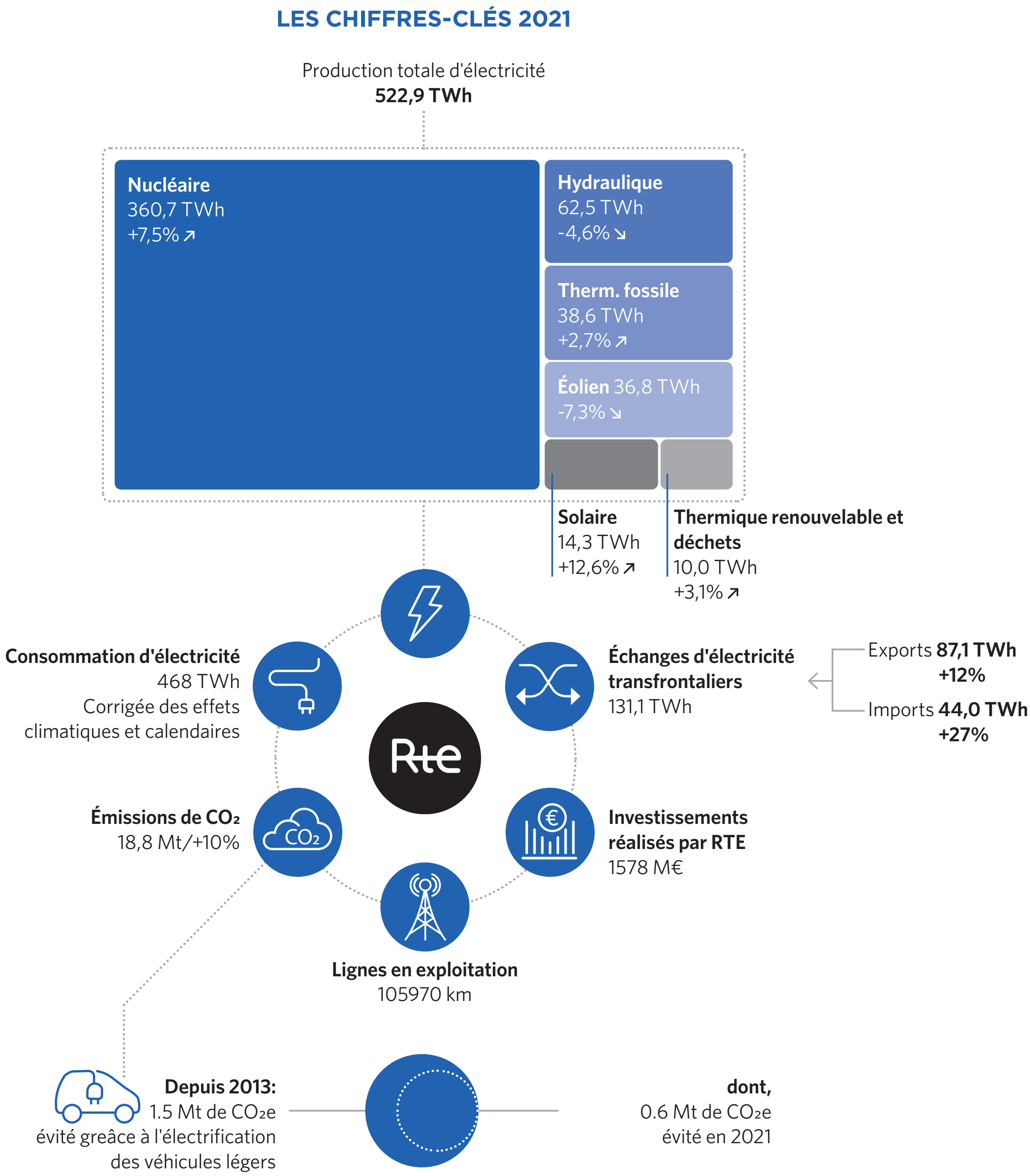
France's electricity mix includes nuclear, hydropower generation, renewable (other than hydropower) and fossil-fired generation.

In 2021, France produced 360,7 TWh of its electricity from nuclear energy and 51,1 TWh from renewable sources (solar and wind).[29] The following chart (extract from the *Réseau de transport d'électricité* (RTE) Report on Electrical balance) summarises the 2021 French electricity production by type of energy.[30]

Law No. 2000-108 opened up the power generation market to competition. As the only nuclear power producer in France, EDF has the largest fleet of generation facilities, producing 81.6% of the country's electricity in 2017 and 8%[31] from renewable sources. ENGIE (formerly GDF SUEZ), notably through *Compagnie du Rhône* (CNR) and SHEM, and Uniper France (formerly E.On) are EDF's main competitors. EDF operates 92.3 GW in mainland France,[32] while ENGIE operates 10 GW.[33]

Generation Authorisation

Any person wishing to become an operator of an electricity generation facility must hold an electricity generation authorisation from the Minister for Energy. This authorisation is nominative and cannot be transferred or assigned to a third party without the prior approval of the same Minister; [34] the approval must be sought by both the transferor and the transferee.



However, certain generation facilities are deemed to be authorised if their maximum capacity is below a threshold based on their source of power.

This threshold has been set in 2018 at 50MW for power plants using renewable sources, 20MW for those using natural gas, 10MW for those using fossil fuel other than gas and coal, 1GW for offshore wind facilities that have been awarded following a public tendering procedure and 300MW for other generation facilities using renewable sources that have been awarded following a public tendering procedure.[35] The electricity sector regulations do not impose any particular formality on a person wishing to operate such facilities.

As a general rule, construction works in France must comply in particular with legal and regulatory provisions relating to building permits, town planning, safety and environment protection.

Hydropower concession regime

Hydraulic power plants have been regulated in France since the early 20th century, in particular under law dated 16 October 1919 *relative à l'utilisation de l'énergie hydraulique*. The hydropower legal regime has, since then, much evolved and is now codified under Articles L. 511-1 *et seq.* and R. 512-1 *et seq.* of the Energy Code.

Under such regime, operators of hydraulic power plants whose output exceeds 4.5 MWh must enter into a concession agreement with the French State (otherwise they shall be granted a simple authorisation).[36] In practice, 80% of the circa 400 existing hydropower concessions are operated by EDF.

Concession agreements are long-term contracts (up to 75 years) that are awarded and renewed following a competitive bidding process organised by the French State[37] and whereby the French State remains the owner of the hydropower installations but delegates the construction and/or operation of such installations to a private company.

Awardees of hydropower concessions are selected based on at least the three following criteria: the financial conditions (ie, the yearly royalty that the awardee is to pay to the French State), the power optimisation (ie, the ability to propose investments to modernise existing facilities or provide new equipment to improve the energy efficiency) and the ability to preserve the water resources and usages.[38]

Note that the French State may decide to award a hydropower concession to a public-private company (called *société d'économie mixte hydroélectrique*), of which shareholding is split between a private company, which will be the operator of the concession, and competent local governments (with a minimum 34% shareholding for the private operator). These modalities will, in particular, enable the French State to keep monitoring the performance of the hydropower concessions that would not be awarded or renewed to the benefit of EDF (*see also the section on Hydropower concession regime in the recent development article for more information*).[39]

At the end of their initial terms, hydropower concessions shall, in principle, be re-tendered by the French State in accordance with the principles above. This principle has been much challenged in France over the past few years (*see the section on Hydropower concession regime in the recent development article for more information*). However, the Energy Code contains several provisions enabling the French State to extend the duration of the concessions and consequently to derogate to this re-tendering principle.

- First, the French State may use the "barycentre method", consisting in bundling together several concessions in the same area and setting a single term for these contracts prior to launching a re-tendering process. As a result, in practice, the concessions that have already expired or that are about to expire will be extended without any competitive process.[40]
- Second, the French State can decide to extend the duration of hydropower concessions without any competitive process when additional investment that were not part of the initial concession have become necessary.[41]

Transmission and distribution

The transmission network is the largest in Europe and is owned and operated by RTE as detailed in a concession agreement entered into with the French State[42] under standard concession specifications.[43] The share capital of RTE can only be held by EDF, the French state, or companies and bodies belonging to the public sector.[44] In December 2016, EDF's board approved the sale of part of its shares in RTE through the creation of a joint venture of EDF (50.1%) and entities belonging to the public sector: *Caisse des Dépôts* and CNP Assurances (49.9 %).[45]

Local authorities' own electricity distribution networks and enter into concession agreements for their development, operation and for the distribution of electricity. Another subsidiary of EDF, ENEDIS (formerly ERDF), delivers 95% of the overall electricity distributed in France. 5% is distributed by DNNs or local distribution companies.[46]

France has decided to apply the independent transmission operator (ITO) model whereby transmission and distribution activities are required to be operated within a framework guaranteeing their independence from generation and supply activities, to ensure non-discriminatory access to all users.[47]

The procedure of TSO certification was implemented into French law in 2011.[48] RTE's certification has been confirmed by a decision of CRE dated 26 January 2012 and renewed by a decision of CRE dated 11 January 2018,[49] issued in accordance with the opinions of the European Commission.[50]

Once the certification is granted, and in the event that the French TSO is being controlled by an entity that is not registered within the European Economic Area, a new certification procedure is required.[51] Therefore, the TSO has an obligation to inform the CRE and the Minister of Energy without delay when being likely to fall under the control of the aforementioned entities.[52]

Moreover, the Minister of Energy may object to the granting of the certification if it considers that the takeover of the TSO is likely to affect the security of national energy supply or that of another member of the European Union. These provisions also apply in case of incorporation in France of a power transmission company by an entity that is not registered within the European Economic Area.[53]

Electricity supply

Electricity supply has been fully open to competition since 1 July 2007, when the right to choose an electricity supplier, a right previously enjoyed only by the largest electricity consumers, was extended to all customers, including residential customers.

EDF's main competitors on the electricity supply side are ENGIE, E.ON (Uniper France, SNET), Enel and Direct Energie.[54] As of 30 September 2018, alternative suppliers held a 18.2% market share in residential sites and a 42.4% in non-residential sites.[55]

Electricity Trading Authorisation

The suppliers of electricity to end-users (*clients finals*) and network operators, when managing shortfalls, must hold a licence to operate (the "*Electricity Trading Authorisation*").[56] To obtain the Electricity Trading Authorisation an application must be made to the Minister for Energy.[57]

Electricity Trading Authorisations are granted based on (i) the technical, economic and financial capacities of the applicant, and (ii) the compatibility of the applicant's project with the obligations imposed on electricity suppliers, and notably with the obligation to secure sufficient guaranteed capacities (see section A.3).[58]

The Electricity Trading Authorisation was previously granted for a period of five years and subject to renewal. This authorisation is now valid for an unlimited period of time, and the existing authorisations do not need to be renewed once their initial period has lapsed.[59] The administration is required to publish a list of the operators holding an Electricity Trading Licence.[60]

Regulated tariffs for end customers

France has historically a large market share subject to regulated tariffs. These regulated tariffs were set by order of the Economy Minister and the Energy Minister until 7 December 2015 and are now set by the CRE subject to the Economy Minister and the Energy Minister not opposing to it.[61] These tariffs are the legacy of the monopoly by EDF and suppliers deriving from local DSOs and, for this reason, they are the only suppliers permitted to sell electricity at regulated tariffs.

Until 1 January 2016, there used to be three different categories of regulated tariffs:[62]

- blue tariffs, which are relevant to consumers subscribing for less than 36kVA (households and small businesses);
- yellow tariffs, which are relevant to consumers subscribing for between 36kVA and 250kVA (medium-size businesses); and
- green tariffs, which are relevant to consumers subscribing for more than 250kVA (consumers from the industrial and sectors).

From 2007 to 2012, the Commission conducted an in-depth investigation with respect to state aid into electricity tariff regulation in France, and the regulated transitional market adjustment tariffs (*Tarif Réglementé Transitoire d'Ajustement du Marché*, or the "TaRTAM" System),[63] excluding blue tariffs customers in both cases.

The Commission issued a decision on 12 June 2012[64] in which it acknowledged that the regulated tariffs were originally introduced to prevent EDF from imposing unreasonable tariffs as a result of its large share of the retail market, but also found that the mechanism has resulted in state aid for French electricity consumers.

The French authorities were required to : (i) immediately end any state aid resulting from the application of the TaRTAM System and end the regulated tariffs for the sale of electricity to large and medium-sized customers (ie yellow and green tariffs) by no later than 31 December 2015; [65] and (ii) open up access to nuclear power by implementing the ARENH (see below). These undertakings were set out in the NOME Law and are now codified.

As a result, yellow and green tariff customers have been required to subscribe to a market contract on or before 1 January 2016. If the customers fail to do so before the deadline, they will automatically be given a 6 month market contract with their supplier (which they may terminate at any time). Thereafter, they will automatically be given a supply contract with a supplier appointed by the CRE following a call for tenders:[66]

- The CRE was empowered to conduct a call for tenders in March 2016. As for the result, the medium price for the lots located on ENEDIS' network was €19.50 per MWh and €10.60 per MWh for the lots located on the local distributors' networks.[67]
- As 52 lots have found no supplier following this first call for tenders, a second call for tenders has been initiated by the CRE in November 2016. However, no successful tenders have been selected following this second call for tenders in respect of the electricity lots (same result regarding the gas lots save one awarded) and the CRE has therefore advised that the prices for these transitory offers should be set at a price level which would substantially strengthen the financial incentive to opt for a new supplier and subscribe a market contract.[68]

Note that households and small businesses may come back to regulated tariffs after having opted for market prices.

Besides, the phase out of the yellow and green tariffs only applies to consumption sites located in metropolitan France. Both households and non-households continue to benefit of the regulated tariffs for the sites located in areas non-connected to the metropolitan France[69] (eg, oversea territories).

Since 1 January 2016, new regulated tariffs have been set:[70]

- blue tariffs, which are applicable to end consumers for (i) sites located in metropolitan France subscribing for less than 36kVA in low tension and (ii) sites located in non-interconnected areas (ie. overseas territories) connected in low tension;
- yellow tariffs, which are applicable to end consumers for sites located in non-interconnected areas (ie. overseas territories) subscribing for more than 36kVA in low tension; and
- green tariffs, which are applicable to end consumers for (i) sites located in metropolitan France subscribing for less than 36kVA in high tension and (ii) sites located in non-interconnected areas (ie. overseas territories) connected in high tension.

Numerous claims and several legal issues have arisen in relation to the regulated tariffs over the years (see article on recent developments for more information).[71]

In this respect, the *Conseil d'Etat* recently stated that a decision of the competent minister setting out the regulated tariffs was unlawful.[72] Pursuant to this decision, although the existence of electricity regulated tariffs is not considered as unlawful in its principle, the *Conseil d'Etat* however, considered that the benefit of the same tariff for all end consumers located in metropolitan France subscribing, in low tension, for less than 36 kVa, was not proportionate to the contemplated economic general purpose and that consequently, large businesses should no longer benefit from these tariffs (as opposed to households and small businesses).

Taking into account the aforementioned decision, the CRE proposed to define revised tariffs applicable to large businesses located in metropolitan France.[73] This proposal was subsequently followed by the competent ministers in July 2018.[74] The level of regulated tariffs applicable to end consumers located in areas non-connected to the metropolitan France remained however unchanged.

As a result, large businesses benefiting from regulated tariffs from the date of the above mentioned CRE decision (ie 12 July 2018) were entitled to keep benefiting from these tariffs until they decide to change their power or tariff options. Other large businesses (defined as companies (i) employing more than 5,000 persons or (ii) having an annual turnover exceeding 1,500 million euros or an annual balance sheet exceeding 2,000 million euros)[75] shall no longer be eligible to such regulated tariffs.

According to the NOME Law, the regulated tariffs had to be set so as to cover the costs of the ARENH, the cost of the guaranteed interruptibility and generation capacities imposed on the suppliers, the network costs and sales costs as well as a reasonable remuneration. This new method (called *tarification par empillement*) was scheduled to be implemented progressively up to 31 December 2015 in order to reduce the gap between regulated tariffs and market prices by integrating the cost of the ARENH into the determination of the regulated tariffs. Decree No. 2014-1250 of 28 October 2014 ended this transitional period,[76] and the Energy Transition Law reflected this in Article L. 337-6 of the Energy Code.

Accès Régulé à l'Electricité Nucléaire Historique (ARENH)

With a view to increasing competition in the power supply market and ensuring low prices for consumers, the NOME Law temporarily (until 31 December 2025) allows entities supplying electricity to consumers and network operators in mainland France to access a share of EDF's nuclear electricity output at a regulated tariff. This is known as the ARENH.[77]

Total volume capacity sold

The global volume of electricity to be sold by EDF to its competitors is based on the suppliers' forecasts[78] and market competition conditions and is set by the ministers of energy and the economy[79] upon proposal by the CRE, within a maximum cap of 100TWh annually[80]. The actual volume has been set to 100TWh by the ministerial order dated 28 April 2011[81]. This represents approximately a quarter of the nuclear electricity produced by EDF.

Economic conditions

The NOME Law provides that the economic conditions for purchasing access to nuclear electricity must be equivalent to those applicable to EDF when it produces the electricity in its nuclear power plants. Until the end of 2025, the tariff for electricity sold under the ARENH system will be set annually by the Minister of Economy and the Minister of Energy, further to a proposal from the CRE. The ARENH tariff is set at €42/MWh since 1 January 2012.[82]

As of 8 December 2013, the tariffs are set by the ministers of energy and economy, acting upon a proposal of the CRE. In the absence of opposition from the ministers within three months after CRE's proposal, the tariff proposed by the CRE is deemed accepted.[83] As a matter of principle, this tariff will take into account the return on equity, the exploitation costs, the investment costs relating to the maintenance or to extension of the operating life of nuclear plants and the long-term nuclear expenses, including provisional costs of nuclear decommissioning. However, the tariff of the electricity sold under the ARENH mechanism does not take into account the cost of the renewal of nuclear plants. The government was expected to issue a decree clarifying the methodology for identifying and accounting for the costs (referred to above) on which are based the ARENH tariffs.[84] Until this decree is issued, the ARENH tariff shall remain at €42/MWh.

Due to overcapacity and a low level of the prices on the wholesale market, applications for ARENH have been limited to 71.5TWh in 2014, 16.1TWh in 2015 and no subscription at all was made in 2016. In 2017 and 2018, the volumes requested amounted respectively to 81.3TWh and 87.1TWh.[85] For 2019, the volume of ARENH requested has exceeded the 100TWh threshold (132.98 TWh according to the CRE).[86] Consequently, an in-depth reform of the ARENH mechanism (notably a potential increase of the actual threshold) is being contemplated as stated by Emmanuel Macron in his speech introducing the new multi-annual energy program (PPE) on 27 November 2018 (see the recent development article).

Modalities to benefit from ARENH mechanism for suppliers

The CRE establishes the maximum volume of electricity each supplier may buy under the ARENH mechanism annually.[87] The CRE notifies each supplier of the volume it may buy several times a year. Such information exchanges are set out by the transmission system operator under CRE's supervision, so that EDF may not have access to specific information related to each supplier.[88]

The conditions for applying for the ARENH mechanism are provided for by a decree dated 28 April 2011 and the Energy Code.[89] Two delivery periods are set in respect of a given year, starting from 1 January and 1 July.[90]

Any supplier who would like to benefit from the ARENH tariff is required to enter into a framework agreement with EDF,[91] according to a model form agreement set out by a ministerial order[92] amended in November 2016 and in March 2019 regarding its appendices.[93] Pursuant to Article L.336-5 of the Energy Code, the list of the suppliers who have entered into a framework agreement with EDF is published on CRE's website.[94]

Regulation

Regulations are implemented by the national regulatory authority (CRE) and by the Minister of Energy. The CRE is an independent administrative authority. It was established in 2000 to regulate the electricity sector. Its activities were extended in 2003 to the regulation of gas activities.

The CRE has an advisory role with the power to make proposals and give opinions, as well as approval and regulatory decision-making powers.[95]

The CRE is empowered primarily to regulate access to electricity and gas networks and gas facilities. For example, the CRE proposes usage tariffs for public transmission and distribution networks to the ministers for the economy and industry. It also receives the various contracts and protocols related to network and facilities access, as well as a notification of refusals of the TSO to enter into contracts or protocols with suppliers for the access to the grid[96] or model contracts and protocols entered into between the TSO and a producer relating to access to the grid.[97]

The CRE guarantees the independence of the network operators. In this respect, for example, it prepares a report which reviews compliance by operators with the codes of conduct and makes an assessment of the independence of the network operators, approves the annual investment programme of the transmission system operator, approves the rules of accounting separation applicable to vertically integrated undertakings,[98] and has a role in monitoring through its powers of inquiry.

The CRE is entrusted with the task of market regulation: it supervises the transactions carried out between suppliers, traders and producers, transactions carried out on organised markets, as well as cross-border exchange transactions. The CRE's prerogatives were extended by the NOME Law to the implementation of the ARENH mechanism.

The CRE also has the jurisdiction to settle disputes and to apply penalties, which the law of 7 December 2006 granted to an *ad hoc* committee within the CRE: the dispute settlement and penalty committee (CoRDIS).[99]

The Minister for energy benefits from certain prerogatives in terms of the determination of tariffs, control and penalties.

A.2 Third party access regime

Energy production sites with a capacity of less than 12MW (or up to 17MW if a derogation is granted) are directly connected to the grid through the entities in charge of power distribution to the end-users (ENEDIS or local distributors) in LV or HVA voltage. When energy production sites have a capacity of more than 12MW (subject to the above-mentioned derogation), they are connected to the grid by RTE as sole TSO.[100]

Network operators must guarantee access to the public transmission and distribution networks.[101] Access to the networks is ensured through standard form agreements that are entered into between the transmission and distribution network operators and the users of these networks. Any refusal to enter into an agreement for access to the public networks must be justified and notified to the applicant and the CRE. The network operator is required to deny access to a generator which is not duly authorised.[102]

The Energy Transition Law introduced an 18-month period for the TSO to complete the grid connection of a renewable generation facility with an installed capacity over 3KVA.[103]

A.3 Market design

Development of the capacity mechanism

France used to be an energy-only market. Following a report on the issues generated by the increase in peak power consumption,[104] the NOME Law implemented a "capacity" mechanism, whereby electricity suppliers must prove their ability to meet their customers' needs at any time and in particular at peak times through the acquisition of "guaranteed capacities".[105] In 2013, the capacity mechanism obligation has been extended to large electricity consumers who acquire electricity directly on the wholesale market.[106] Such consumers can however transfer the capacity obligation to its electricity supplier.[107] Since 2015, the supplier can also transfer its capacity obligations to its consumer.[108]

The capacity mechanism incentivises peak load management plans. Suppliers are assigned capacity obligations based on their customers' actual consumption during peak periods. The supplier may obtain these guaranteed capacities from:

- electricity producers, operating power plants in France, who are required to obtain a certification of their installations' generation capacity; and
- consumers who can request certification of their ability to curtail their consumption at peak period (ie, the demand response capacities).

RTE oversees calculating and controlling the electricity suppliers' obligations regarding guaranteed capacities,[109] as well as certifying and controlling the capacities of the electricity producers/consumers.[110] Fines are used in order to encourage suppliers to comply with the guaranteed capacities requirements.[111]

These guaranteed capacities can be sold and exchanged; consequently, a market for these capacities will emerge. However, in 2012 the French competition authority has raised serious doubts on the impact of the capacity mechanism on the structure of the electricity supply market.[112]

The broad parameters of this capacity mechanism are provided in the implementing decree adopted on 14 December 2012,[113] partly codified since 2016 in the Energy Code.[114] The decree provides for a large set of rules to be adopted by the Minister and by the CRE to determine the calculation methods, the terms and conditions of capacity certifications, and the overall methods of control and sanctions. RTE submitted a first set of rules on 6 May 2014. Following the positive opinion of the CRE on 28 May 2014,[115] these rules were adopted by a ministerial order on 22 January 2015.[116]

Throughout 2015 and 2016, new capacity mechanisms were under scrutiny for their compliance with state aid rules. On 9 September 2015 the *Conseil d'Etat* rejected a state aid claim against the implementing decree of 14 December 2012, affirming that no State resources are involved.[117] However, it decided to stay the proceedings and to submit a question for European Court of Justice's preliminary ruling regarding the compatibility of the capacity mechanism with principles of the free movement of goods.[118] However, following the withdrawal of the claim by the claimant (ANODE), the *Conseil d'Etat* decided on 16 March 2016 to withdraw its request for a preliminary ruling[119] and the case has been removed from the Court Register.[120] Later, in its decision on 13 May 2016, the *Conseil d'Etat* invalidated some provisions of the implementing decree (ie, provisions on the certification of the capacities) on procedural grounds.[121]

At the same time, the Commission launched a state aid sector inquiry into national capacity mechanisms involving France along with other countries.[122] As a result of exchanges with Commission, the French Government agreed to amend the existing rules to ensure its compliance with EU state aid framework, and notably, to prevent market manipulations and to open the capacity market to providers located in neighbouring Member States. On 14 November 2016, RTE submitted to the CRE a new set of rules, taking into account the modifications undertaken by the French Government. The CRE approved the modifications on 24 November 2016[123] and the rules have been officially adopted on 29 November 2016.[124] French capacity mechanism system has been validated by the Commission for 10 years.[125]

French capacity mechanism has been amended by a decree dated 15 November 2018[126] to consider the remaining European Commission's requirements that have presided over the above-mentioned validation of the capacity mechanism. In particular, the Energy Code has been revised to (i) include capacities provided from other Member States and to (ii) create a new tender mechanism whereby selected capacities providers shall benefit from a 7-year contract providing for a guaranteed price in exchange for the maintenance of their capacities. On that basis, a new set of rules has been adopted on 21 December 2018.[127]

RTE submitted a new set of rules to the CRE on 29 October 2019, which was the third major revision of the rules that came into force on 22 January 2015. The CRE partially approved this set of rules on 28 November 2019.[128] On 28 August 2020, RTE submitted another set of rules to the CRE, which was approved by the CRE on 10 September 2020.[129] RTE's proposals introduced exceptional measures into the rules of the capacity mechanism to facilitate the emergence of capacities contributing to the security of supply over the winter of 2020-2021; such measures have received a positive opinion from CRE.[130]

On 29 November 2021, RTE submitted another set of rules to the CRE. The CRE partially approved this set of rules on 16 December 2021. The same day, RTE's proposal introducing an agreement between RTE and the distribution system operators, concerning data exchanges for the calculation of the capacity obligation have received a positive opinion from the CRE.

At the end of the seventh auction (13 December 2018) the French capacity mechanism for delivery year 2019 and the related guaranteed capacities were exchanged at a price of €18,046 per MW.[131] Additionally, at the end of the first auction (21 March 2019) the French capacity mechanism for delivery year 2020 and the relative guaranteed capacities were exchanged at a price of €20.001 per MW.[132] At the end of the fifth auction (11 March 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of €28,30 per MW.[133] At the end of the sixth 2021 auction (22 April 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of €28,15 per MW.[134] At the end of the seventh auction (24 June 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of €28.81 per MW.[135] At the end of the eighth auction (23 September 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of €29.90 per MW[136].

At the end of the ninth auction (28 October 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of EUR 31.50 per MW[137]. At the end of the tenth auction (9 December 2021) for delivery year 2022, the guaranteed capacities were exchanged at a price of €23.90 per MW[138].

Development of demand response mechanism

Demand response mechanisms, allowing to curtail the electricity consumption at peak periods, has also been actively developing in France since its creation by the Energy Transition Law. The design of the new demand response market gave rise to vivid opposition between demand response operators and electricity suppliers. This is because demand response reduces the consumption of electricity supplied by suppliers who could market the shedding capacities (*volumes d'effacement*) related to the capacities they have supplied on the wholesale energy market. Therefore, the demand response operators must reimburse the electricity supplier for their loss. In 2009 the CRE supported the idea of the reimbursement,[139] but its decision has further been cancelled by the *Conseil d'Etat*[140]. In April 2013. The first legal basis for demand response activity has been set up,[141] providing for:

- the principle of reimbursement of electricity suppliers by the demand response operators, considering "*the amount of electricity injected*" on the transmission network; and
- public subsidisation of demand response activity and specifying that the results of such activity must be commercialised on the wholesale energy market.

A first set of rules was approved by the CRE on 28 November 2013 and became effective on 18 December 2013 for a one-year period.[142] Further, on 10 March 2014, RTE proposed a set of rules allowing demand response operators to sell the shedding capacities on the wholesale market. Those rules were approved by the CRE on 7 May 2014,[143] but were challenged by the demand response operators before the *Conseil d'Etat*, who rejected such claims.[144] As a result of this experimentation phase, the rules on the marketing of the shedding capacities on the wholesale energy market have been approved by the CRE on 17 December 2014.[145] The claims against this approval were also rejected by the *Conseil d'Etat*.[146]

Demand response activity is subject to a prior technical approval, such approval being limited in time and subject to specific technical requirements set out in the implementing regulatory decisions.[147] The shedding capacities are further certified by a TSO to guarantee the effectiveness of the reduction in consumption resulting from such demand response activity.[148]

When the shaving capacities do not meet the objectives of the multiannual energy programming or when their development is insufficient in view of the needs highlighted in the multiannual forecast balance sheet, the administrative authority may resort to the call for tenders' procedure.[149] Each call for tenders comprises two lots:

- lot 1, reserved for sites with a subscribed power less than or equal to 1 MVA (low voltage) and 1 MW (HTA); and
- lot 2, for sites with a subscribed power greater than 1 MVA (low voltage) and 1 MW (high voltage).[150]

Following the approval of the specifications by the Minister in charge of energy, RTE launched a call for tenders for 2022. The maximum volume that can be contracted for 2022 is set at the level of the ceiling authorised by the European Commission, taking into account the possibility of carrying over volumes authorised in previous years and not contracted. This volume amounts to 7,940 MW, including 3,750 MW reserved for sites with a subscribed power less than or equal to 1 MW.[151] As a TSO, RTE must maintain a constant balance between power supply and demand, and also make sure that the reserves required for the system to function are available and activated.[152] In this respect, when the consumption reduction capacities do not match the objectives set out at the national level, RTE may launch a call for tenders to ensure that an adequate number of balancing bids (for additional production capacities, but also for demand-side capacities) will be submitted to the balancing mechanism daily and that activation timeframes are compatible with system security requirements.[153]

Finally, an intention to subsidise the demand response activity also gave rise to regulatory changes following doubts on its compatibility with state aid rules. In 2013, the French competition authority warned about potential qualification of state aid.[154] The subsidisation was nonetheless put in place, and its modalities were established by a decree dated 3 July 2014.[155] The first amount of the subsidy was established in a ministerial order dated 11 January 2015; it was fixed at €16 for the reduction of electricity in peak hours and €2 in normal hours.[156] However, on 16 March 2016, the *Conseil d'Etat* invalidated the ministerial order, claiming it was illegal state aid.[157] Before this, the very principles of the subsidy had already been cancelled by the Energy Transition Law.

A.4 Tariff regulation

Regulated tariffs[158] for the use of the transmission and distribution networks and for supply are set by a joint order of the minister for the economy and the minister for energy, either upon proposal, by or after, consultation with the CRE. Tariffs for the use of the networks are supposed to entirely cover the operators' costs and take into account the return on capital invested by the operators. A discount on this tariff for the use of the networks may be applied to electricity intensive industries that have stable and predictable, or counter-cyclical consumption profiles.[159] The current tariffs (TURPE 5) came into force on 1 August 2017 for 4 years.[160]

A possibility of adjustment each year on the 1st of August was provided. In consequence, the tariff evolved by – 0,21% on the 1 August 2018, following a decision issued by the CRE.[161]

A.5 Market entry

Subject to the licensing restrictions described above, liberalisation has lifted the barriers to entry to the electricity market.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The law provides for PSOs to be endorsed by: (i) all electricity generators; (ii) EDF and transmission and distribution operators; and (iii) the DNNs (for the purpose of guaranteeing supply throughout France).

Specific PSOs are assigned to EDF and are detailed in an agreement entered into with the state called the "public service contract". The public service contract was entered into on 24 October 2005 and will remain in force for as long as it is not replaced by a new contract.[162]

The charges relating to the public service obligations, which are imposed on the electricity operators are compensated through a payment to the electricity public service (*contribution au service public de l'électricité* or "CSPE"). The CSPE was introduced in 2003, was financed by specific taxations (eg, public service electricity taxation, specific solidarity tariff taxation, bio-natural gas taxation) and was managed outside the annual budget by the public operator *Caisse des dépôts et consignations*.[163]

Following numerous cases challenging the CSPE systems for breaching state-aid rules and for clarification purposes, the PSO funding framework has been substantially reformed (starting 1 January 2016 with transitional measures) and is now financed by the national budget but continues to be managed by the *Caisse des dépôts et consignation*. The reform introduces two specific purposes accounts in the State budget:

- A separate account called 'Energy Transition' within the French budget has been created to compensate for the cost of policies in support of renewables, including bio-natural gas (feed-in tariffs, additional remuneration) and demand response expenditures. This account also includes the reimbursement of the unpaid compensations due until 31 December 2015 to companies fulfilling PSOs. It is financed by new forms of the energy consumption taxes (the *Taxe intérieure sur la consommation finale d'électricité* that absorbs the former CSPE), gas consumption tax (*Taxe intérieure sur la consommation de gaz naturel*) and certain other taxes.
- An 'Energy Public Service' programme covering compensation for other public service costs, such as the additional costs incurred for electricity produced in ZNI due to tariff equalization (excluding the cost of renewable support) and revenue losses and additional.

The decree no. 2016-158 of 18 February 2016[164] integrates the legislative evolutions related to public service compensations in the field of energy in the regulatory part of the Energy Code.

Universal service provisions

From 2005 and to the 1st January 2018, special energy tariffs called basic necessity tariffs (*tarifs de première nécessité*) existed in France in order to deal with the increasing of fuel poverty. Such tariffs were designed to cover domestic clients whose annual revenues were lower than a threshold set out in a decree. This system was abolished in 2015 by the Law on Energy transition for green growth and replaced as from the 1st January 2018 by the energy check.[165]

The energy check is a specific method of payment created for people whose income are below a certain threshold in order to pay their energy expenses for their homes. It is a method of payment that electricity suppliers are required to accept.[166] The amount covered by the check is set by the regulatory power and will depend on the annual income of the household.[167]

Smart metering

In accordance with the Third Energy Package, operators of public transmission and distribution networks are required to set up mechanisms enabling suppliers to propose different prices to their clients, depending on the period of the year or day, and encouraging network users to limit their consumption in periods during which overall consumption is at its highest.[168] Following the CRE proposal, a decree has been adopted which provides for an obligation to set up a new metering system enabling users to access daily data relating to their generation and/or consumption of electricity.[169] Project "Linky" developed by ENEDIS aims to comply with this obligation. On 30 July 2013, following trials by ENEDIS and a technical-economical study conducted by CRE,[170] ENEDIS published a proposal in the Official Journal of the European Union to supply meters (2.5 million single-phase meters and half a million three-meter phase).[171] This proposal is the first stage of the replacement of existing meters by Linky smart meters. The CRE, estimated the cost of the implementation of this metering system to approximately €5 billion.[172] Financing expenses are covered by the TURPE tariffs, combined with a scheme that gives ENEDIS a financial incentive to optimise the quantity/cost-of-debt ratio by allowing the network operator to keep any gains from optimisation. In return, ENEDIS bears the impact of any poor performance, for instance if the actual cost of debt is higher than the target cost used by the CRE.[173]

A ministerial order of 4 January 2012 specifies the functionalities of the smart-metering system at different voltage levels, as well as the conditions of interoperability. Currently Linky is being implemented by ENEDIS. The decree no. 2015-1823 dated 30 December 2015[174] integrates in the regulatory part of the energy code provisions related to the smart-metering system.

On 20 March 2013, the *Conseil d'Etat* has rejected several claims filed against this ministerial order dated 4 January 2012 and held in particular that electromagnetic radiation from Linky does not exceed the thresholds set out in the French and European legislation or agreed upon by the World Health Organisation.[175] Even if several local authorities and associations were opposed to the deployment of Linky based notably on health considerations in relation to electromagnetic radiation,[176] the *Conseil d'Etat* ruled that municipalities were not competent to prohibit the installation of smart meters.[177] The same position was later followed by the administrative courts of appeal of Paris and Versailles.[178]

Currently, approximatively 35 million of Linky smart meters have been installed in 6 years.[179]

Electric mobility

Developing electric mobility and equipping the French territory with a complete and homogenous network of charging stations for electric vehicles has become a key strategic axis of the French ecological transition.

In that respect, France has set out the following key targets:

- the Energy Transition Law provides that at least 7 million charging stations for hybrid and electric vehicles should be built by 2030;[180]
- the PPE sets a higher target of 4.8 million vehicles by 2028;[181]
- the Climate Plan (*Plan Climat*)[182] and the PPE contemplate the end of sale of diesel vehicles by 2040; and
- the PPE targets a reduction in the production of greenhouse emissions emitted by vehicles by 35% (compared to 2021).

In order to reach these targets, certain entities (eg State, local authorities, car rental companies or taxi companies) shall now acquire a minimum percentage of low emission vehicles when they come to renewing their respective fleet.[183] This requirement should be extended to any private corporations owning more than 100 vehicles by the draft bill relating to mobility (see below).

In parallel, the deployment of charging infrastructures has been fostered through:

- the granting of aids by the ADEME (*Agence de l'Environnement et de la Maîtrise de l'Energie*) to support projects developed by local governments: as at 30 June 2018, the ADEME supports 76 projects for a total amount of aid of circa €56 million;[184]
- the granting, from 1 September 2014 to 31 December 2019, of tax credits to individuals installing charging stations at home;[185]
- the adoption of a decree dedicated to enable the harmonised development of charging stations in terms of power, interoperability and access to the stations;[186]
- the adoption of a decree precising the elaboration of master plans for the development of charging infrastructures open to the public for electric vehicles and plug-in hybrid vehicles;[187]
- the creation by the Climate and Resilience Law of an obligation to install electric vehicle charging points in car parks of more than 20 parking spaces;[188]
- the creation of new provisions in the Energy Code clarifying the deployment of electric vehicle charging infrastructure.[189]

The aim of the French government is to keep on accelerating the installation of charging stations (As of July 17, 2021, there were 43,700 charging stations installed in France. That's an additional 11,000 installed in 6 months and a 33% increase in the number of kiosks over the first six months of 2021).[190] To this end, the Law on the orientation of mobilities[191] provides for the following main incentive measures:

- reduction in the costs for the connection of the charging stations to the electricity grid by increasing from 40% to 75% the part of these costs paid through the TURPE tariffs from 1 January 2022;[192]
- obligations for developers to pre-equip car parks located in new or refurbished buildings with charging stations from March 2021 onwards;[193] and
- obligations for car parks located in non-residential or mixed buildings to include at least one charging station from 1 January 2025 onwards.[194]

In addition, Decree no. 2021-153 of 12 February 2021 introduced aid for investments in fast charging facilities for electric vehicles on major roads.[195]

The Decree no. 2022-945 of 28 June 2022 specifies, in the case where a charging station operator undertakes to install in a collective building, at no cost to the owner of the building or, in the case of a condominium, to the condominium infrastructure that make it possible to subsequently install charging stations for electric vehicles, the elements contained in the agreement.[196]

In addition, the Decree no. 2022-959 of 29 June 2022[197] aims at multiplying the points of recharging for electric vehicles and detailing the content of the agreement to be executed between the operator and the owner of the building.

A.7 Cross-border interconnectors

Operators of interconnectors

Under French law, RTE is in charge of operating the transmission grid which includes operating interconnections with other countries' grids.[198]

There is no specific legislation granting a third party the right to operate an interconnector.

However, in light of this lack of specific legislation, CRE has developed an argumentation in its deliberation of 29 March 2012[199] which concludes that the only possibility for a private party to operate an interconnector is through the mechanism of the exemption provided in Article 17 of EC regulation 2009/714 (repealed and replaced by Article 63 of Regulation 2019/943 which provides for the same dispositions). This decision specifies the process for granting exemptions and specifically, certain information to be included in the exemption application, and how the CRE will determine whether to grant the exemption.

The legal framework for the processing of connection requests and the rules for interconnector access to the grid were implemented by CRE and RTE as follows:

- a CRE decision of 26 July 2011 establishes the principles to be followed by the TSO when defining the applicable rules;
- a CRE decision of 9 May 2012 approves the first version of the technical documentation prepared by RTE in this regard. RTE recently published a fourth version of the technical documentation which has been enforceable since 1 July 2021;
- two CRE decisions of 17 June 2021, approve the procedure and the connection agreement for the NDIs;[200]
- a CRE decision of 17 March 2022 approves the final model contract for access to the public electricity transmission network for the new derogatory interconnections.[201]

The exemptions granted by the CRE, to ElecLink in a decision of 28 August 2014 for an interconnection between France and the UK, and to Piemonte Savoia in a decision of 12 May 2016 for an interconnection between France and Italy, are the only exemptions granted to date.

In a letter of formal notice of February 2015, the Commission found that French legislation prevents undertakings other than the national incumbent system operator for electricity from building and operating interconnectors to other EU Member States. In the absence of action by France, the Commission sent France a reasoned opinion in July 2016. According to European Commission's website, the case has been closed on 8 November 2018.[202]

Operation of the existing interconnectors by RTE

France has interconnectors with six countries: Italy, England, Germany, Spain, Belgium and Switzerland. Commercial capacities are awarded by RTE pursuant to conditions applicable to each interconnection.

To set up an import or export programme exchange, a market player must first acquire capacity rights and then submit the exchange programme that it wishes to implement within the capacity acquired to RTE. The provisions relating to the certification of capacities and derogatory interconnections are specified in Article R. 335-24 and following of the Energy Code.[203] The mechanisms to nominate the exchange programmes on all French interconnectors are described in the 'Access Rules for Imports and Exports on the French Public Power Transmission System'[204] which sets out the terms and conditions of exchange programme nominations. The mechanisms for cross-border capacity allocation are subject to specific rules coordinated with other TSOs, either on a bilateral or regional basis.

The available commercial capacity is allocated for different timeframes: part of this capacity is allocated as periodic Physical Transmission Rights ("PTRs") (yearly and monthly PTRs) and the rest is allocated as daily PTRs. On the French borders, the periodic PTRs are allocated through "explicit auctions", the daily PTRs through "explicit" or "implicit auctions", depending on the border, and the intra-day PTRs through explicit auctions or "improved pro rata mechanisms", depending on the border.

During the year 2020, France exported 77,8TWh and imported 34,6TWh, for an exchange balance of 43,2TWh.[205]

B. Oil and gas

B.1 Industry structure

Background

The production, transportation, distribution, and supply of natural gas was nationalised by law No. 46-628 dated 8 April 1946, which granted Gaz de France a quasi-monopoly over these activities. This monopoly has evolved over time, mainly because of European directives. Gaz de France was transformed into a joint stock company in 2004[206] and privatised in 2008.[207]

ENGIE (having replaced GDF Suez since 2015) is the main player in the French gas market. Its ties with the public sector remain strong as specific thresholds for state ownership of their shares continue to apply. Article L. 111-68 of the Energy Code provides that the State shall hold at least a 33% shareholding in ENGIE.

Since 2022, ENGIE is owned at 23,64% by the French State which also holds 33,78% of the voting rights of the company.[208]

In addition to this corporate control, and in accordance with Article L. 111-69 of the Energy Code, the share capital of ENGIE includes a 'golden share' which is held by the French State. The purpose of the 'golden share' is to protect France's critical interests in the energy sector and, more specifically, to ensure the continuity and safeguarding of energy supply. The French State also appoints representatives (*commissaires du gouvernement*) to act within certain energy companies, including ENGIE (see section A.1).[209]

Regarding the transposition of the First, Second and Third Gas Directives into French law, see our developments in section A.1.

Transportation

Total stopped selling gas from the most important gas field in France (Lacq) in 2013 (a residual production is maintained for the benefit of some local industries).[210] Since then, more than 99% of the gas consumed in France is imported.[211]

There are two natural gas network operators in France:

- GRTgaz, a subsidiary of GDF SUEZ, which operates the B-gas (natural gas with a low calorific value) network in the north of France and a major part of the H-gas (natural gas with a high calorific value) network.
- Terega (formerly called TIGF) now owned by a consortium composed of Snam (40.5%), GIC (31.5%), EDF (18%) and Crédit Agricole Assurances (PREDICA) (10%)[212] which operates the H-gas network in the south-west of France. Please see below for the certification requirements involved by these changes of shareholders. The network operators now own the pipelines, following the State's termination of the concession agreements and the sale of such pipelines to the operators.[213]

France decided to apply the ITO model, whereby transmission and distribution activities are required to be operated within a framework guaranteeing their independence from generation and supply activities, in order to ensure non-discriminatory access for all users.[214]

Please refer to section A.1 for more details on the procedure for certification of the electricity TSOs, which also applies to TSOs in the gas sector. GRTgaz and Terega have been certified by the CRE on 26 January 2012.[215]

Following the sale of Total SA's shares to third-party companies in 2013, a new TSO certification from the CRE was required for Terega as:

- in accordance with Article L. 111-4 of the Energy Code, the transaction could alter the organisation of Terega or of its shareholders in a manner that may affect their compliance with the independence requirements which apply to Terega as a TSO; and
- in accordance with Article L. 111-5 of the Energy Code, one of the new shareholders of Terega was not a company registered within the European Economic Area (GIC is a Singaporean entity).

The Commission took a position in favour of the CRE draft decision dated 4 June 2014, further to which the CRE granted Terega a new TSO certification on 3 July 2014.[216] The change meant that Terega was no longer eligible for the ITO model, and therefore had to shift to the FOU model. The certification of Terega has been reviewed a second time and uphold in February 2016 with the entry of PREDICA in its share capital.[217] The certification of Terega has also been confirmed in September 2018 following GIC's acquisition of a shareholding in an energy production company.[218]

Construction and operation of natural gas transportation pipelines must be authorised by a competent administrative body, following a procedure set out by the Environment Code.[219] The *ordonnance* No. 2016-282 dated 10 March 2016 facilitates the procedure for getting authorisations to occupy public domain for projects concerning gas pipelines declared of public interest. This authorisation is automatically granted to the declaration of public interest holder.

Distribution

GRDF, a subsidiary of ENGIE, has an historic gas distribution monopoly through long-term concessions entered into with municipalities.[220] As of 31 December 2015, the average residual term of GRDF's concession contracts (weighted by volumes distributed) was 12.91 years.[221]

Natural gas distribution is considered to be a communal public service under French law in relation to new networks. Each local authority grants a concession to a distributor to operate this public service on its territory. The concessions are entered into or renewed based on standard specifications. Distribution structures within the scope of the concession belong to the local authorities as soon as they are constructed, even though they are built and financed by the distributor.[222]

Supply

ENGIE reaffirmed its historic leading position in gas market.[223] As of 31 December 2018, alternative suppliers had only a 19.5% share of the residential market, representing 30.33TWh. However, industrial, local authorities and business markets are much more open to competition as alternative suppliers hold a share of 43%, representing 121.84TWh.[224] On the same date, some twenty foreign companies were active authorised suppliers.[225]

Regulated tariffs for end customers

Supply contracts may provide either for regulated tariffs or market prices. ENGIE is the main supplier authorised to enter into contracts with regulated tariffs. Regulated tariffs are set in accordance with articles L. 445-1 and R. 445-1 *et seq*. of the Energy Code.[226] Over the years, numerous claims have been filed against the regulated tariffs, and several legal issues have arisen in relation to them.[227]

Since 1 January 2016, regulated tariffs have been removed for non-residential consumers, except small consumers (following an investigation of the Commission, see section A.1). As of 31 December 2018, regulated tariffs have been chosen for 75% of the sites.[228]

The CRE was empowered to conduct a call for tenders to select gas suppliers for customers that have not opted for one within the 6-month transitory period.

Following the tender of March 2016, combined both electricity and gas lots (see section A.1), the medium price was (i) €8.06 per MWh for the lots located on GRDF's network and (ii) €8.10 per MWh for the lots located on local distributors' networks.[229]

As 6 lots did not find a gas supplier following this first call for tenders, a second call for tenders was initiated by the CRE in November 2016. Only one tender was selected and consequently awarded a lot (see section A.1 regarding the CRE's recommendation).[230]

B.2 Third party access regime to gas transportation networks

Non-discriminatory access to the gas transportation network must be guaranteed by the network operator.[231] Network operation activities must be conducted in accordance with a code of conduct.[232] The CRE publishes annual reports on compliance with the code of conduct and the independence of the transportation network operator.[233]

The GRTgaz network is divided into two balancing zones, called North and South. The Teréga network constitutes a balancing zone.[234] Each of the balancing zones constitutes an "entry-exit" system.

Following Article L. 452-2 of the Energy Code the CRE set out the rules about the tariffs for the use of the transportation network (called "ATRT"),[235] the GRDF distribution network (called "ATRD")[236] and the LNG facilities (called "ATTM").[237] For transportation networks, the tariffs are calculated according to an entry-exit scheme.[238] For distribution networks, the same pricing structure applies to all regions operated by a distributor. For LNG terminals, a specific tariff applies to each terminal.

B.3 LNG and gas storage

LNG

There are currently four (4) LNG import port terminals in operation in France: Fos-Tonkin,[239] Montoir-de-Bretagne,[240] Fos Cavaou[241] and Dunkirk (the commercial operation of the latter one has recently started on 1 January 2017).[242]

Fos-Tonkin and Montoir-de-Bretagne are owned and operated by Elengy, a subsidiary of GRTgaz,[243] and Fos Cavaou is operated by Fosmax LNG, a subsidiary of Elengy (100%).[244] The Dunkirk terminal is owned and operated by Dunkerque LNG a company held at 61% by a consortium comprising Fluxys, Axa IM and Credit Agricole Assurances and at 39% by a consortium comprising Korean investors namely IPM Group and Samsung Asset Management.[245] The terminal is operated by Gaz-Opale, jointly owned by Dunkerque LNG (51%) and Fluxys (49%).[246]

Access to these terminals is open to third parties and their activities and tariffs are regulated.

The regulated activities of these LNG terminals cover the following areas: (i) standard unloading and recharging activities; and (ii) services and experiments related to the standard activities referred to above, such as pooling or dedicated storage.

Third-party access to LNG facilities is guaranteed by French law[247] under the terms and conditions set out in a contract entered into by the LNG terminal operator. However, access to these facilities may be limited if they do not have enough available capacity. As the development of a competitive gas market could be impeded in the absence of access to detailed information on capacity, CRE has asked the LNG terminals operators to publish capacity data (including regasification capacity, maximum firm marketable capacity, firm capacity subscribed to and firm capacity available), together with the method of maximum firm capacity calculation.[248]

Besides, CRE has authorised Elengy and Fosmax LNG to develop the following unregulated activities:

- truck loading services at Montoir and Fos Tonkin terminals;[249] and
- LNG cargo transhipment service between two LNG tankers operated (i) by a dedicated subsidiary of Elengy, Elengy Hub & Expertise, at the Montoir terminal (the approval of the CRE was subject to the setup of a dedicated subsidiary[250]) and (ii) by an external service provider (Teekay Marine Solutions Ltd) at the Fos Cavaou terminal[251] (CRE considered that a subsidiary will be required if the activity becomes permanent).[252]

The Dunkirk LNG terminal enjoys a full but temporary exemption from third party regulated access and tariff regulation for the entire terminal capacity. Such exemption is granted for a period of twenty years from the commercial entry into service of the terminal). This exemption was granted to Dunkerque LNG by ministerial order of 18 February 2010[253] in accordance with the amendments requested by the opinion of the Commission dated 20 January 2010.[254]

LNG terminals do not need to be specifically authorised under the French gas regulation. However, LNG terminals are facilities subject to classification for environmental protection purposes and therefore their operation is subject to specific authorisations being granted by the State's local representative in addition to all other standard requirements. As LNG terminals are often located on the public domain belonging to port authorities, specific occupancy authorisations may also be required from port authorities.

Storage

Storengy, a subsidiary of ENGIE, and Terega are the two operators of storage sites in France.[255] The storage of natural gas in France is governed by the provisions of the Energy Code and is based on two key principles: non-discriminatory access of gas suppliers to gas storage facilities and an obligation for gas suppliers to contribute to the continuity of supply of natural gas through an obligation to store natural gas. Following various claims brought by various gas suppliers[256] against the existing gas storage system based on a negotiated access to storage facilities and the preliminary ruling issued by the European Court of Justice (see the section on *Gas storage* in the recent development article for more information),[257] the French Government has decided to modify the gas storage system and opted for a regulated access of authorised suppliers to storage facilities[258] with a principle of auctioning the storage capacities and regulation of storage prices.[259] The new system, implemented by Law no. 2017-1839 dated 30 December 2017 (also known as the Hulot Law), provides that the storage capacities provided by the storage operators are auctioned, and the difference between the auction revenue and the regulated income of the storage operators is compensated through the tax recovered by the natural gas transmission network operators. The CRE, as national energy regulator, is entitled to set out the methodology for establishing the tax and marketing methods for storage capacities.[260] The auction rules are approved by the CRE upon proposal of the storage operators and are published on their websites. If the Minister of Energy considers that, at the end of auction, the subscribed capacities are not enough to ensure the security of supply, it may, subject to prior approval of the CRE, impose on the suppliers (or the storage operators) to book additional capacities.[261]

As such, the new system maintains the obligation for the gas suppliers to subscribe the storage capacities on 1 November of each year.[262] The breach of such obligation may trigger penalties including the withdrawal of the gas supply licence.

On July 13, 2022, the CRE launched a public consultation n° 2022-05 regarding the changes of the marketing modalities of natural gas storage capacities, to obtain some insights, from the gas storage infrastructure operators, on the amelioration/simplification axes as part of proceedings related to the marketing of natural gas capacities. Such public consultation is open to any interested individual or company, until 5 September 2022.[263]

B.4 Oil and gas market entry

Natural gas suppliers must be authorised by the Minister for Energy to operate their activities.[264] The information to be provided to the minister is standardised and set, along with the authorisation process, by the Energy Code.[265] An authorisation is granted or refused depending on the technical, economic, and financial capacity of the supplier and the compatibility of the supplier's project with public service obligations.

Law No. 2019-1147 *relative à l'énergie et au climat* dated 8 November 2019 allows the ministry for energy to withdraw the authorisation if the supplier does not use it in a two consecutive years span.[266]

There is no such kind of authorisation regarding oil market entry.

B.5 Public service obligations and smart metering

Public service obligations (PSOs)

The law imposes public service obligations on all participants in the gas market. These obligations relate to the safety of people and facilities, the continuity of gas supply, the security of supply, the quality and price of the products and services supplied, environmental protection, energy efficiency, the valorisation of biogas, the balanced development of the territory, the emergency supply of gas to non-domestic customers and the continued supply to vulnerable people and the supply of gas at the special 'solidarity' rate.[267] Public service obligations are specified in the authorisations granted for the supply or transport of natural gas or in the concessions for the underground storage of natural gas.

Moreover, GRTgaz and GRDF[268] are each bound by specific public service obligations[269] that are set out in an agreement entered with the French State (the public service contract) on 11 July 2019.

Smart metering

Pursuant to the law, transportation and distribution operators are required to set up an interoperable metering mechanism favouring the active participation of the users.[270] The format of the project will be approved by the ministers for energy and consumption upon the proposal of CRE. In line with this provision, GRDF conducted a project, also known as the "*Gazpar project*", which commencement was approved by the CRE in 2011.[271] Following a first decision on 25 July 2013, the ministers for energy and for economic affairs definitely approved the overall implementation of this project on 23 September 2014.[272] A pilot deployment started at the end of 2015. The interoperable metering mechanism started in 2016 and is set to end in 2022 with the installation of 11 million smart meters.[273]

B.6 Cross-border interconnectors

Save LNG terminals, there are seven entry/exit points in France, managed either by GRTgaz[274] in the north and southeast or, by Terega[275] in the southwest of France:

- Dunkerque: entry point of gas coming from Norway via the Franpipe pipeline;
- Virtualys (formerly Alveringem and Taisnières H): entry and exit gas point from France to Belgium;
- Taisnières: entry points of gas coming from: (i) Groningen (Netherlands), (ii) Norway passing through Netherlands and Belgium in the Segeo pipeline and (iii) Zeebrugge via the Finpipe pipeline;
- Obergailbach: entry point of gas coming from Russia;
- Oltingue: entry and exit gas point from France to Italy (via Switzerland);
- Jura: exit gas point from France to Switzerland; and
- Biriatou and Larrau, together Pirineos: entry and exit gas point between France and Spain.

'Open seasons' were jointly conducted by Enagás, GRTgaz, Naturgás Energía Transporte and Terega in 2009 and 2010.

The transportation capacities between France and Spain were consequently reinforced in 2013 and 2015 at the Pirineos entry/exit point. Those capacities provide for 27% of the Spanish demand. The MIDCAT Project aims at reinforcing the North/South corridor by creating a new interconnection East of the Pyrenees.[276]

Recently, Elengy and its subsidiary, Fosmax announced the 'Open Season Fos Cavaou 2021'.[277]

In 2021-2022, GRTgaz held France's first national low-carbon and renewable hydrogen consultation (*Open Season pour une Infrastructure de transport d'hydrogène*). From 16 June to 16 September 2022, GRTgaz launched its first hydrogen call for expression of interest to confirm the economic interest in a hydrogen pipeline transport infrastructure around Valenciennes and extending to the border with Belgium (the network would be connected to its Belgian equivalent that Fluxys plans to develop in parallel around the city of Mons).

C. Energy trading

C.1 Electricity trading

Electricity can be traded on the over-the-counter market (OTC) or on the European Energy Exchange AG ("EEX").[278] Trading on the sub-markets of EEX may only be carried out or brokered by participants approved by the board of management of EEX.

The EEX operates spot and derivative trading: EPEX Spot SE[279] is a sub-market on which short-term trading in power for Germany, France, Austria, Switzerland, Belgium, Luxemburg, the Netherlands and United Kingdom takes place (the "Spot Market"). EEX Power Derivatives GmbH[280] provides a platform on which long-term trading of German and French power derivatives are traded (the "Derivatives Market").

In 2021, 7,405.7TWh were trading on the global power trading market, 4,568TWh were trading in European power derivative market and 629.5TWh were trading in the European power spot market.[281]

C.2 Gas trading

Natural gas can be traded bilaterally or on the French exchange market Powernext. Until 2020, Powernext managed the natural gas activities of the EEX Group under the PEGAS brand throughout Europe and offered notably spot and futures products, as well as spread products between those market areas to PEGAS market participants.

On 1st January 2020, Powernext was integrated into EEX. The natural gas market previously operated by Powernext via the PEGAS platform is now organized under the EEX rules for the regulated market[282]

All contracts concluded lead to physical deliveries on the title transfer points (*points d'échange de gaz* or "PEGs": ie, virtual gas exchange points).

The gas market operates under a single trading area called "Trading Region France". This single trading area operates a single entry/exit zone, divided into two balancing zones (GRTgas and Teréga) and a single virtual exchange point called "PEG".

This zone has been in operation since 2018, some new entry and exit zone adjustments were made in 2022.[283]

C.3 Introduction of EMIR and REMIT

In accordance with REMIT, French energy market participants are required to register to CRE through a consolidated register managed by ACER.[284] Failure to do so may lead to sanctions such as financial penalties, or a temporary ban on grid access or on the company's ability to carry out its activities.[285]

In 2013, the scope of the monitoring, enforcement and sanctioning powers of the CRE has been increased to apply specifically in the context of REMIT.[286] It should be noted that since 2006, the CRE has been empowered with the general mission of monitoring the transactions concluded between suppliers, dealers and producers.[287]

In relation to the public disclosure of inside information, the CRE has recently requested that operators of LNG terminals create a platform dedicated to the disclosure of inside information that may be held by their users.[288]

D. Nuclear

D.1 Industry structure

Current functioning of nuclear fleet as part of the energy crisis

In 2022, the French nuclear fleet comprises 56 operational nuclear reactors spread over 18 sites. It remains the first source of electricity production and consumption, with 360,7TWh produced in 2021 equivaling to 69% of total electricity production on the territory[289] despite low availability of the reactor fleet, at the end of 2021.

The commissioning of a new European Pressurised Reactor (EPR) at Flamanville (named "Flamanville 3") with a capacity of 1.650MW, operated by EDF[290] should have started in 2012 but is now expected for the beginning of 2023.[291]

The Energy Transition Law provides for a reduction of the share of nuclear energy in electricity generation to 50%, by 2035.

Today, thirty-two (32) French nuclear reactors are closed for scheduled maintenance due to unexpected corrosion problems. However, because of the current energy crisis, the French Government required EDF to quickly ensure a reactor restart program. EDF confirmed the recommissioning of twenty-eight (28) reactors by the end of 2022, then five (5) others in early 2023.

Actors of the French nuclear sector

Main actors of the nuclear market supervision in France

Government/ministerial services are the following:

- the Ministry in charge of Energy, through the Direction Générale de l'Energie et du Climat (DGEC), as well as the Direction Générale de la Prévention des Risques (DGPR) and the Service du haut fonctionnaire de défense et de sécurité (SHFDS);
- the Ministry in charge of Foreign Affairs;
- the General Secretariat for European Affairs, with technical support from the Euratom Technical Committee for inter-ministerial coordination of French positions in European bodies;
- the Ministry in charge of the Economy and Industry, with the General Directorate of the Treasury, the State Holdings Agency (APE) and the General Directorate of Enterprises (DGE); and
- the Ministry of Defence.

The DGEC prepares and implements, subject to the Nuclear Safety Authority (*Autorité de Sûreté Nucléaire* (ASN)) initiatives and powers, and the DGPR, the Government's decisions concerning the civil nuclear sector and participates in the preparation and adaptation of texts applicable to the sector.

In the area of nuclear safety, although Law no. 2006-686 of 13 June 2006, related to transparency and security in the nuclear field (TSN Law), now codified in the French Environmental Code, has given broad powers to the ASN, the government retains essential responsibilities for nuclear safety and radiation protection. This responsibility is exercised by the Nuclear Safety and Radiation protection Mission (*Mission Sûreté Nucléaire et Radioprotection* (MSNR)) attached to the DGPR.

DGEC also supervises ANDRA, FRAMATOME, ORANO (formerly AREVA), CEA, EDF and IRSN and monitors all companies in the civil nuclear sector.

Research organizations and nuclear industry players in France

The main organisations are the following:

- AREVA – is involved in the entire nuclear fuel cycle (mining, uranium conversion and enrichment, fuel assembly manufacturing, spent fuel processing) as well as in the design, manufacture and maintenance of nuclear reactors. Since June 2015 and under the impetus of the French government, AREVA has undergone a profound reorganisation based on the following principles: (i) refocusing AREVA on activities related to the fuel cycle, (ii) merging with EDF in the design of new reactors, reactor construction, fuel assembly manufacturing and maintenance services.

  The Ministry in charge of Energy participates in AREVA's governance in accordance with Decree no. 83-1116 of 21 December 1983, on AREVA, which stipulates that the Energy and Climate General Manager acts as the Government Commissioner.
- *Commissariat à l'Energie Atomique et aux énergies alternatives* (CEA) – a public research organization under the supervision of the ministers responsible for energy, research, industry and defence, carries out all research and activities necessary for the use of nuclear energy and the control of its effects.

- *Electricité de France* (EDF) – State-owned company (83,9%) which operates 58 nuclear plants spread within 19 sites and produces electricity on the French territory. EDF's fleet of nuclear power plants represents 89.1 % of EDF's total electricity generation. EDF has developed industrial cooperation with European operators in the form of generation allocation contracts which relate to the units of EDF's French nuclear fleet.
- *Institut de Radioprotection et de Sûreté Nucléaire* (IRSN) – placed under the supervision of the Ministers in charge of Energy, the Environment, Defence, Research and Health, the Institut de Radioprotection et de Sûreté Nucléaire was created in 2001. The IRSN carries out expert assessment and research missions in the following fields of nuclear safety and the transport of radioactive and fissile materials, the protection of man and the environment against ionizing radiation and the protection and control of nuclear materials.
- Orano – a company jointly and initially held by the French State (45.2%), AREVA SA (40%),[292] Japan Nuclear Fuel Ltd. (JNFL) (5%), Mitsubishi Heavy Industries (MHI) (5%) and the CEA (4.8%). This company has been created in January 2018 and results from the carve-of AREVA's activities relating to the nuclear fuel cycle (ranging from mining to decommissioning and including conversion, enrichment, recycling, logistics and engineering).[293] The French State purchased out Areva's remaining shares in Orano. The Order dated 23 September 2021 records the purchase from Areva by the French State of nearly 25,000 Orano shares.
- Framatome – a company jointly held by EDF (75.5%), Mitsubishi Heavy Industries (MHI) (19.5%) and Assystem (5%). This company has been created in January 2018 and results from the divestment of AREVA's former activities relating to the design, manufacturing and maintenance of nuclear reactors.[294]

D.2 Creation, operation and shutdown of nuclear facilities

TSN Law includes the main provisions applicable to nuclear facilities (basic nuclear facilities or "INB").[295] Rules regarding the creation and operation of an INB are detailed in the French Environmental Code.[296]

The creation of a nuclear facility is subject to the granting of an authorisation (a decree), upon consultation with the ASN. To be authorised to set up an INB, the operator must show that technical or organisational measures, taken or provided for from the beginning of the project (regarding its construction, operation and dismantling) will prevent or limit, to a sufficient degree, risks or drawbacks associated with an INB in relation to security, public health and safety, the protection of nature and the environment. The operator must also show that its financial and technical capabilities allow to adequately run the project when it might face with such issues.[297]

The authorisation to operate a nuclear plant is not limited in time. However, such a licence can be withdrawn if the plant does not meet the nuclear security requirements. In such case, there is a change in the operator or a substantial modification affecting the nuclear facility, a new authorisation shall be obtained.[298]

The French legal framework provides for the possibility (i) to review the nuclear plants every 10 years; and (ii) to impose new security requirements to the licensee.[299] Shorter review periods can be set out in the nuclear operation licence. The ASN holds broad powers of investigation and control of the nuclear plants' operation and may also impose additional prescriptions to protect public security and health.[300] Should the operation of a plant jeopardise the security, public health or the protection of environment, the Ministers in charge of Nuclear Security may suspend the operation of such plant or require the closing down and dismantling of the plant.[301] Furthermore, failure to comply with the imposed prescriptions may also give rise to administrative sanctions (fine and/or temporary closing down of the power plant) and criminal penalties (up to imprisonment).[302]

In practice, a service life of 40 years is considered as a particular milestone for a nuclear power plant, after which some components of the power plant, such as the vessel or the containment, requires particular attention because they are not replaceable. In 2017, the Fessenheim plant was the first of the existing plants under operation to reach the 40 years cap. The shut down and dismantling of the two Fessenheim nuclear plants occurred on 22 February 2020 for the first nuclear plant[303] and ton 29 June 2020 for the second one.[304] The commissioning of the Flamanville EPR is scheduled for 2023 at best.

The final shutdown and decommissioning of an INB is authorised by decree following consultation of the ASN.

D.3 Financing of nuclear costs

The "Programme Law" of 28 June 2006[305] provides a plan for radioactive material and waste management in France. The Programme Law also sets out the conditions for the organisation and the financing of radioactive waste management.

Notably, it provides a framework covering the evaluation and costs involved in the decommissioning of nuclear facilities and for the management of burnt fuels and radioactive waste and provides that assets dedicated to the hedging of provisions cannot be used for any other purpose by the operator and should be subject to separate accounting.

A decree sets out the implementation conditions of the Programme Law.[306] The operator shall evaluate costs according to five categories, including nuclear facilities decommissioning costs and management costs of used fuels. Different kinds of hedging assets are accepted within a certain percentage.[307] The operator must keep an updated register of current hedging assets. The operator's board of directors determines the framework of the hedging assets creation and management policy, in accordance with the assets' purpose and general principles of prudence and risk sharing.

The operator shall submit, to the authorities, triennial reports on the financing of nuclear costs. In light of these reports, the authorities may find that (i) the assessment of the dismantling costs, (ii) the calculation of the provisions or (iii) the amount, choice or management of the coverage assets, are insufficient or inadequate and instruct the operator to remedy the situation, failing that, to impose the allocation of additional/alternative assets together with penalty payments.[308]

D.4 Nuclear civil liability

The principles laid down in the Paris Convention[309] and the Brussels Convention[310] governing the nuclear civil liability have been implemented into French law.[311] To facilitate the indemnification of third parties, a mechanism of channelling of the liability on the operator of a nuclear facility, together with compulsory insurance coverage, has been designed. Since 2006, the maximum amount of compensation payable by a French operator under French law was capped at circa €91.5 million, and circa €22.9 million in case of nuclear incident occurring respectively within the perimeter of a nuclear facility and outside the perimeter of such a facility during transport.

In 2015, France decided to anticipate some of the provisions of the protocols amending the Paris Convention[312] and the Brussels Convention and has raised the liability caps up to €700 million and €80 million respectively, subject to the entry into force of the protocol.[313] An operator of a nuclear facility in France is therefore liable within a 10-year period for nuclear damages (including property damages and personal injuries/death).[314]

France is also a party to a Joint Protocol adopted in 1988 and which entered into force on 27 April 1992, harmonising the international nuclear civil liability principles between Paris Convention states and Vienna Convention[315] states. Therefore, an operator of a nuclear facility located in France is liable for all property damages and personal injuries/death suffered on the territory of a Paris Convention States, or a Vienna Convention State (provided that such Vienna Convention State is also a party to the Joint Protocol) resulting from a nuclear incident having occurred inside its nuclear facility.[316]

E. Upstream

N/A

F. Renewable energy

Objectives

France's target for its share of energy produced from renewable sources in relation to its gross final consumption of energy is set at 23% of the French gross final electricity consumption by 2020, and 33% by 2030 in the Energy Transition Law. As of 31 December 2021, the use of renewable energy covers 249% of gross final electricity consumption.[317] The main renewable energy sources in France are hydropower, wind, solar and biomass. Both onshore wind and solar electricity generation are highly fragmented due to the caps that apply to the installed capacity of subsidised facilities.

Legal framework overview

In accordance with the Energy Transition Law, France's target for its share of energy produced from renewable sources in relation to its gross final consumption of energy is set at 23% in 2020 and 33% in 2030. As of 31 December 2021, the percentage of electricity generated from renewable sources equals 24.9% of the total electricity consumed.[318]

In order to achieve the targets, set out in the Energy Transition Law, the PPE also sets the following quantified targets of installed renewable energy power: 53GW in 2018 and 71-78GW in 2023.[319]

On 28 June 2014, the European Commission published its guidelines on State aid for environmental protection and energy (the "Energy Guidelines"),[320] whose implementation deadline was set on 31 December 2015.

France has introduced the main principles of the Energy Guidelines and redefined the architecture of its support mechanisms for renewable energy sector via the Energy Transition Law and implementing decrees of May 2016[321] (the "Energy Transition Reform"). However, France has not fully complied with the EU deadlines relating to the Energy Guidelines of 1 January 2016 and 1 January 2017. France's support regimes are therefore undergoing a transitory phase.

Former support regimes

The former support regimes were solely based on the obligation imposed on EDF and some other local distribution operators to enter into a power purchase agreement ("PPA") based on a feed-in tariffs regime (FiT). The FiT regime was implemented by ministerial orders (one per source of energy) or by call for tenders. Nearly every renewable sector had a specific FiT order, and the benefit of the FiT was materialised by the issuance of a power purchase obligation certificate (*certificat ouvrant droit à l'obligation d'achat*, called "CODOA"). The calls for tenders organised until 2016 have mostly focused on solar, offshore wind and biomass installations.

It should be noted that the FiT PPA can now be entered into or assigned to an entity that has obtained a specific certification from the authorities.[322] Enercoop and Hydronext were the two first entities that have obtained this certification at the end of 2016; since then, 6 additional entities have obtained this certification (L'Union des Producteurs locaux d'électricité, BHC Energy,Energies Libres Grands Comptes, Joul, Direct énergie, BCM Energy, GEGE Source d'énergies, NLG, AXPO Solutions AG, Alpiq Energie, TOTAL Flex).[323]

FiT schemes are financed through the CSPE levied on all end customers (see section A.6). The government did not notify the legal framework setting out FiT for renewable energy to the European Commission.

On 28 May 2014, the *Conseil d'Etat* invalidated a 2008 ministerial order setting out FiT for energy produced by onshore and offshore wind turbines (the "2008 Wind Order"), on the basis that it constituted illegal state aid.[324] This judgement is based on a preliminary question referred by the *Conseil d'Etat* to the ECJ, whereby ECJ determined, in a judgment dated 19 December 2013,[325] that the FiT set by the 2008 Wind Order was financed through state resources. In a new decision dated 15 April 2016, the *Conseil d'Etat* ordered the French government to recover interests payable by wind energy producers on the portion of the payments made to them constituting illegal state aid.[326]

In the meantime, France notified the 2008 Wind Order to the European Commission and in its decision of 27 March 2014,[327] the European Commission came to the conclusion that the FiT of the 2008 Wind Order constituted a state aid regime compatible with EU law (based on the 2008 Energy Guidelines). At the same time, the French government issued a new FiT order applicable to onshore wind farms dated 17 June 2014, effective on 2 July 2014[328] (the "2014 Wind Order"). This order also benefits of the Commission's decision as it is based on the same mechanisms.[329]

French FiTs for other renewable energy projects (solar, biomass, etc) enacted before 2016 are also at risk of being classed as illegal state aid in so far as they have never been notified to the Commission and are based on the same financing rules as the 2008 Wind Order.

New support regimes

Support mechanisms for the renewable energy sector have been recast by the Energy Transition Reform by:

- maintaining a support mechanism based on FiT (with a limited scope);[330]
- introducing an *ex-post* contract for difference support mechanism whereby electricity generated from renewable sources is first sold on the market (eg, on EPEX or through a broker called "*agrégateur*"), and then a variable premium (called the "Premium") is paid to the electricity generator by EDF based on a dedicated contract (the "Premium Contract"),[331] ensuring a reasonable return on the invested capital;
- maintaining two systems for the allocation of the two above mentioned support mechanisms, namely: (i) ministerial orders and (ii) a reformed tender system.

It should be noted that the regime for obtaining a PPA based on a ministerial order is nearly identical for both FiT and Premium regimes,[332] for example:

- a CODOA is no longer required in both cases; the generation installations must now be certified at the commissioning stage[333] and are subject to periodic reporting and controls (these procedures are cumulative with REMIT's obligations and have been detailed by a decree of December 2016);[334] and
- the same legal regime is applicable to both the FiT PPA and the Premium Contract (ie, qualification of administrative contract, only bidding from the signature of both parties, etc.).[335]

Regarding bidding processes, the call for tenders has been reorganised into a single procedure (the accelerated procedure has been deleted) and a new procedure, inspired by the public procurement mechanisms, has been implemented: the competitive dialogue procedure.[336] Based on the PPE, France will implement multi-annual calls for tenders specific to each renewable energy source. In this regard, France notified the European Commission of its support for renewable energy through a call for tender system on 17 March 2021.[337]

Bio-natural gas

In view of supporting the injection of bio-natural gas into the natural gas grid, specific FiT have been introduced in November 2011 which have been repealed and replaced by Decree on 30 December 2015.[338] The FiT were governed by the order dated 23 November 2011,[339] as amended by the order dated 26 April 2017[340] until December 2020. The current FiT are governed by a new order dated 23 November 2020[341] and then an order dated 13 December 2021.

Decree no. 2021-1273 dated 30 September 2021 has introduced some principles for the call for tenders but also introduced the foundations for support regimes to biogas via CfD mechanisms.

On 14 April 2022, the CRE has approved the draft specifications for the call for tenders for the construction and operation of biomethane production facilities which aims to accelerate the development of biogas production capacities. This support scheme is applicable to new facilities located in mainland France that inject into a natural gas network the biomethane produced (i) from biogas captured at non-hazardous waste storage facilities from household and similar waste, or (ii) from the methanization in digesters of non-hazardous products or waste. The awarded projects benefit from a purchase obligation contract for a period of 15 years and have a period of 3 years from the date of their designation to complete their installation and start their purchase contract. The specifications of this call for tender have now been published on the CRE's website. However, the first period for bidding has been suspended and the new dates have not yet been communicated.

In addition, the bio-natural gas injected into the natural gas grid may benefit from a guarantee of origin[342] upon request by the purchaser (ie, the gas supplier).[343] One bio-natural gas guarantee of origin is granted in respect of each unit of energy produced (ie, one guarantee of origin per megawatt hour).[344] The bio-natural gas guarantees of origin are recorded in a national registry managed by GRDF.[345]

Single environmental authorisation

Following local trials, an *ordonnance*[346] and two decrees[347] dated 26 January 2017 were introduced implementing the single environmental authorisation as of 1st March 2017. It mainly applies to:

- facilities, works and operations subject to a water permit;
- facilities regulated under environmental protection rules (*Installations Classées pour la Protection de l'Environnement* (ICPE)); and
- certain projects subject to an environmental assessment.

When applicable, the single environmental authorisation replaces and encompasses multiple authorisations,[348] including:

- the energy operation licence set out in Article L. 311-1 of the Energy Code;
- the approval for the treatment of waste pursuant to Article L. 541-22 of the Environmental Code;
- ICPE registration/declaration; and
- for wind farms only, authorisations pertaining to air navigation, military easements and easements for surroundings of historic monuments and remarkable heritage sites. Onshore wind farms are also exempt from obtaining a building permit.[349]

The competent administrative authority to issue the single environmental authorisation is the *Préfet* of the department in which the project is located. The procedure takes place on a tight schedule divided into three stages:[350]

- examination (extendable period of four months);[351]
- public inquiry (three months);[352] and
- decision (extendable period of two months).[353]

F.2 Renewable pre-qualifications: the competitive dialogue procedure

The Decree no 2016-1129 dated 17 August 2016 created a new tendering procedure for renewable energy projects called competitive dialogue procedure. This procedure applies essentially to offshore projects. Indeed, the purpose of the competitive dialogue is to define or develop solutions to meet complex needs such as offshore wind or offshore floating wind projects.

This procedure includes a pre-qualification phase that allows the French Minister in charge of energy to select the most suitable candidates to respond to the tender. This phase starts with the preparation of the consultation documents, which are composed of:[354]

- the purpose of the competitive dialogue;
- the provisional timetable of the procedure;
- the requirement concerning the technical and financial capacities of the candidates as well as the supporting documents during this pre-qualification phase;
- the criteria, in decreasing order of importance, for selecting the offers at the end of the competitive dialogue.

The consultation documents are prepared by the Minister in charge of energy and then forwarded to the Energy Regulatory Commission ("CRE") for its opinion[355] before publication in the Official Journal of the European Union.[356] In addition to the above-mentioned elements, the publication notice must also include:[357]

- the terms and conditions for submitting applications for the competitive dialogue.
- the minimum number, which may not be less than three, and maximum number of candidates admitted participating in the procedure, as well as the objective and non-discriminatory criteria for reducing the number of candidates.
- the deadline for submission of applications.

CRE examines the technical and financial capacities of the candidates in view of the evaluation methods defined in the consultation document and then sends the Minister the list of applications it proposes to select and that of the candidates not selected, together with the reasons for rejection.[358] The pre-qualified candidates are invited to the competitive dialogue to draw up the specifications based on which they will have to submit a final offer.[359] The Dunkirk area was the first to benefit from this procedure for offshore wind power installations. The pre-qualification phase was open from 15 December 2016 until 6 March 2017.[360] CRE selected eleven candidates to participate in the competitive dialogue based on their technical and financial capacities (past experiences, equity capital capacity, balance sheet etc.).[361] At the end of the procedure, eight candidates submitted each an offer for the offshore wind power.[362]

F.3 Biofuel

The legal regime applicable to biofuels has been created by Ordinance no. 2011-1105 dated 14 September 2011[363] and is codified in the Energy Code.[364] This Ordinance transposes Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 in the field of renewable energy and biofuels.[365] This European Directive sets binding targets for Member States relating to the share that energy from renewable sources must represent in the gross final energy consumption and in the transport energy consumption. In accordance with these objectives, France has committed to including a share of energy from renewable sources in the final energy consumption in all modes of transport of:

- at least 10% in 2020; and
- at least 15% in 2030.[366]

In addition, the use of biofuels (instead of fossil fuels) shall lead to a reduction in the production of greenhouse gas emissions of at least 50% for installations commissioned before 5 October 2015 and of at least 60% for installations commissioned from 5 October 2015 onwards.[367]

To calculating whether the above-mentioned targets are reached, only biofuels meeting certain sustainability criteria shall be taken into account.[368]

However, due to certain controversies related to the development of biofuels, a new European Directive dated 9 September 2015[369] has amended this legal regime in order to restrict the share of traditional biofuels and consequently limit the conversion of agricultural lands into crops intended to produce these traditional biofuels. Pursuant to this Directive, the share of first-generation biofuels (as opposed to advanced biofuels) shall not exceed 7% of the final energy consumption in transport in 2020. The PPE includes the same maximum objective.

In addition, the PPE set a target of incorporation of advanced biofuels into the final energy consumption in the transport sector. These targets were the following:

- for the fuel sector, 1.6% in 2018 and 3.4% in 2023;
- for the diesel sector, 1% in 2018 and 2.3% in 2023;[370]

The PPE has increased these targets to reach respectively for the fuel and diesel sectors 3.8% and 2.8% in 2028.[371]

F.4 Electric mobility

Developing electric mobility and equipping the French territory with a complete and homogenous network of charging stations for electric vehicles has become a key strategic axis of the French ecological transition.

In that respect, France has set out the following key targets:

- the Energy Transition Law provides that at least 7 million charging stations for hybrid and electric vehicles should be built by 2030;[372]
- the initial PPE for 2016-2019 set out an objective of 2.5 to 3 million electric and hybrid vehicles by 2025 and of 3.6 to 4.3 million electric and hybrid vehicles by 2030.[373] The current PPE for 2019-2028 now sets a higher target of 35% share of electric passenger cars and 10% of plug-in hybrid passenger cars in sales (27% and 7% respectively in 2028).[374] Law no. 2019-1428 on orientation of mobilities[375] and the PPE contemplates the end of the sale of diesel vehicles by 2040;

To achieve these targets, certain entities (eg State, local authorities, car rental companies or taxi companies) shall now acquire a minimum percentage of low emission vehicles when they come to renewing their respective fleet.[376] This requirement should be extended to any private corporations owning more than 100 vehicles by the draft bill relating to mobility (see below).

In parallel, the deployment of charging infrastructures has been fostered through:

- the granting of aids by the ADEME (*Agence de l'Environnement et de la Maîtrise de l'Energie*) to support projects developed by local governments: as of 30 June 2018, the ADEME supports 76 projects for a total amount of aid of circa €56 million;[377]
- the granting, from 1 September 2014 to 31 December 2019, of tax credits to individuals installing charging stations at home;[378]

- the adoption of a decree dedicated to enable the harmonised development of charging stations in terms of power, interoperability and access to the stations.[379]

The aim of the French government is to continue accelerating the installation of charging stations (15,000 new charging stations per year with a total number of stations of 55,000 to 65,000 by the end of 2020).[380] To this end, the Law no. 2019-1428 on orientation of mobilities provides for the following main incentive measures:[381]

- reduction in the costs for the connection of the charging stations to the electricity grid by increasing from 40% to 75% the part of these costs paid through the TURPE tariffs from 1 January 2022;
- obligations for developers to pre-equip car parks located in new or refurbished buildings with charging stations from March 2021 onwards; and
- obligations for car parks located in non-residential or mixed buildings to include at least one charging station from 1 January 2025 onwards.

G. Climate change and sustainability

G.1 Climate change initiatives

In 2007, France launched roundtable discussions focused on green issues (ie, the Grenelle Environment Forum). The commitments resulting from this forum have been implemented at a legislative level through the adoption of two Laws in 2009 and 2010. As detailed in the introduction, the Energy Transition Law was issued in 2015 to set out the national policy for implementing the energy transition in France and implements very challenging targets for France. Since that time, more recent developments have happened, such as the Citizen's Climate Convention. In April 2019, the President of the Republic Emmanuel Macron announced, at the end of the Great National Debate, a platform for a Citizens' Climate Convention.

The Citizens' Climate Convention is a French citizens' assembly that brings together 150 citizens selected in a draw from the French population. It aims to "*define structuring measures to achieve, in a spirit of social justice, a reduction of greenhouse gas emissions by at least 40% by 2030 compared to 1990*". The first meeting of the Convention occured in October 2019 at the Palais d'Iéna headquarters of the EESC (Economic, Social and Environmental Council).

Since 2011, the Government has been publishing Climate Change Adaptation Plans, updated regularly. The first Climate Change Adaptation Plans ran from 2011 to 2015, and we are currently heading towards the end of the second which started in 2018 and will end this year[382]

In its report published in June 2020, the Convention formulated 149 proposals. President Emmanuel Macron committed to submit them to Parliament or to a referendum, with the exception of three of them. These proposals were transposed in the French's legislative and regulatory frameworks through the ecological defence council, the economic recovery plan, the finance law for 2021, and the law fighting against climate change and strengthening resilience to its effects of 22 August 2021.[383]

Moreover, for the year 2021 as a whole, 37 billion euros of expenditures (tax and budget combined) were set out in the draft budget bill by the French state in favour to the climate. €7 billion were spent towards renewable energies, and specifically towards renewable electricity. Some of the other areas of spending include financial aids for eco-efficient building renovation, reduced VAT on such construction work (1.2B), renovation of public buildings, funding of transportation means other than road-based, etc.[384]

On 7 June, 2022, the European Commission announced the first 118 regions and European local authorities to have signed the Charter for the "Adapting to Climate Change" mission, amongst which 5 French regions: Île-de-France, Occitanie, Provence-Alpes-Côte d'Azur, Normandie, Nouvelle-Aquitaine and the city of Paris. "Adapting to Climate Change" is one of the 5 EU missions in the research and innovation programme "Horizon: Europe", which aims to help about 150 local authorities to "better understand, prepare and manage climate-related risks and develop innovative solutions to reinforce their resilience" by 2030.[385]

On 14 June, 2022, France's Council of Ministers discussed an anticipated heatwave and planned long-term measures to adapt the country to the consequences of climate change. The general idea is to make French cities green again: trade concrete for trees to lower the temperature in urban areas, create canopies to shelter those areas from the sun, create living walls, etc. For this programme to viable, a 500 million euros fund will be established to assist willing local authorities to finance their actions. Moreover, the procedures regarding those operations will be simplified, and local authorities will also be assisted by the study center CEREMA for risk, environment, mobility, and planning, as well as agency for ecological transition ADEME and French Deposits and Consignments Fund (*Caisse des dépôts et consignations*) for loans.[386]

In November 2020 and October 2021, the French State, as a legal entity represented by the government, was convicted for failure to respect its undertakings to fight climate change. More precisely, both cases were brought by NGOs and targeted French governments from 2015 to 2018 (ie, François Hollande and Emmanuel Macron's presidencies) for their failure to not do enough to limit GHG emissions during this period.[387]

G.2 Emissions trading

The first EU emissions trading system ("ETS") directive was transposed into French law in 2004.[388] Two allocation plans (2005-2007 and 2008-2012) were adopted on this basis.

The New EU ETS Directive has been transposed into French law, by an *ordonnance* dated 28 June 2012.[389]

The fourth allocation plan ("PNAQ IV") for the period 2021-2030 was adopted, on the basis of the transposed New EU ETS Directive, by an *Ordonnance* dated of 9 October 2019.[390] A Decree was subsequently enacted to set out the allocation rules of these quotas.[391]

This allocation plan modifies the existing system by (i) introducing a strengthening of the climate ambition to reach – 43% of emissions in 2030 compared to 2005,[392] (ii) improving the allocating method of free allowances in order to take into account technical progress and to adapt the allocation more dynamically to variations in companies' activity.[393]

The penalties have also been adapted to make the system more effective.[394]

Health care facilities, if they implement equivalent emission reduction measures, and small emitters, except for power generation facilities, are exempted from the allowance allocation scheme.

G.3 Carbon pricing

Introduction

Reducing greenhouse gas ("GHG") emissions is an imperative for France, which is a party to the Paris Agreement. The Paris Agreement sets the climate target of limiting global temperature increase to well below 2°C. In the French legal framework, this objective is outlined in several other objectives that have a legislative force, such as reducing GHG emissions by 40% by 2030 compared to 1990 levels, as specified in the climate and resilience Law of 22 August 2021.[395]

However, to fulfil its climate commitments, France must shift to a low-carbon economy. Therefore, France implemented tax incentives to send clear signals about the benefits of reducing carbon emissions and the cost of GHG emissions to society. These taxes also incentivise the adoption of carbon-neutral lifestyles, notably by using renewable energy in order to accelerate the clean energy transition. Consumption taxes on fossil products and the ecotax are two instruments of France's carbon pricing strategy.

Ecotax

The ecotax (or ecological *malus*) was created by Article 63 of the Amending Finance Law for 2007 no. 2007-1824 of 25 December 2007.[396] It is an additional tax on vehicle registration certificates. It was implemented in France on 1 January 2008.

The ecotax is paid at the issuance of a first registration certificate for the purchase of certain polluting vehicles.

It applies, depending on the characteristics of the vehicle, if the carbon dioxide emissions ("CO_2") or the engine rating for tax purposes of vehicles exceeds the threshold set by Article 55 of the budget law for 2021, ie, 128 g/km of CO_2 for the year 2022.[397]

Today the amount of the ecotax is of €50 for 128 g/km of CO_2. The aim of the ecotax is to sanction the purchase of a new vehicle deemed to be polluting.

Climate-energy contribution

France's carbon pricing strategy also relies on the implementation of the Climate-Energy Contribution (CEC), also known as the "carbon tax". This mechanism has been in place since 1 January 2014 and was created by Article 32 of the Finance Law no 2013-1278 of 29 December 2013 as part of the national low-carbon strategy (SNBC). Its evolution is outlined on a government website, with indicators such as the number of units sold per month, the average price and proceeds – for example in June 2022 83,500 units were sold for an average price of 84.45 and the proceeds were €7.051.575.[398]

The CEC is not a tax *per se* but a method of calculating domestic consumption taxes in relation to the CO_2 content of energy products.[399] It is designed to deter consumers from consuming or adopting GHG-emitting products or behaviours. This contribution is paid by individuals and companies and added to the final price of petrol, diesel, fuel oil or natural gas.

The CEC is calculated through different methods:[400]

- downstream: it is calculated according to the CO_2 emissions induced by the production and distribution of the product or service.
- upstream: it is levied on the final consumption of fossil fuels (eg, final price of petrol, diesel, fuel oil and natural gas).

The amount of the CEC, initially set at €7 per ton of CO_2 in 2014, is revised upwards each year. Thus, the level of the tax increased to 14.50 € per ton of CO_2 in 2015, 22 € per ton of CO_2 in 2016 and 30.5 € per ton of CO_2 in 2017. In 2022, the carbon tax was set at 44.6 € per ton of CO_2 as provided for in the 2018 budget law. The Energy Transition Law for Green Growth of 17 August 2015 set a target of €100 per ton of CO_2 in 2030.[401]

The Climate-Energy Contribution is part of the domestic consumption tax on energy products ("TICPE" for *Taxe Intérieure de Consummation sur les Produits Energétiques*, in french), which is an indirect tax on various petroleum products (fuel oil, petrol, etc.) calculated in proportion of their volume or weight at the time they are placed on the market. It is also including the domestic consumption tax on natural gas ("TICGN" for *Taxe Intérieure de Consommation sur le Gaz Naturel*) and in the domestic tax on coal consumption ("TICC" for *Taxe Intérieure de Consmmation sur le Charbon*).[402]

CEC revenues amounted to €6.4 billion in 2017. A part of the associated domestic consumption taxes revenues is directly reinvested in the financing of renewable energy.

However, several industries benefit from exemptions on the payment of domestic consumption taxes. Some of these exemptions were made mandatory by an European directive, but the majority are defined at a national level. The exemptions defined at national level consist of partial refunds of domestic consumption taxes. They concern essentially the transportation sector (air, maritime, road).[403]

Offsetting of GHG emissions[404]

The aim of GHG offsetting is to finance projects that store CO_2 or reduce GHG emissions. To fulfil their offset obligation, operators use carbon credits. These are documents issued as a result of an offset project that certify that the operator has removed or avoided CO_2 emissions. A carbon credit is a unit equivalent to one tonne of CO_2 avoided or sequestered. The "Label Bas Carbone" projects carried out in France can also be used to meet the offset obligation.

The Climate and Resilience Law[405] introduced the obligation for operators of aircraft subject to the EU Emissions Trading Scheme (EU ETS) to progressively offset their GHG emissions from domestic flights or else face penalties. At the moment, flights between metropolitan France and the overseas departments and regions are not subject to the EU ETS. Consequently, they are not included in this scheme. For the year 2022, operators must offset 50% of their emissions, this carbon offset obligation will increase to 70% in 2023. By 2024, operators will be required to offset all of their emissions.

Decree no. 2022-667 of 26 April 2022,[406] specifies that the obligation concerns operators of aircraft generating more than 1,000 tonnes of CO_2 per year on the national territory.
The operators must now submit to the Ministry of Ecological Transition and Territorial Cohesion, by 31 March each year at

the latest, a declaration on the previous year's emissions and, before 1 June, a compensation report to prove the reduction and sequestration of these declared emissions. In the event of non-compliance with the obligation to offset, the fine amounts to €100 per tonne of GHGs not offset by the operator. The fine also applies in the event of failure to submit the offset report.

Moreover, a non-mandatory option is available too, in the form of voluntary carbon markets. Carbon markets are growing rapidly and have become increasingly important over the past few years, exceeding USD 1 billion in November 2021.[407] The French government is even encouraging farmers to resosrt to it[408] which goes hand in hand with the creation in 2019 of a Low-carbon Label as a part of a National Low-Carbon Strategy.[409]

The recent Decree no. 2022-982 of 1 July 2022, regarding GHG emission assessments amends the environmental code to align it with the provisions of Law no. 2019-1147 regarding energy and climate. It makes it possible to draw up a consolidated GHG emissions report for all the companies in a group, without limitation to only those companies with the same Tier 2 French activity nomenclature.[410]

G.4 Capacity market

Development of the capacity mechanism

France used to be an energy-only market. Following a report on the issues generated by the increase in peak power consumption, the NOME Law implemented a "capacity" mechanism, whereby electricity suppliers must prove their ability to meet their customers' needs at any time and at peak times through the acquisition of "guaranteed capacities". These obligations for the suppliers are provided by Articles L. 335-1 to L. 335-6 of the French Energy Code.

In 2013, the capacity mechanism obligation has been extended to large electricity consumers who acquire electricity directly on the wholesale market. Such consumers can however transfer the capacity obligation to its electricity supplier. Since 2015, the supplier can also transfer its capacity obligations to its consumer.

The capacity mechanism incentivises peak load management plans. Suppliers are assigned capacity obligations based on their customers' actual consumption during peak periods. The supplier may obtain these guaranteed capacities from:

- electricity producers, operating power plants in France, who are required to obtain a certification of their installations' generation capacity,
- consumers who can request certification of their ability to curtail their consumption at peak period (ie, the demand response capacities).

RTE oversees calculating and controlling the electricity suppliers' obligations regarding guaranteed capacities, as well as certifying and controlling the capacities of the electricity producers/consumers. Fines are used in order to encourage suppliers to comply with the guaranteed capacities requirements.

These guaranteed capacities can be sold and exchanged; consequently, a market for these capacities will emerge. However, in 2012 the French competition authority has raised serious doubts on the impact of the capacity mechanism on the structure of the electricity supply market.

The broad parameters of this capacity mechanism are provided in the implementing Decree adopted on 14 December 2012,[411] partly codified since 2016 in the Energy Code. The decree provides for a large set of rules to be adopted by the Minister and by the CRE to determine the calculation methods, the terms and conditions of capacity certifications, and the overall methods of control and sanctions.[412] RTE submitted a first set of rules on 6 May 2014. Following the positive opinion of the CRE on 28 May 2014, these rules were adopted by a ministerial order on 22 January 2015.[413]

Throughout 2015 and 2016, new capacity mechanisms were under scrutiny for their compliance with state aid rules. On 9 September 2015 the Conseil d'Etat rejected a state aid claim against the implementing Decree of 14 December 2012, affirming that no State resources are involved.[414] However, it decided to stay the proceedings and to submit a question for European Court of Justice's preliminary ruling regarding the compatibility of the capacity mechanism with principles of the free movement of goods. However, following the withdrawal of the claim by the claimant (ANODE), the Conseil d'Etat decided on 16 March 2016 to withdraw its request for a preliminary ruling and the case has been removed from the Court Register. Later, in its decision on 13 May 2016, the Conseil d'Etat invalidated some provisions of the implementing decree (ie, provisions on the certification of the capacities) on procedural grounds.

At the same time, the Commission launched a state aid sector inquiry into national capacity mechanisms involving France along with other countries. As a result of exchanges with Commission, the French Government agreed to amend the existing rules to ensure its compliance with EU state aid framework, and notably to prevent market manipulations and to open the capacity market to providers located in neighbouring Member States. On 14 November 2016, RTE submitted to the CRE a new set of rules, considering the modifications undertaken by the French Government. The CRE approved the modifications on 24 November 2016 and the rules have been officially adopted on 29 November 2016.[415] French capacity mechanism system has been validated by the Commission for 10 years.

French capacity mechanism has been amended by a Decree of 15 November 2018[416] to take into account the remaining European Commission's requirements that have presided over the abovementioned validation of the capacity mechanism. In particular, the Energy Code has been revised to (i) include capacities provided from other Member States and to (ii) create a new tender mechanism whereby selected capacities providers shall benefit from a 7-year contract providing for a guaranteed price in exchange of the maintaining of their capacities. On that basis, a new set of rules has been adopted on 21 December 2018.[417] Later, these rules were amended in 2019[418] and 2020.[419] The latest version of the rules was adopted by an Order dated 21 December 2021.[420] The main amendments aim at: (i) making the mechanism easier to understand; (ii) improving the efficiency of the mechanism with regard to its objectives; (iii) facilitating the day-to-day handling of the mechanism by the stakeholders; (iv) reducing the financial burden on participants in the mechanism; (v) ensuring the compliance of the mechanism with the European regulatory framework.

At the end of the seventh auction (13 December 2018) relating the French capacity mechanism for delivery year 2019, the guaranteed capacities were exchanged at a price of €18,046 per MW. And at the end of the first auction (21 March 2019) relating the French capacity mechanism for delivery year 2020, the guaranteed capacities were exchanged at a price of €20.001 per MW.

At the end of the sixth auction (10 December 2020) relating the French capacity mechanism for delivery year 2021, the guaranteed capacities were exchanged at a price of EUR 39.095 per MW.[421]

On August 24th, 2021, Law no. 2021-1104 was published, aiming to combat climate change and strengthen resilience to its effects. Also known as the "Climate and Resilience" law, it implemented some of the Citizens' Convention for the Climate's proposals. Amongst these were provisions allowing the possibility of using tendering procedures to facilitate the development of the electricity storage sector.[422] Moreover, to ensure a steady electricity supply, France also implemented a cross-border contributions mechanism.

This mechanism works amongst "interconnected States" on the basis of conventions and important terms like the overall value of cross-border contributions, the distribution coefficients of this overall value per State, and the security coefficient have to be decided at least four years before the start of the delivery year. Those provisions can be found in more details in Articles R. 335-9 to R. 335-23 of the Energy Code.

H. Energy transition

H.1 Overview

France's ambitions to combat climate changes has risen through years by introducing new rules for energy transition.

No major legislation has been announced since the 26th Conference of the Parties to the United Nations Framework on Climate Change (COP26) The major last legal initiative is the Law no. 2021-114 dated 22 August 2021 on tackling climate change and strengthening resilience to its effects (Climate and Resilience Law).

As a result, most of the following commitments undertaken by France at the COP26 were either (i) already set out in the Climate and Resilience Law or (ii) already provided for in other legal texts previously adopted during President Emmanuel Macron's five-year term, namely:

- Oil and gas production phase-out: this commitment was already provided for in Law no. 2017-1839 dated 30 December 2017 putting an end to the research and exploitation of hydrocarbons.
- Ending funding fossil fuels abroad without carbon capture technologies and redirecting the funds from these investments to renewable energy.
- Ending deforestation by 2030: under the French climate plan dated 5 July 2017 (axis 15th),[423] France had already committed to publish a national strategy to stop the import of forest or agricultural products contributing to deforestation. As part of this national strategy, France has undertaken to implement a wide range of measures to end the import of unsustainable forest or agricultural products contributing to deforestation by 2030. These measures are in line with the European Union's objectives, to which France committed in 2008, of halving gross tropical deforestation from current levels by 2020 and halting global forest cover loss by 2030.[424]
- Reducing methane emissions: this objective is already captured by the French national low carbon strategy introduced by Law no. 2015-992 dated 17 August 2015 on the energy transition for green growth in 2015, which aims to reach carbon neutrality by 2050.
- Increasing France's contribution to climate finance to EUR. 6 billion per year. The French Development Agency (*Agence française de développement*) is implementing France's contribution to the €100 billion target, which France raised in December 2020 to €6 billion of climate financing per year for developing countries, one third of which is dedicated to adaptation. During the COP26, the French Development Agency published for the first time a report on the "Taskforce on Climate Financial related Disclosure" (TCFD) that highlights its transparency efforts and the central role given to financial climate opportunities and risks in its governance, strategy and dialogue with its clients and partners.[425]
- Accelerating investment and international cooperation for green electricity networks.
- Supporting the "Glasgow Breakthrough" to develop innovation and clean technologies affordable for developing countries by 2030.

Reducing emissions from the aviation sector: in this respect, regarding all flights within the French territory, the Climate and Resilience Law provides that airlines shall offset (i) 50 % of GHG emissions as from 1 January 2022 and (ii) 100% of GHG emissions by 1 January 2024. In January 2022, the Ministry of Ecological Transition submitted for public consultation a draft of decree specifying the regulatory framework applicable to this obligation.[426]

H.2 Renewable fuels: hydrogen

The French hydrogen strategy: background and objectives

Law no. 2015-992 dated 17 August 2015, *relative à la transition énergétique pour la croissance verte*,[427] empowered the French government to develop a "*plan for the storage of renewable energies using decarbonated hydrogen*".

France's hydrogen strategy, initially set out in the 2018 Hydrogen Plan, was recently renewed as part of the 2020 France Recovery Plan. The strategy focuses mainly on supply side policies and there are several funding programmes in place to develop hydrogen across France.

Within the scope of France Recovery Plan 2020, the Government has committed to investing €2 billion in the near term (up to 2022) and €7.2 billion in the longer term (up to 2030) to deploy its hydrogen strategy. The three key principles are the decarbonation of hydrogen used in the industry (greening and grey hydrogen), the development of hydrogen-fuelled heavy-duty vehicles and infrastructure and the support in research, innovation, and skills development.[428]

The core objective is greening the use of grey hydrogen by creating a French electrolysis sector by:

- developing a French electrolyser sector with a goal of 6.5GW of electrolyser capacity by 2030 (eventually powered by renewable sources);
- establishing a regulatory framework to support green hydrogen projects; and

- targeting 20-40% of hydrogen to green hydrogen in the industrial sector by 2030.[429]

The Multi-Annual Energy Programme 2020 (the "PPE") sets out the strategy for developing clean hydrogen and using it in the industrial, energy and mobility sectors.[430]

Legal framework relating to the introduction of hydrogen

The French Parliament, under Article 52 of Law no. 2019-1147 dated 8 November 2019 (*related to energy and climate*), empowered the Government to set up a legal framework for hydrogen.

From a regulatory perspective, on 17 February 2021 the Government issued an ordinance aimed at regulating hydrogen production in France (the "Hydrogen Ordinance").

The Hydrogen Ordinance supplements the French Energy Code with a new Title VIII entitled "*Provisions relating to hydrogen*".[431]

Three types of hydrogen

Hydrogen is not an energy source but "a chemical element that must be produced before it can be used".[432] The Hydrogen Ordinance defines it as a "gas composed, in a proportion determined by order of the Minister responsible for energy, of dihydrogen molecules, obtained after implementation of an industrial process".[433]

Furthermore, the Hydrogen Ordinance defines three different types of hydrogen: renewable, low-carbon and fossil:

- renewable hydrogen is hydrogen which is produced by electrolysis using electricity from a renewable energy source and where the associated CO_2 emissions are below a certain threshold;[434]
- low-carbon hydrogen is hydrogen where the production process fewer or equal emissions to the threshold;[435]
- fossil hydrogen is hydrogen that is neither renewable nor low carbon.[436]

Support mechanism for renewable hydrogen or low-carbon hydrogen from water electrolysis

The Hydrogen Ordinance also provides for a support mechanism to assist the development of renewable and low-carbon hydrogen produced by electrolysis.[437] This mechanism seeks to support the Government's goal of reaching 20% to 40% renewable/low carbon hydrogen of total consumption of hydrogen and industrial hydrogen by 2030.

It takes the forms of calls for tenders organised by the public authority (ministry of energy and the regulator). Successful bidders will be able to benefit from a contract granting investment financial support (*aide à l'investissement*) and/or a functioning financial support (*aide d'exploitation*). Several selection criterions are set in the ordonnance (eg, level of financial support requested by the bidder, price of the hydrogen, greenhouse gas emissions generated by the hydrogen production).

The duration of the support contract may not exceed 20 years and qualifies as administrative contracts. The holders of support contracts may be subject to controls during the start-up/construction of the plant and during operations.

The sale of hydrogen injected in the natural gas grid will not require a gas supply licence if the hydrogen is sold to an authorised gas supplier. The holder of a gas storage concession will not require a new mining title to store hydrogen when the geological formation to be used was already included in the initial gas storage concession.

The implementing regulations for the Hydrogen Ordinance are still to be published.[438]

Traceability mechanisms

The Hydrogen Ordinance creates two types of guarantees to certify the renewable or low-carbon nature of the hydrogen.

The green tracing guarantee[439] (the "TG") is usable if the renewable or low-carbon hydrogen is not mixed with another type of hydrogen or another gas between the stage of its production and that of its consumption, and the guarantee issued is assigned the same time as the hydrogen produced.

The guarantee of origin[440] (the "GO") is usable if the renewable or low-carbon hydrogen is likely to be mixed with another type of hydrogen or another gas between the stage of its production and that of its consumption or if the guarantee issued during its production is likely to be assigned independently of the hydrogen produced.

The green tracing and guarantees of origin will be managed by an independent body (*organisme de gestion des garanties de production*),[441] which will ensure the issuance, transfer, and cancellation of guarantees.

Guarantees of origin for renewable hydrogen from other Member States of the EU and issued in accordance with the provisions of Directive 2018/001 shall be recognized and treated in the same way as a guarantee of origin linked to a production unit located on French territory.

Injection of hydrogen into the natural gas grid network

The right for renewable and low-carbon hydrogen producers to access the natural gas grid network was introduced by Law no. 2019-1147 dated on Energy and Climate.[442] The Article L. 111-97 of the French Energy Code provides that: "subject to preserving the proper operation and level of safety of natural gas infrastructures, a right of access to natural gas transmission and distribution facilities as well as liquefied natural gas facilities [...] is guaranteed by the operators who operate these infrastructures to customers, renewable gas producers, low-carbon hydrogen producers".

The Hydrogen Ordinance provides a framework for the role of natural gas transmission and distribution system operators (the "TSO"), in the event of the injection of renewable hydrogen into these systems and stipulated that TSOs must ensure the proper functioning and balancing of the systems, the continuity of the natural gas transmission and delivery service and the safety of people and property.[443]

Law no. 2021-1104 dated 22 August 2021, (*portant lutte contre le dérèglement climatique et renforcement de la résilience face à ses effets*. Also called the "Climate and Resilience Law") allows local authorities to participate in the development of hydrogen[444] by developing, operating or delegating the development and operation of hydrogen facilities in the same way as renewable energy projects in accordance with Article L. 2224-32 of the General Code of Local Authorities.

The Minister of Ecological Transition presented on 5 May 2021 a bill ratifying Ordinance no. 2021-167 of 17 February 2021 *relative à l'hydrogène* before the National Assembly.

Remaining obstacles to the development of hydrogen

Despite the publication of a new Hydrogen Ordinance, there remains some legal risk/uncertainty around developing hydrogen generation projects. In a deliberation no. 2020-231 dated 24 September 2020 *portant avis sur le projet d'ordonnance relative à l'hydrogène,*[445] the CRE considered that the existence of two types of guarantees of hydrogen production (TG/GO) is a source of complexity and underlines the residual aspect of TG.

The CRE also pointed out that the French hydrogen market is not yet mature to organise call for tenders and recommended a transitional phase, consisting of the implementation of over-the-counter contracts allowing for specific adaptation to the targeted projects and adjustment of the remuneration to the costs borne by the producers, as well as the development of a more efficient system of payment to the targeted projects could be launched.

Additional regulation is required to regulate the entire hydrogen value chain (production, transport, storage, distribution, end use), regulate integration with the gas and electricity sectors and remove administrative and regulatory obstacles.

H.3 Carbon capture and storage (CCS)

The CCS Directive was transposed into French law in 2010 and 2011. Conditions set out in the Mining Code in respect of mines, mining deposits and exploration permits are applicable to underground formations suitable for geological storage of carbon dioxide and their exploration.

A storage permit granted by the State's local representative is required for the operation of storage sites, and such permits are re-examined periodically. Closure and post-closure obligations, as well as transfer of responsibility provisions, are set in accordance with the CCS Directive, along with rules regarding third party access. CCS facilities are also subject to the regulations relating to the classified facilities for environmental protection purposes (if commissioned before 1 March 2017) or to the granting of a single environmental authorisation (if operated after 1 March 2017).

TotalEnergies tested the first industrial scale CCS chain in Europe at Lacq in the southwest of France and ended the injection of carbon dioxide in March 2013.

H.4 Industrial hubs

N/A

H.5 Smart cities

The smart city is a new concept of urban development. It could be defined as a sustainable city, but also as a connected, intelligent city, capable of understanding the behaviour of its users to optimize and predict its energy consumption. The smart city adapts, reinvents itself, with its inhabitants.

This concept is materialised, among others, by smart grids, smart metring, smart buildings or self-consumption.

Smart grids

Smart grids are an integral part of the smart city, simply because they guarantee optimized energy management within the city.

Smart grids can be defined as an energy network that integrates information and communication technologies, which contributes to improving its operation and developing new uses such as self-consumption, electric vehicles, or storage.

Smart grids make it possible to control energy consumption and optimize it for the consumer. Until recently, the balance of the energy system was mainly obtained by controlling the energy supply (production) according to the demand (consumption), at the best supply and cost conditions. With Smart Grids, it is possible to adapt consumption to production.

Smart metering

Smart metering refers to a device for collecting energy data remotely, via smart meters and sensors.

Associated with a system or an installation (electric, natural gas, hot water...), it allows to:

- remotely monitor energy consumption;
- collect data on consumer usage;
- identify anomalies on the system;
- remotely control the energy flow.

The Energy Code allows gas[446] and electricity[447] transmission and distribution system operators to implement incentives for network users to limit their consumption. For this purpose, Enedis launched the "Linky"[448] meter and GRDF the "Gazpar"[449] meter. The Linky project, as modified by a deliberation of the CRE dated 17 March 2022, has two main objectives for the period 2022-2024: ensure a high level of performance of the communication line and make it easier for the local communities to generate profits.[450]

Smart home

The communicating home is based on the use of home automation and multimedia within the home to create an intelligent digital home network. Innovative electrical technologies and the development of reliable, durable and economical equipment are leading to a wide range of solutions with energy equipment manufacturers.

Housing technologies have the potential to provide users with a very rich range of energy eco-efficiency services, from monitoring consumption, to controlling it, and finally to managing and controlling local production (or even storage).

Today, thanks to advanced meters, the customer can know his electricity consumption and adapt his life habits by having the possibility to directly visualize their consequences on his bill.[451]

Smart buildings

The intelligent building is defined as a highly energy efficient building integrating, in the intelligent management of the building, the consumer equipment, the producer equipment and the possible storage equipment. It is about putting "intelligence" on the private electrical network of buildings (house, apartment building or office building) to facilitate and improve the management of energy and electrical appliances on the network.

Energy efficiency depends largely on building construction techniques, such as insulation. The concept of intelligent building corresponds to the integration of energy management solutions in housing and business buildings, to achieve positive energy buildings. Many solutions exist and are complementary:

- better insulation of buildings: this is the most efficient method to avoid thermal waste and reduces the need for heating outside periods of extreme cold (many materials: glass wool, hemp or straw);
- new energy production techniques: the building allows for the easy integration of energy from renewable sources. The roof can accommodate photovoltaic panels that compensate or even exceed the energy expenses of the inhabitants or solar thermal collectors that heat water for heating or sanitary purposes;
- the development of ventilation systems to avoid losing the benefits of insulation by opening a window in periods of extreme cold or heat (dual flow ventilation or Canadian wells);
- more efficient heating and air conditioning systems (wood stove, heat pump, geothermal energy) and other systems to better regulate the temperature (thermostat, efficient boilers, etc);
- a more thoughtful choice of building location in terms of site and orientation in order to make the most of insulation, openings and photovoltaic panels;
- a systematic measurement of performance, in order to adapt decisions if necessary;
- the development of home automation, more energy-efficient equipment and energy management systems.

Self-consumption

Self-consumption is the fact of consuming on site all or part of the energy produced by an installation. Self-consumption is still a marginal phenomenon on a French scale: according to Enedis, it concerns about 72252 installations and represents only 0.29 GW out of the 8.4 GW of photovoltaic capacities connected to the distribution network at the end of the first quarter 2020.[452] However, it is experiencing a strong dynamic: installations in total or partial self-consumption represented more than three quarters of requests for connection of photovoltaic installations in 2019.

Self-consumption appeared in French law before the release of the Clean Energy Package. Provided for in Article 119 of Law no. 2015-992 dated 17 August 2015 on the energy transition for green growth,[453] Order no. 2016-1019 dated 27 July 2016 on self-consumption of electricity, ratified by the Law no. 2017-227 dated 24 February 24, 2017,[454] enshrined the definition of self-consumption and the related provisions in the Energy Code. These provisions were subsequently amended by Law no. 2019-486 dated 22 May 2019 on business growth and transformation (known as the "PACTE" Law),[455] as well as by Law no. 2019-1147 dated 8 November 2019 on energy and climate.[456]

The Climate and Resilience Law no. 2021-1104 dated 22 August 2021 also includes several provisions in favour of collective self-consumption operations. For example, it extends the obligation provided for in Article L.111-18-1 of the town planning code to install renewable energy production systems or green roofs.[457] Articles L.315-1 to L.315-8 of the Energy Code specify the definitions and the different regimes of self-consumption:

- Article L.315-1 defines an individual self-consumption operation as "the fact that a producer, known as a self-producer, consumes all or part of the electricity produced by his installation. The part of the electricity produced that is consumed is consumed either instantaneously or after a period of storage". This article was amended by Law no. 2019-1147 dated 8 November 2019 on energy and climate, and specifies that "the installation of the self-producer may be owned or managed by a third party. The third party may be entrusted with the installation and management, including maintenance, of the generating facility, so long as the third party remains subject to the self-generator's instructions. The third party itself is not considered a self-producer".
- Article L.315-2 defines a collective self-consumption operation: "the self-consumption operation is collective when the supply of electricity is carried out between one or more producers and one or more final consumers linked together within a legal entity and whose withdrawal and injection points are located in the same building, including residential buildings."

I. Environmental, social and governance (ESG)

Definition[458]

Corporate Social Responsibility (CSR) and Environment, Social and Governance (ESG) criteria are closely related concepts. CSR can be defined as the contribution of companies to sustainable development goals. A company that practices CSR seeks to have a positive impact on society while being economically viable. ISO 26000, an international standard, defines the scope of CSR around 7 central topics:

- governance;
- human rights;
- work relations and working conditions;
- environment;
- ethical business practices;
- consumer related issues; and
- communities and local development.

ESG criteria consist in a set of extra-financial analysis criteria (environmental, social and governance) which makes possible to evaluate the consideration given to sustainable development and long-term issues in the company's strategy.

In other words, ESG analysis is the measurement by an investor of a company's CSR performance.

A binding legal framework for companies[459]

The legal framework on environmental issues

- Against the background of the global growth and emphasis on ESG regulatory frameworks, it is critical that companies in the energy sector adapt to an increasingly dynamic and stringent regulatory framework on environmental issues. New requirements for ESG monitoring and compliance will have aa significant impact on companies' activities because they must adapt their global strategy to achieve the objectives set by the various laws and regulations in force. Generally, companies that fail to adapt to the ESG landscape, are at risk of falling behind in competitiveness, loosing investors, suffering reputational damage and are exposed to risks in their supply chains and long-term strategy.

- In France, recent legal evolutions incite companies to define low-carbon strategies and to improve their energy performance. For example, several texts create an incentive for companies to reduce their greenhouse gas (GHG) emissions by creating, for example, a tax on GHG emissions, which is the purpose of the Climate-Energy Contribution implemented in 2014 as part of Law no. 2013-1278 Finance Act for 2014.[460]
- In 2019, two major texts entered the panorama of legislations promoting renewable energies and energy efficiency in buildings, namely Law no. 2019-1147 of 8 November 2019 on Energy and Climate and Decree no. 2019-771 of 23 July 2019 related to the actions to be taken to reduce final energy consumption (*dans les bâtiments du secteur tertiaire*) (also called "*Décret tertiaire*"). The new thermal regulation (called "RE2020") introduced by Law no. 2018-1021 of 23 November 2018 on the evolution of housing, planning and the digital (ELAN law),[461] also sets new targets to reduce the energy consumption of buildings.
- In addition to this, since the enactment of Order no. 2017-1180 of 19 July 2017 and Decree no. 2017-1265 of 9 August 2017 transposing the directive 2014/95/EU on the publication of non-financial information, companies must declare their extra-financial performance, which concerns, among other things, information related to the consequences on climate change of the company's activity, Other corporate disclosure requirements under the aforementioned Orders/Decrees include disclosures on sustainable development, anti-discrimination and the promotion of diversity.
- Furthermore, reporting obligations have been reinforced by the recent adopted Climate and Resilience Law. Notably, the Climate and Resilience Law requires that the extra-financial performance statement must include new information on the consequences of the company's activity on climate change. This information includes in particular:
- direct and indirect GHG emissions linked to transport activities upstream and downstream of the activity,
- this information will be completed by an action plan aimed at reducing these emissions, in particular through the use of rail and waterway modes as well as biofuels with a virtuous energy and carbon balance and electromobility,
- these obligations are applicable to financial years beginning on or after 1 July 2022: it concerns the extra-financial performance declaration presented to the general meetings to be held in 2024 for companies closing their books on 31 December 2023.[462]
- Finally, the law is also evolving towards the introduction of new sanctions for environmental damages (*préjudice environnemental*). The Climate Resilience Law creates three environmental offences namely, (i) the offence of ecocide; (ii) the offence of endangering the environment; and (iii) the offence of air and water pollution.
- This more restrictive legal framework also increases the risk for companies to be held liable before national courts for failure to meet their environmental obligations, but also the French State as drawn by the "*Affaire du Siècle*" caselaw, for example.

The legal framework on governance with the French duty of care[463]

Law no. 2017-399 of 27 March 2017 on the duty of vigilance of parent companies and instructing undertakings, institutes a duty of care for some companies in order to prevent risks and serious violations of human rights (freedoms, health and safety) and against the environment, resulting from the activities of the company and controlled companies within the accounting meaning of the term and of its subcontractors or suppliers. This duty of care applies to joint-stock companies and partnership limited by shares (*société en commandite par actions*) that exceed the following thresholds over two successive financial years:

- 5,000 employees in their direct and indirect French subsidiaries; and
- 10,000 employees within them and in their direct and indirect French and foreign subsidiaries.

The duty of care involves an obligation for the companies concerned to publish a vigilance plan. This plan must include:[464]

- a mapping of risks;
- a procedure for regular assessment of the situation of subsidiaries, subcontractors or suppliers;
- appropriate actions to mitigate risks or prevent serious harm;
- an alert and reporting mechanism established in consultation with the unions; and
- a system for monitoring the measures implemented.

The plan and the report on its implementation must be made available to the public and included in the company's management report.

In addition, the law provides for two legal actions aiming at sanctioning companies for non-compliance to their obligations related to the duty of care:

- any person with an interest to act, may three months after an unfruitful formal notice, refer the matter to the judge so that he orders the company to comply with its obligation to adopt and publish a vigilance plan and to publish the report on its effective implementation;[465] and
- any person who has suffered damage because of a company's failure to fulfil its obligations may seek compensation.[466]

Therefore, failure to comply with this obligation to disclose exposes the company to several sanctions, namely:

- a formal notice (3 months) and injunction from the judge (on the merits or in summary proceedings);
- the civil liability of its author under ordinary law; and
- an accessory sentence: publication of the judicial decision at the company's expense.

Therefore, this law presents a reputational risk for companies with regard to the mechanisms it provides for holding them liable for failure to fulfil their obligations under the duty of care.

Lawsuits initiated based on the duty of care

Following the publication of the first due diligence plans in 2018, several companies were summoned by Non-Governmental Organizations (NGOs) for failing to meet their obligations under the duty of care. For example, in the case of Total, which was summoned to court on 28 January 2020 by fourteen local authorities and NGOs, who asked the judge to order the company to take the necessary measures to drastically reduce its greenhouse gas emissions. The case is still pending before the court.[467]

A second example is EDF and its subsidiary EDF Renewables case that were taken to court by NGOs on 13 October 2020. NGOs accused the group (EDF Renewables) and its subsidiary of failure to conduct consultations with the indigenous populations for the construction of a wind farm in Mexico composed of 115 turbines with a capacity of 300MW.

Investors increasingly pay attention to ESG issues

Given the practical impact of new regulations setting ever more ambitious CSR objectives, investors are now paying an increasing attention to the inclusion of environmental, social and governance criteria in the projects carried out by companies and this for several reasons related to:[468]

- the impact on the long-term performance of the company;
- the influence on the company's brand image and reputation;
- a major issue of reducing the investment risk for investors;
- regulatory/publication requirements both for companies and investors; and
- external stakeholder requirements.

Investors use different methods to guide their choice of funding a project while keeping in mind ESG dimensions, as for example:[469]

- the integration approach: aware of the influence of ESG issues on the financial performance of companies, investors take them into account in their investment analysis; and
- the screening approach: the investor uses filters to exclude certain sectors, companies or practices, for example by referring to the company's environmental rating (eg, GHG emissions).

Moreover, French extra-financial rating agencies, such as Vigeo, Ethifinance, Innovest and BMJ CoreRating, help investors better identify the risks related to ESG issues. Thus, a certain number of investors refer to the extra-financial rating produced by these agencies in terms of environmental, social and governance issues to make better investment choices.

Investors as responsible investment agents

Additionally, investors are themselves becoming players in the transition of the economy towards greater consideration of CSR issues, particularly through the development of green financing through instruments such as:[470]

- impact loans;
- green bonds and social bonds; and
- sustainability linked bonds.

This new financing creates a strong economic incentive for companies to respect CSR objectives and for investors to fund environmentally or socially responsible projects.

Today, France plays a leading role in the green bond market. Since 2012, the country has accumulated nearly €50 billion in green bonds. In 2017, France launched its first green sovereign bond, becoming the first country in the world to issue a large-scale green bond. This initiative has been highly successful among investors.[471]

Many of the projects funded are related to the energy transition tax, environmental research, space technology for earth observation, waterway maintenance and forest management.

The dynamic should continue as on 5 January 2022, RTE announced the launch of its first green bond with a total of €850 million raised. It will be dedicated to the financing and refinancing of several sustainable development projects, the connection of offshore wind farms and electrical interconnections with neighbouring European countries.[472]

Endnotes

1. Law No. 2000-108 of 10 February 2000 *relative à la modernisation et au développement du service public de l'électricité*.
2. Law No. 2003-8 of 3 January 2003 *relative aux marchés du gaz et de l'électricité et au service public de l'énergie*.
3. Law No. 2004-803 of 9 August 2004 *relative au service public de l'électricité et du gaz et aux entreprises électriques et gazières*.
4. Law No. 2006-1537 of 7 December 2006 *relative au secteur de l'énergie*.
5. Law No. 2010-1488 of 7 December 2010 *portant nouvelle organisation du marché de l'électricité*.
6. Ordonnance No. 2011-504 of 9 May 2011 *portant codification de la partie législative du code de l'énergie*.
7. Law No. 2013-312 of 15 April 2013 *visant à préparer la transition vers un système énergétique sobre et portant diverses dispositions sur la tarification de l'eau et sur les éoliennes*.
8. Regulation 2011/1227; OJ L 326 of 08.12.2011, p. 1.
9. The main innovation of the adopted bill was the implementation of a bonus/penalty system regarding the energy consuming behaviour of each household, but was cancelled by the Constitutional Council (*Conseil Constitutionnel*) (Decision n°2013-666 DC of 11 April 2013).
10. Decree No. 2015-1823 of 30 December 2015 *relatif à la codification de la partie réglementaire du code de l'énergie*.
11. Law No. 2015-992 of 17 August 2015 *relative à la transition énergétique pour la croissance verte*.
12. Please confer the follow-up table of implementing decrees on the legifrance website: www.legifrance.gouv.fr/affichLoiPubliee.do;jsessionid=F0C359868740958E0D727408FC9371AA.tpdila09v_2?idDocument=JORFDOLE000029310724&type=echeancier&typeLoi=&legislature=14
13. Article L. 100-4 of the Energy Code.
14. Article L. 141-1 of the Energy Code.
15. Articles L. 100-1, L. 100-2,L. 100- 4of the Energy Code
16. Decree No. 2016-1442 dated 27 October 2016 *relatif à la programmation pluriannuelle de l'énergie*.
17. Article L. 141-4 of the Energy Code.
18. Decree No. 2015-1697 dated 18 December 2015 *relatif à la programmation pluriannuelle de l'énergie de Corse*.
19. Decree No. 2017-577 dated 19 April 2017 *relatif à la programmation pluriannuelle de l'énergie de Mayotte*.
20. Decree No. 2017-570 dated 19 April 2017 *relatif à la programmation pluriannuelle de l'énergie de la Guadeloupe*.
21. Decree No. 2017-457 dated 30 March 2017 *relatif à la programmation pluriannuelle de l'énergie de la Guyane*.
22. Decree No. 2017-530 dated 12 April 2017 *relatif à la programmation pluriannuelle de l'énergie de La Réunion*.
23. See www.ecologique-solidaire.gouv.fr/sites/default/files/Projet%20PPE%20pour%20consultation.pdf
24. Law No. 2004-803 and its implementing decree No. 2004-1224 of 17 November 2004 *portant statuts de la société anonyme Electricité de France*.
25. Article L. 111-67 of the Energy Code.
26. See www.edf.fr/groupe-edf/espaces-dedies/finance/informations-financieres/l-action-edf/structure-du-capital
27. The representative may: (i) attend board meetings of the board of directors and its committees in an advisory capacity; (ii) present observations at any shareholders' meetings; and (iii) in some companies, block transactions deemed contrary to public interest.
28. Any company producing more than 33 per cent of national electricity production (Art L 311-5-7 of the Energy Code introduced by the Energy Transition Law), ENGIE (Art L. 111-70 of the Energy Code), EDF (Decree No. 2004-1224 dated 17 November 2004), Compagnie nationale du Rhône (Law No. 80-3 dated 4 January 1980) and some pipeline management companies.
29. 2021 Annual Electricity Report by RTE www.bilan-electrique-2021.rte-france.com/synthese-les-faits-marquants-de-2021
30. 2021 Annual Electricity Report by RTE (*Bilan électrique* 2021).
31. See www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-fr/informations-financieres/publications-financieres/faits-et-chiffres/facts-and-figures-2017-fr.pdf see page 29
32. EDF 2017 reference document, section 1.4.1 (at 31 December 2017). Please see the link above.
33. See www.engie.fr/electricite
34. Article R. 311-8 of the Energy Code.
35. Articles L. 311-1 *et seq*. and article R. 311-2 of the Energy Code as amended by decree No. 2016-687 of 27 May 2016 *relatif à l'autorisation d'exploiter les installations de production d'électricité*. The 50MW threshold applies to the facilities using the following types of energy sources: solar energy; wind energy; combustion or explosion of non-fossil fuel (animal or vegetal); combustion or explosion of biogas; geothermal energy and waste reclamation.
36. Article L. 511-1 and L. 511-5 of the Energy Code.
37. Article L. 521-1 of the Energy Code and Ordinance No. 2016-65 dated 29 January 2016.
38. Article R. 521-8 of the Energy Code.
39. Article R. 521-67 et seq. of the Energy Code
40. Articles L. 521-16-1 and L. 521-16-2 of the Energy Code
41. Article L. 521-16-3 of the Energy Code
42. Articles L. 111-40, L. 321-1 and L. 321-2 of the Energy Code. The concession was entered into on 27 November 1958, amended on 30 October 2008 and its term expires on 31 December 2051.
43. Decree No. 2006-1731 of 23 December 2006 approving the standard conditions for the concession of the public transmission network.
44. Article 7 of Law No. 2004-803.
45. See www.caissedesdepots.fr/en/rte-edf-caisse-des-depots-and-cnp-assurances-sign-binding-agreement-long-term-partnership-1.
46. EDF 2017 reference document, section 1.4.4.2. www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-finance-en/financial-information/regulated-information/reference-document/edf-ddr-2017-en.pdf
47. Please refer to the articles L. 111-2 to L. 111-66 of the Energy Code.
48. Articles L. 111-3 *et seq*. and R. 111-1 *et seq*. of the Energy Code.
49. CRE Deliberation dated 26 January 2012 *portant décision de certification de la société RTE* ; CRE Deliberation 2018-005 dated 11 January 2018 *portant décision sur le maintien de la certification de la société RTE*.
50. Opinion of the European Commission dated 25 November 2011 – C(2011) 8570 final and opinion of the European Commission dated 10 January 2018 – C(2018) 150 final
51. Article L. 111-5 of the Energy Code.
52. Article L. 111-5 of the Energy Code.
53. Article L. 111-6 of the Energy Code.
54. EDF 2017 reference document, section 1.4.2.1.2.
55. CRE, Electricity and gas market observatory, 3rd quarter of 2018. See file:///C:/Users/RB14895/Downloads/Observatoire_detail_T3_2018.pdf
56. Article L. 333-1 of the Energy Code.

57. R. 333-1 of the Energy Code.
58. L. 333-1 and R. 333-1 of the Energy Code.
59. Article 8 of decree No. 2016-1570 dated 22 November 2016 *relatif à l'autorisation d'exercer l'activité d'achat d'électricité pour revente*.
60. Article L. 333-2 of the Energy Code. See the list published on the Ministry for Ecology's website: www.ecologique-solidaire.gouv.fr/sites/default/files/Liste%20des%20fournisseurs%20d%27%C3%A9lectricit%C3%A9%20autoris%C3%A9s.pdf
61. L. 337-4 of the Energy Code.
62. R. 337-18 *et seq.* of the Energy Code in accordance with the Decision dated 31 January 2018
63. The TaRTAM system allowed end customers having opted for the free market tariff to revert to a regulated price, under certain conditions.
64. Decision of the European Commission dated 12 June 2012, No. SA.21918, C(2012)2559 final.
65. Article L. 337-9 of the Energy Code.
66. *Ordonnance* No. 2016-129 dated 10 February 2016 *portant sur un dispositif de continuité de fourniture succédant à la fin des offres de marché transitoires de gaz et d'électricité*.
67. CRE deliberation of 4 May 2016 *portant décision de désignation de fournisseurs assurant la continuité de fourniture à la fin des offres de marché transitoires de gaz et d'électricité*.
68. CRE deliberation of 14 December 2016 *portant décision de désignation de fournisseurs assurant la continuité de fourniture à la fin des offres de marché transitoires de gaz et d'électricité*.
69. Article L. 337-8 of the Energy Code.
70. Article R. 337-18 of the Energy code
71. CE, 7 December 2016, *ANODE*, No. 393729; CE, 15 June 2016, *ANODE*, No. 381255; CE, 15 June 2016, *ANODE*, No. 386078; CE,15 June 2016, *ANODE*, No. 383722; CE, 18 May 2016, *Société Direct Energie*, No. 386810; CE, ord. 7 January 2015, *ANODE*, No. 386076; CE, ord. 12 September 2014, *ANODE*, No. 383721; CE, 11 April 2014, *ANODE*, No. 365219.
72. Conseil d'État, 18 May 2018, *Société Engie et Association nationale des opérateurs détaillants en énergie* or *ANODE*, No. 413688, 414656.
73. CRE decision no. 2018-157 dated 12 July 2018 *portant proposition des tarifs réglementés de vente d'électricité*
74. Ministerial order dated 27 July 2018 *relatif aux tarifs réglementés de vente de l'électricité applicables aux consommateurs non résidentiels en France métropolitaine continentale*
75. Decree No 2008-1354 of 18 December 2008
76. Articles 3 and 4 of the decree 2014-1250 of 28 October 2014 *modifiant le décret n° 2009-975 du 12 août 2009 relatif aux tarifs réglementés de vente de l'électricité.*
77. Art L. 336-1 *et seq.* of the Energy Code.
78. An adjustment mechanism consisting of an additional price is provided for by the law in case the volume bought by a supplier under the ARENH mechanism exceeds the volume of electricity supplied to its clients in France.
79. Article L. 336-2 of the Energy Code.
80. Article L. 336-2 of the Energy Code.
81. Article L. 336-2 of the Energy Code and ministerial order dated 28 April 2011 *fixant le volume global maximal d'électricité devant être cédé par Electricité de France au titre de l'accès régulé à l'électricité nucléaire historique*
82. Ministerial order dated 17 May 2011 *fixant le prix de l'accès régulé à l'électricité nucléaire historique à compter du 1er janvier 2012*.
83. Articles L. 337-13 and L. 337-16 of the Energy Code.
84. See www.proxy-pubminefi.diffusion.finances.gouv.fr/pub/document/18/16115.pdf./www.autoritedelaconcurrence.fr/doc/rapport_arenh.pdf
85. See www.cre.fr/Electricite/Marche-de-gros-de-l-electricite/Acces-regule-a-l-electricite-nucleaire-historique
86. CRE, Press release dated 29th November 2018, available on www.cre.fr/Actualites/Les-demandes-d-ARENH-pour-2019
87. Article L. 336-3 of the Energy Code.
88. Article L. 336-3 of the Energy Code.
89. Decree No. 2011-466 of 28 April 2011 *fixant les modalités d'accès régulé à l'électricité nucléaire historique* and articles R. 336-1 *et seq.* of the Energy Code.
90. Article R. 336-2 of the Energy Code.
91. Article L. 336-5 of the Energy Code.
92. Ministerial order of 28 April 2011 *pris en application du II de l'article 4-1 de la loi n° 2000-108 relative à la modernisation et au développement du service public de l'électricité.*
93. Ministerial order of 14 November 2016 *portant modification de l'arrêté du 28 avril 2011 pris en application du II de l'article 4-1 de la loi n° 2000-108 relative à la modernisation et au développement du service public de l'électricité* and Ministerial order of 12 March 2019 *portant modification de l'arrêté du 28 avril 2011 pris en application du II de l'article 4-1 de la loi n° 2000-108 relative à la modernisation et au développement du service public de l'électricité*.
94. As of 31 October 2018, 82 suppliers had entered into framework agreements with EDF, see www.cre.fr/Electricite/Marche-de-gros-de-l-electricite/Acces-regule-a-l-electricite-nucleaire-historique
95. Articles L. 134-1 *et seq.* of the Energy Code.
96. Article L. 111-93 of the Energy Code.
97. Article L. 342-4 of the Energy Code.
98. Articles L. 111-84 *et seq.* of the Energy Code provides that a vertically integrated undertaking must have an accounting separation between the diverse activities carried out.
99. Article L. 134-19 of the Energy Code.
100. Ministerial Order of 9 June 2020 *relatif aux prescriptions techniques de conception et de fonctionnement pour le raccordement aux réseaux d'électricité*, article 24 and RTE technical documentation, chapter 1, article 1.2, paragraph 4.2, p.5.
101. Article L. 111-91 of the Energy Code.
102. Article L. 111-93 of the Energy Code.
103. Article L. 342-3 of the Energy Code.
104. Report of Mrs. Serge Poignant, *député* of Loire-Atlantique and Bruno Sido, *sénateur* of Haute-Marne, called *Groupe de travail sur la Maîtrise de la pointe électrique* and filed with the Minister for Ecology on April 2010. (lien)
105. Articles L. 335-1 and seq. of the Energy Code. Articles L. 335-2 and L 335-3 have been amended by the order No 2021-237 of 3 March 2021 transposing Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 concerning common rules for the internal market in electricity (lien)
106. Article 15 of the law No. 2013-312 of 15 April 2013, now codified in article L. 335-1 of the Energy Code. (lien); (lien)
107. Article L. 335-5 of the Energy Code.(lien)
108. Article 149 of the Energy Transition Law, now codified in article L. 335-5 of the Energy Code.(lien) ; (lien)
109. Article R. 335-1 *et seq.* of the Energy Code confirmed by CRE decision dated 24 November 2016.(lien)
110. Article L. 335-3 of the Energy Code.(lien) amended by the order No 2021-237 of 3 March 2021 transposing Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019

111. Article L.335-7 of the Energy Code. (lien)

112. French Competion Authority, opinion No. 12-A-09 dated 12 April 2012 (lien)

113. Decree No. 2012-1405 of 14 December 2012 as amended by Decree n° 2018-997 of 15 November 2018 *relatif au mécanisme d'obligation de capacité dans le secteur de l'électricité* (lien) ; (lien)

114. Please refer to articles R.335-1 to R.335-54 as amended by Decree n° 2018-997 of 15 November 2018 relatif au mécanisme d'obligation de capacité dans le secteur de l'électricité

115. Deliberation of CRE of 28 May 2014 on the capacity mechanism rules provided by the decree No. 2012-1405. (lien)

116. Ministerial order of 22 January 2015, NOR: DEVR1418335A (lien)

117. CE, 9 October 2015, *ANODE*, No. 369417.(lien)

118. Case No. C-543/15. (lien)

119. CE, 16 March 2016, *ANODE*, No. 369417. (lien)

120. ECJ, ord., 12 April 2016, *ANODE*, No. C-543/15.

121. CE, 13 May 2016, *Société Voltalis*, No. 375120. (lien)

122. European Commission, 13 November 2015, C/7805/2015.

123. Deliberation of CRE of 24 November 2016 on the draft rules of capacity mechanism. (lien)

124. Ministerial order of 29 November 2016, NOR:DEVR1632005A. (lien)

125. See www.europa.eu/rapid/press-release_IP-16-3620_fr.htm (lien)

126. Decree no. 2018-997 dated 15 November 2018 relatif au mécanisme d'obligation de capacité dans le secteur de l'électricité (lien)

127. Ministerial order dated 21 December 2018 définissant les règles du mécanisme de capacité et pris en application de l'article R. 335-2 du code de l'énergie (lien)

128. Deliberation of CRE of 28 November 2019 on the draft of rules of the capacity mechanism (lien)

129. Deliberation of CRE of 10 September 2020 on the project to modify the rules of the capacity mechanism proposed by RTE to contribute to the security of supply for the winter of 2020-2021 (lien)

130. Updated vision as at 18.09.2020 covering the 2020 and 2021 delivery years (lien)

131. Available on www.eqinov.com/blog/encheres-de-capacite-les-resultats-de-de-decembre-2018/ (lien)

132. Available on www.eqinov.com/blog/encheres-de-capacite-les-resultats-de-mars-2019/ (lien)

133. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-de-mars-2021

134. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-avril-2021

135. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-de-juin-2021

136. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-de-septembre-2021

137. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-de-octobre-2021

138. Results of the latest auctions on the capacity mechanism www.eqinov.com/eqilibreblogenergie/encheres-de-capacite-les-resultats-de-decembre-2021

139. Deliberation of CRE dated 9 July 2009 *portant communication sur l'intégration des effacements diffuse au sein du mécanisme d'ajustement* (lien)

140. CE, 3 May 2011, *Voltalis*, No. 331858. (lien)

141. Please refer to article 14 of the law No. 2013-312 of 15 April 2013 (codified into Article L. 271-1 and seq. of the Energy Code).(lien) (lien)

142. Deliberation of CRE dated 28 November 2013. (lien)

143. Deliberation of CRE dated 7 May 2014.

144. CE, ref., 28 July 2014, *Voltalis*, No. 381731 (lien); CE, 15 February 2016, *Voltalis*, No. 381730.

145. Deliberation of CRE dated 17 December 2014.(lien)

146. CE, 13 May 2016, Voltalis, No. 388101.(lien)

147. Please refer to article R. 271-4 of the Energy Code.(lien)

148. Please refer to articles R. 271-5 to R. 271-7 of the Energy Code.(lien)

149. Please refer to article L. 271-4 of the Energy Code.(lien) amended by article 14 of the Order No 2021-237 of 3 March 2021 transposing Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 concerning common rules for the internal market in electricity

150. Publication by the RTE of on call of tenders regarding 2022 (lien)

151. Publication by RTE on the launch of the 2022 call for tenders (lien)

152. Please refer to articles L. 321-10 (lien) *et seq.* of the Energy Code. Article L321-11 of the Energy Code has been amended by the order No 2021-237 of 3 March 2021 transposing Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 concerning common rules for the internal market in electricity;

153. Please refer to article L. 121-8-1 of the Energy Code (lien). Rules on new balancing mechanisms have recently been approved in a CRE decision on 10 March 2016.

154. French competition authority, opinion No. 13-A-25 dated 20 December 2013. (lien)

155. Decree No. 2014-764 dated 3 July 2014 *relatif aux effacements de consommation d'électricité* (now codified at Article R. 271-1 *et seq.* of the Energy Code). (lien)

156. Ministerial order dated 11 January 2015 *fixant le montant de la prime versée aux opérateurs d'effacement* (lien)

157. CE, 16 March 2016, *UFC Que Choisir*, No. 388762. (lien)

158. Article L. 341-1 *et seq.* of the Energy Code

159. Article L. 341-4-2 of the Energy Code as amended by Law No.2016-1888 dated 28 December 2016, decree No. 2016-141 dated 11 February 2016 *relatif au statut d'électro-intensif et à la réduction de tarif d'utilisation du réseau public de transport accordée aux sites fortement consommateurs d'électricité* and decree No. 2017-308 dated 9 March 2017 *modifiant les dispositions relatives au statut d'électro-intensif et à la réduction de tarif d'utilisation du réseau public de transport accordée aux sites fortement consommateurs d'électricité*.

160. Deliberation of CRE dated 17 November 2016 *portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans le domaine de tension HTB* and *portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans les domaines de tension HTA et BT.*

161. CRE Deliberation dated 28 June 2018 portant décision sur les tarifs d'utilisation des réseaux publics d'électricité dans les domaines de tension HTA et BT

162. Please refer to www.inis.iaea.org/collection/NCLCollectionStore/_Public/37/077/37077295.pdf (last referenced on 10 October 2012)

163. Law no. 2015-1786 of 29 December 2015, *Amending Finance Law for 2015 as amended by Law no. 2017-1837 of 30 December 2017*

164. Decree no. 2016-158 of 18 February 2016 *relatif à la compensation des charges de service public de l'énergie*

165. Article 201, Law no. 2015-992 of 17 August 2015 *relative à la Transition Énergétique pour la Croissance Verte*

166. Please refer to articles L. 124-1 *et seq.*, and R. 124-1 to R. 124-16 of the Energy Code

167. Order of the 24 February 2021 *modifiant le seuil d'éligibilité du chèque énergie et instituant un plafond aux frais de gestion pouvant être déduits de l'aide spécifique*

168. Article L. 341-4 of the Energy Code

169. Articles R. 341-4 *et seq.* of the Energy Code

170. Please refer to www.cre.fr/documents/deliberations/communication/resultats-de-l-experimentation-linky

171. See www.smartgrids-cre.fr/index.php?p=compteurs-generalisation-linky

172. See www.smartgrids-cre.fr/index.php?p=compteurs-regulation_incitative

173. CRE decision of 17 July 2014 *portant décision sur le cadre de régulation incitative du système de comptage évolué d'ERDF dans le domaine de tension BT ≤ 36kVA*

174. Decree no. 2015-1823 of 30 December 2015 *relatif à la codification de la partie réglementaire du code de l'énergie*.

175. *Conseil d'État*, decision of 20 March 2013, no. 354321

176. See for example the ordinnance no. 1603910 of 1 June 2016 of the Nantes administrative tribunal, the ordinnance no. 1604068 of 14 October 2016 of the Bordeaux administrative court and the ordinnance no. 1803737 of 10 September 2018 of the Toulouse administrative court

177. See Conseil d'État, decision of 11 July 2019, no. 426060

178. See the judgement of the Versailles administrative court of 21 July 2021, no. 19VE03905 and of the Paris administrative court of 4 June 2021, no. 20PA01495.

179. See www.enedis.fr/le-compteur-linky-bientot-chez-vous

180. Article 41 of the Energy Transition Law

181. See www.ecologie.gouv.fr/sites/default/files/20200422%20Programmation%20pluriannuelle%20de%20l%27e%CC%81nergie.pdf

182. *Plan Climat* of 6 July 2017 p. 6 (www.ecologique-solidaire.gouv.fr/sites/default/files/2017.07.06%20-%20Plan%20Climat_0.pdf

183. Article 37 of the Energy Transition Law, Articles L. 224-7 and L. 224-8 of the French Environment Code and Decrees no. 2017-21, no. 2017-22, no. 2017-23 and no. 2017-24 of 11 January 2017

184. Annex to the *Projet de loi de finances 2019* (report on the implementation of the *Investissements d'Avenir* program) (www.performance-publique.budget.gouv.fr/sites/performance_publique/files/files/documents/jaunes-2019/Jaune2019_investissements_avenir.pdf

185. Article 200 quater i) of the French Tax Code and Article 57 of the Draft Finances Law for 2019

186. Decree no. 2021-546 of 4 May 2021 *portant modification du décret n° 2017-26 du 12 janvier 2017 relatif aux infrastructures de recharge pour véhicules électriques et portant diverses mesures de transposition de la directive 2014/94/UE du Parlement européen et du Conseil du 22 octobre 2014 sur le déploiement d'une infrastructure pour carburants alternatif.*

187. Decree no. 2021-565 of 10 May 2021 *relatif aux schémas directeurs de développement des infrastructures de recharges ouvertes au public pour les véhicules électriques et les véhicules hybrides rechargeables*

188. Article 118 of the Law no. 2021-1104 of 22 August 2021 *portant lutte contre le dérèglement climatique et renforcement de la résilience face à ses effets (1)*

189. Order no. 2021-237 of 3 March 2021 *portant transposition de la directive (UE) 2019/944 du Parlement européen et du Conseil du 5 juin 2019 concernant des règles communes pour le marché intérieur de l'électricité et modifiant la directive 2012/27/UE, et mesures d'adaptation au règlement (UE) 2019/943 du Parlement européen et du Conseil du 5 juin 2019 sur le marché intérieur de l'électricité*

190. See www.ecologie.gouv.fr/deploiement-des-bornes-recharge-electrique-moitie-des-aires-service-desormais-equipees

191. Law no. 2019-1428 of 24 December 2019 *d'orientation des mobilités*

192. Article 64 of the Law no. 2019-1428 of 24 December 2019 *d'orientation des mobilités* ; and Order of 27 April 2021 *modifiant l'arrêté du 12 mai 2020 relatif à la prise en charge par le tarif d'utilisation des réseaux publics d'électricité du raccordement aux réseaux publics d'électricité des infrastructures de recharge de véhicules électriques et hybrides rechargeables ouvertes au public et des ateliers de charge des véhicules électriques ou hybrides rechargeables affectés à des services de transport public routier de personnes*

193. Article L.113-11 *et seq.* of the Code on Construction and Housing

194. Article L.113-13 of the Code on Construction and Housing

195. Decree no. 2021-153 of 12 February 2021 *instaurant une aide en faveur des investissements relatifs aux installations de recharge rapide pour véhicules électriques sur les grands axes routiers* and Order of 15 février 2021 *relatif aux modalités de gestion de l'aide en faveur des investissements relatifs aux installations de recharge rapide pour véhicules électriques sur les grands axes routiers*.

196. Decree no. 2022-945 of 28 June 2022 *relatif aux infrastructures de recharge de véhicule électrique (IRVE) en copropriété*

197. Decree no. 2022-959 of 20 June 2022 *relatif aux conventions sans frais entre les opérateurs d'infrastructures de recharge pour véhicules électriques et les propriétaires ou les syndicats des copropriétaires pour l'installation d'une infrastructure collective dans l'immeuble*

198. Articles L. 121-4 and L. 321-6 of the Energy Code.

199. CRE deliberation of 29 March 2012 *portant communication sur l'application de l'article 17 du règlement (CE) n° 714/2009 du 13 juillet 2009.*

200. Decision no. 2021-175 of the CRE of 17 June 2021 *portant décision d'approbation du modèle de convention de raccordement d'une interconnexion exemptée en courant continu au réseau public de transport d'électricité* and Decision No. 2021-176 of the CRE of 17 June 2021 *portant décision d'approbation de la procédure de traitement des demandes de raccordement des interconnexions exemptées au réseau public de transport d'électricité*

201. Decision no. 2022-85 of 17 March 2022 *portant approbation du modèle de contrat d'accès au réseau public de transport d'électricité définitif pour les nouvelles interconnexions dérogatoires*.

202. See www.ec.europa.eu/atwork/applying-eu-law/infringements-proceedings/infringement_decisions/index.cfm?lang_code=EN&r_dossier=&noncom=0&decision_date_from=&decision_date_to=&active_only=0&DG=TAXU&title=&submit=Search, infringement number 20142269

203. Art. R335-24 and following of the Energy Code

204. Please refer to Access Rules for Imports and Exports on the French Public Power Transmission System for the year 2018 available on www.clients.rte-france.com/htm/fr/offre/telecharge/Regles_IE_V3.8_Fr.pdf

205. 2020 Annual Electricity Report by RTE available on www.bilan-electrique-2020.rte-france.com/prix-echanges-solde-france-echanges/#:~:text=Le%20solde%20fran%C3%A7ais%20des%20%C3%A9changes,6%20TWh%20(%2B22%20%25).

206. Law No. 2004-803 dated 9 August 2004.

207. Decree No. 2007-1784 dated 19 December 2007.

208. On August 2022

209. Article L. 111-70 of the Energy Code.

210. Total, press release dated 27 March 2015, Lacq an exemplary industrial reconversion.

211. See www.connaissancedesenergies.org/le-gaz-consomme-en-france-vient-principalement-de-russie-120222#notes

212. TIGF, annual activity report 2015, p. 9.

213. Under the conditions provided for by law no 2001-1276 of 28 December 2001, article 81.

214. Articles L. 111-2 to L. 111-66 of the Energy Code.

215. CRE decision of 26 January 2012 *portant décision de certification de la société GRTgaz* and CRE deliberation of 26 January 2012 *portant décision de certification de la société TIGF.* Please refer to: www.cre.fr/documents/deliberations/decision/decisions-de-certification.

216. CRE decision of 3 July 2014 *portant décision de certification de la société TIGF.*

217. CRE decision of 4 February 2016 *portant décision sur le maintien de la certification de la société TIGF à la suite de l'entrée de la société Predica dans le capital de TIGF Holding.*

218. CRE decision of 27 September 2018 *portant décision sur le maintien de la certification de Teréga à la suite d'une prise de participation du groupe GIC dans une entreprise de production d'énergie*

219. Articles L. 555-1 to L. 555-2 of the Environment Code as amended by the Ordonnance n° 2016-282 dated 10 March 2016 *relative à la sécurité des ouvrages de transport et de distribution* and by the Ordonnance n° 2017-80 dated 26 January 2017 *relative à l'autorisation environnementale*.

220. Two exceptions exist however: local gas distribution operators which were already in the public sector in 1946 and have not been nationalised (ELD) (Article L. 111-54 of the Energy Code) and the distribution operators chosen by municipalities which are not supplied with gas (Article L. 432-6 of the Energy Code).

221. Engie, reference document 2015, section 1.3.4.6.3.

222. Articles L. 432-1 *et seq*. of the Energy Code and L. 2224-31 et seq. of the *Code général des collectivités territoriales*.

223. ENGIE, referent document 2017, section 1.1.7.

224. CRE, Electricity and gas market observatory, 4th quarter of 2018.

225. CRE, Electricity and gas market observatory, 4th quarter of 2018.

226. Please note that ministerial orders determine for each supplier the exact applicable tariff.

227. CE, 19 July 2017, ANODE, No. 370321; ECJ, 7 September 2016, *ANODE*, C-121/15; CE, 15 December 2014, *ANODE*, No. 370321; CE, opinion, 16 September 2014, No. 389174; CE, 30 December 2013, *ANODE*, No. 369574; CE, 2 October 2013, *ANODE*, No. 357037.

228. CRE, Electricity and gas market observatory, 4th quarter of 2018.

229. CRE deliberation dated 4 May 2016 *portant décision de désignation de fournisseurs assurant la continuité de fourniture à la fin des offres de marché transitoires de gaz et d'électricité*.

230. CRE deliberation dated 14 December 2016 *portant décision de désignation de fournisseurs assurant la continuité de fourniture à la fin des offres de marché transitoires de gaz et d'électricité*.

231. Articles L. 111-97 *et seq*. of the Energy Code, as amended by the Law n° 2017-1839 dated 30 December 2017.

232. Article L. 111-22 of the Energy Code.

233. Article L. 134-15 of the Energy Code.

234. Ministerial order of 27 May 2005 relating to the definition of balancing zones within the natural gas transportation network as amended by the ministerial order dated 6 October 2008 approving the tariffs for the use of gas transportation networks.

235. ATRT6 have been set up by a CRE deliberation of 15 December 2016. Such tariff apply as of 1 April 2017 for four years.

236. ATRD5 have been set up by a CRE deliberation of 10 March 2016. Such tariff apply as of 1 July 2016 for four years.

237. ATTM5 have been proposed by a CRE deliberation of 8 December 2016. Such tariff apply as of 1 April 2017 for four years.

238. An "entry exit" type tariff is a system in which the TSO markets separately on one hand the entry capacities at each of the entry points of the network and on the other hand the exit capacities at each exit point (or exit zone) of the network.

239. Owned and operated by Elengy, a subsidiary of GDF SUEZ, this terminal is located on the Mediterranean coast and receives LNG primarily from Algeria (GDF SUEZ 2012 reference document, section 1.3.3.7; ENGIE 2017 reference document, section 1.3.7.3.2).

240. Owned and operated by Elengy, a subsidiary of GDF SUEZ, this terminal is located on the Atlantic coast and receives LNG from various sources (GDF SUEZ 2012 reference document, section 1.3.3.7; ENGIE 2017 reference document, section 1.3.7.3.2).

241. Owned by Fosmax LNG in which Elengy holds a 72.5% stake and operated by Elengy, this terminal is located on the Mediterranean coast (GDF SUEZ 2012 reference document, section 1.3.3.7; ENGIE 2017 reference document, section 1.3.7.3.2).

242. See www.edf.fr/sites/default/files/contrib/groupe-edf/espaces-dedies/espace-medias/cp/2017/20170103-mise-en-service-dunkerque-fr.pdf

243. SIG (Société d'Infrastructures Gazières), a company owned by CNP Assurances and the Caisse des Dépôts Group, has sold its stakes in Elengy in exchange for participations in GRTgaz, allowing the latter to become the unique shareholder of Elengy. (see www.engie.com/journalistes/communiques-de-presse/sig-et-engie-annoncent-la-finalisation-de-la-cession-de-11-5-du-capital-de-grtgaz).

244. Elengy purchased Total's shares in Fosmax LNG allowing it to hold 100% of Fos Cavou terminal

245. See www.dunkerquelng.com/1/presentation#actionnaires

246. See www.dunkerquelng.com/1/presentation#actionnaires

247. Article L. 111-97 of the Energy Code, as amended by the Law n°2018-938 dated 30 October 2018..

248. CRE deliberation of 28 May 2003 concerning transparency of available capacity in public gas transmission networks and LNG terminals.

249. This service has been approved as non-regulated by a CRE deliberation of 13 December *2012 portant décision sur le tarif d'utilisation des terminaux méthaniers régulés* (ie, ATTM4).

250. CRE deliberation of 23 May 2013 *portant décision relative à la commercialisation d'un service de transbordement au terminal méthanier de Montoir-de-Bretagne exploité par Elengy*.

251. See www.teekay.com/blog/2015/11/26/teekay-to-start-transshipment-services-at-fos-cavaou-terminal.

252. CRE deliberation of 15 July 2015 *portant décision relative à la commercialisation, à titre expérimental, d'un service de transbordement sur le terminal méthanier de Fos Cavaou de la société Fosmax LNG*.

253. Ministerial order dated 18 February 2010 *autorisant la société Dunkerque LNG à bénéficier d'une exemption à l'accès régulé des tiers pour son projet de terminal méthanier à Dunkerque*. This order was granted following the favourable opinion of CRE, in the deliberation dated 23 July 2009.

254. Commission decision dated 20 January 2010 notified under number C(2010)381, see www.ec.europa.eu/energy/sites/ener/files/documents/2010_dunkerque_decision_fr. pdf.

255. Storengy operates sites representing 76% of French capacity (9 storage facilities being in aquifers and 4 in salt caverns and 1 in depleted deposit), while Téréga operates the remaining 24% (2 storage facilities in aquifers).

256. CE, 15 April 2016, Eni Spa et al., n° 380091, 380336.

257. CJEU, 20 December 2017, Eni SpA, Eni Gas & Power France SA, Uprigaz, C-226/16.

258. Law no. 2017-1839 dated 30 December 2017.

259. Article L. 421-3-1 of the Energy Code.

260. Article L. 452-1 of the Energy Code.

261. Article L. 421-6 of the Energy Code.

262. Article L. 421-7 of the Energy Code.

263. See CRE, public consultation n° 2022-05 «*Relative aux modalités de commercialisation des capacités de stockage de gaz naturel à compter d'octobre 2022*» www.cre.fr/Documents/Publications/Rapports-thematiques/les-prix-a-terme-de-l-electricite-pour-l-hiver-2022-2023-et-l-annee-2023

264. Article L. 443-1 *et seq*. of the Energy Code, as amended by the Ordonnance n° 2018-1165 dated 19 December 2018.

265. Article R. 443-1 *et seq*. of the Energy Code, as amended by the Decree n° 2018-276 dated 18 April 2018.

266. *Article L443-9-1 of the Frenchy energy code introduces by Law No.°2019-1147 dated of 8 November 2019 relative à l'énergie et au climat*

267. Articles L. 121-32 et seq. of the Energy Code.

268. See www.grdf.fr/institutionnel/actualite/newsroom/liste/actualites/signature-du-nouveau-contrat-de-service-public-2019-2023-grdf-renforce-son-r%C3%B4le-dans-la-transition-%C3%A9nerg%C3%A9tique-sur-les-territoires

269. Article L.121-46 of the Energy Code.

270. Article L. 453-7 of the Energy Code.

271. CRE decision of 21 July 2011 *portant proposition d'approbation du lancement de la phase de construction du système de comptage évolué de GrDF.*

272. Decision n° 2014/9/23/DEVR1422501S.

273. www.particuliers.engie.fr/economies-energie/conseils-gazpar/compteur-gaz-communicant-gazpar.html

274. 10-year development plan for the GRTgas transmission network 2018-2027 period.

275. Téréga grid 10-year development plan 2018-2027.

276. 10-year development plan for the GRTGas transmission network 2018-2027, section 4.7 Development of European interconnections.

277. See www.fosmax-lng.com/images/FosmaxLNG_2021-03_OS-FosCavaou_VF_1.pdf

278. The majority of wholesale activity takes place OTC but the exact volume of OTC trading is not made public. (see www.cre.fr/en/Electricity/Wholesale-electricity-market/Wholesale-electricity-market).

279. European Energy Exchange AG holds 51% of the share capital of EPEX Spot SE and HGRT holds the remaining 49% (see www.epexspot.com/en/company-info/about_epex_spot).

280. European Energy Exchange AG holds 100% shares in EEX Power Derivatives GmbH (see www.eex.com/en/about/newsroom/news-detail/eex-ag--power-derivatives-market-transferred-to-independent-company/18078).

281. See www.eex-group.com/en/markets/power-trading

282. See www.powernext.com/fr/fr

283. Fonctionnement_zone_marche_unique_gaz_France

284. See www.acer-remit.eu/ceremp/home?nraShortName=9&lang=fr_FR

285. Articles L. 131-2, L. 134-25 and L. 134-27 of the Energy Code.

286. Article 22 of Brottes Law now codified under articles L. 131-2 and L. 134-25 of the Energy Code.

287. Article 5 of law No. 2006-1537 of 7 December 2006, now codified as article L. 131-2 of the Energy Code.

288. CRE deliberation dated 20 July 2013 *portant décision relative aux informations publiées concernant l'utilisation des terminaux méthaniers.*

289. See www.rte-france.com/actualites/bilan-electrique-2021

290. Please note that Enel decided to terminate the partnership existing with EDF (with effect on 19 December 2012) pursuant to which Enel invested up to 12.5% of the construction, operation, decommissioning and management of nuclear waste costs. EDF consequently reimbursed 658 M€ to Enel (EDF reference document 2012, section 6.2.1.1.3.5).

291. See press release. www.francetvinfo.fr/societe/nucleaire/epr-de-flamanville-le-demarrage-ne-semble-pas-envisageable-avant-2023-et-on-peut-douter-qu-il-demarre-un-jour-selon-negawatt_4362837.html

292. AREVA, a company historically specialised in the nuclear propulsion and reactors, treatment, recycling, fuel assembly and enrichments fields. This company has undergone an extensive restructuring in the course of 2017, which led to (i) the creation of Orano, a 40% held company operating all along the nuclear fuel cycle and (ii) the divestment of the former nuclear reactor activity to EDF. Despite this restricting, AREVA has maintained its involvement in the development of an EPR project in Finland (called OL3).

293. See section 1.1 of the annual activity report available on www.orano.group/docs/default-source/orano-doc/finance/publications-financieres-et-reglementees/2017/orano_rapport-annuel-activite_31-12-17_avec-annexes.pdf?sfvrsn=14d9a171_12

294. See www.framatome.com/EN/businessnews-1074/closing-of-the-new-np-divestment.html

295. *In French, "installations nucléaires de base"*

296. Articles R. 593-1 *et seq.* of the French Environmental Code.

297. Article L. 593-7 of the French Environmental Code.

298. Article L. 593-14 of the French Environmental Code.

299. Article L. 593-18 of the French Environmental Code.

300. Articles L. 593-19 and L. 593-20 of the French Environmental Code.

301. Article L. 593-21 of the French Environmental Code.

302. Article L. 596-1 *et seq.* of the French Environmental Code.

303. See www.pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=163

304. See www.pris.iaea.org/PRIS/CountryStatistics/ReactorDetails.aspx?current=164

305. Law No. 2006-739 of 28 June 2006 codified in articles L. 542-1 *et seq.* of the French Environment Code as modified by the Ordinance No 2016-128 dated of 10 February 2016.

306. Articles D. 594-1 *et seq.* of the French Environmental Code.

307. Such as bonds, claims or securities issued or guaranteed by a Member State of the European Community or of the OECD, or shares and other securities giving access to the share capital of companies whose headquarters are based in a Member State of the European Community or the OECD.

308. Article L. 594-4 and 594-5 of the French Environmental Code.

309. Paris Convention relating to civil liability in the nuclear field dated 29 July, amended on 28 January 1964 and 16 November 1982 and effective from 1 April 1968.

310. Brussels Convention Supplementary to the Paris Convention of 29 July 1960 signed on 31 January 1963 covering only damages suffered in countries that are party to the Brussels Convention.

311. Articles L. 597-1 *et seq.* of the French Environmental Code.

312. Protocol dated 12 February 2004 to Amend the Paris Convention on Third Party Liability in the Field of Nuclear Energy of 29 July 1960, as amended

313. Article 130 of the Energy Transition Law.

314. Article L. 597-17 of the French Environmental Code.

315. Vienna Convention on Civil Liability for Nuclear Damage signed on 21 March 1963, effective from 21 May 1963 and amended on 12 September 1997.

316. Articles 1 and article 2 of the Paris Convention.

317. Panorama of Renewable Power in France in 2021 (see www.rte-france.com/analyses-tendances-et-prospectives/le-panorama-de-lelectricite-renouvelable#Lesdocuments).

318. Panorama of Renewable Power in France in 2021 (see www.rte-france.com/analyses-tendances-et-prospectives/le-panorama-de-lelectricite-renouvelable#Lesdocuments)

319. The PPE sets the following targets of "installed power" in 2023 per source of renewable energy: 18.200-20.200MW for photovoltaic energy; 21.800-26.000MW for on-shore wind energy; 3.000MW for off-shore wind energy; 25.800-26.050MW for hydroelectricity; 790-1.040MW for wood energy and 237-300MW for methanation. www.ecologique-solidaire.gouv.fr/sites/default/files/PPE%20int%C3%A9gralit%C3%A9.pdf

320. Guidelines on State aid for environmental protection and energy 2014-2020, no. 2014/C 200/01.

321. Decrees no. 2016-682 dated 27 May 2016 and no. 2016-691 dated 28 May 2016 as modified by the Decree no. 2016-1726 dated December 14, 2016 and by the Decree no. 2018-112 dated 16, February 2018.

322. Articles L. 314-6-1 and R. 314-52-1 to R. 314-52-11 of the Energy Code.

323. Order dated 20 September 2016 relatif à l'agrément de la société Enercoop as modified by an Order Dated June 19, 2018 and Order dated 31 October 2016 *relatif à l'agrément de la société Hydronext*, Order dated April 7, 2017 relatif à l'agrément de la société BHC Energy, Order dated 21 March 2017 relatif à l'agrément de la société Union des producteurs locaux d'électricité,Order dated 7 April, 2017 relatif à l'agrément de la société BHC Energy, Order dated 27 April 2017 relatif à l'agrément de la société Energies Libres Grands Comptes, Order dated 6 June 2017 relatif à l'agrément de la société JOUL, Order dated 3 August 2017 relatif à l'agrément de la société Direct Energie and Ordre dated 24 August 2017 relatif à l'agrément de la société BCM Energy

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325. ECJ, 19 December 2013, *Association Vent de colère!*, no. C-262/12.

326. CE, 15 April 2016, *Association Vent de colère ! Fédération nationale et autres*, no. 393721.

327. Commission, press release dated 24 March 2014.

328. Order dated 17 June 2014 *fixant les conditions d'achat de l'électricité produite par les installations utilisant l'énergie mécanique du vent implantées à terre*.

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331. Articles L. 314-18 *et seq.* of the Energy Code.

332. Articles R. 314-1 *et seq.* of the Energy Code.

333. Article R. 314-7 of the Energy Code.

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335. Articles L. 314-7 and L. 314-24 respectively of the Energy Code.

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337. See www.ec.europa.eu/competition/state_aid/cases1/202146/SA_50272_509FC07C-0000-CFA6-A4E7-F412831B911A_235_1.pdf.

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339. Order dated 23 November 2011 *fixant les conditions d'achat du biométhane injecté dans les réseaux de gaz naturel*.

340. Order dated 26 April 2017 *modifiant l'arrêté du 23 novembre 2011 fixant les conditions d'achat du biométhane injecté dans les réseaux de gaz naturel*.

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342. Article L. 446-3 of the Energy Code.

343. Articles D. 446-17 *et seq.* of the Energy Code.

344. Article D. 446-17 of the Energy Code.

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349. Article R. 425-29-2 of the Urban Planning Code.

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Energy law in Germany

Recent developments in the German energy market

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With the gas supply crisis in Europe, the biggest energy supply discussion of the past few decades has occurred in Germany. In this context, several topics have been discussed. For example, liquefied natural gas ("LNG") to cover Germany's future gas consumption, the import stop of oil from Russia, the further conversion of coal into electricity, the postponement of the nuclear phase-out, and also the now long-term view on hydrogen and renewable energies. In the future, hydrogen and renewable energies will provide a climate-neutral and secure energy supply, and reduce Germany's dependence on foreign energy imports. This article presents Germany's developments since February 2022, in the form of a timeline that chronologically reflects the impact of the conflict in Ukraine on energy sources and policies in Germany.

Climate action and the gas emergency plan

In March 2022, the Federal Ministry for Economic Affairs and Climate Action (*Bundesministerium für Wirtschaft und Klimaschutz*) ("BMWK") published a draft bill proposing changes to bring the regulation in line with the recently introduced Immediate climate action programme for 2022 (*Klimaschutz Sofortprogramm*) (*Gesetz zur Änderung des Energiewirtschaftsrechts im Zusammenhang mit dem Klimaschutz-Sofortprogramm und zu Anpassungen im Recht der Endkundenbelieferung*). The proposed amendments include the subjects of end customer supply, grid development planning and digitisation and network development in the transmission and distribution network. The new law is in place since 29 July 2022.

The Federal Network Agency ("BNetzA") declared the early warning level of the Gas Emergency Plan. The 'Gas Emergency Plan for the Federal Republic of Germany' is based on the so-called European SoS Regulation, ie Regulation (EU) 2017/1938 of the European Parliament and of the Council, of 25 October 2017, concerning measures to safeguard Germany's security of gas supply. The emergency plan has three escalation levels (early warning level, alert level, and emergency level). Each level allows for more significant government measures depending on how serious the supply situation in Germany is (eg the second stage allows for close market monitoring while the third stage allows for state-regulated gas distribution and thus effectively leverages the market).

Germany has the largest gas storage capacity in the European Union ("EU") (24 billion cubic metres ("bcm")), something the German Federal Parliament (*Bundestag*) sought to maximise by passing legislation in March 2022 to force gas infrastructure operators to fill storage facilities to certain levels throughout the year in order to avoid shortages during winter.

A hydrogen supply chain to Germany was also established. Germany is currently relying on international cooperation as part of its national hydrogen strategy, ie from Africa and the UAE.

The Easter package

The Easter Package was introduced on 6 April 2022 and contains three draft bills from the German Federal Government ("Federal Government"). The main amendment of the Easter Package aims to raise the 2030 target of climate neutrality to 80% and achieve near climate neutrality in electricity generation by 2035. In line with this, the development paths and electricity quantity paths were increased.

On 12 April 2022, the Federal Cartel Office ("BKartA") announced that it had launched an ad hoc investigation into the petroleum sector. This is because during the Russian invasion of Ukraine and the period of rising energy prices in Germany, crude oil prices, refinery sales prices, and prices at gas stations increased significantly.

In addition, the BMWK appointed the BNetzA as trustee for Gazprom Germania. BNetzA was appointed as trustee due to unclear legal relationships as well as the violation of the notification obligation within the framework of the Foreign Trade and Payments Ordinance (FDI filing). Gazprom Germania operates critical infrastructure in Germany and is therefore of 'outstanding' importance for the German gas supply. The BNetzA exercises all voting rights from shares in Gazprom Germania, while the voting rights of Gazprom Germania's shareholders continue to be excluded for an indefinite period of time. This decision shows that the BMWK were prepared to resort to "old-fashioned" means like foreign trade law early on in the gas crisis.

LNG acceleration act

With the Act to Accelerate the Use of Liquefied Natural Gas (*LNG-Beschleunigungsgesetz*), LNG approval procedures and the awarding of public contracts and concessions should be completed faster than under current legislation. According to the BNetzA, by the end of 2022 two floating LNG terminals will begin operating, creating an estimated capacity of 13bcm of gas by 2023.

Furthermore, the 27 EU Member States agreed on an embargo affecting the majority of oil imports from the Russian Federation. Germany aims for a complete import stop by the end of 2022 and plans to be entirely independent from Russian oil by 2024.

Gas emergency plan alert level

The BNetzA declared the alert level (*Alarmstufe*) of the Gas Emergency Plan (*Notfallplan Gas*) on 23 June 2022. Since then, the BNetzA has been providing regular updates on the filling levels of gas storage facilities in Germany. On 1 July 2022, the fill level was 61%. On 16 August 2022, the fill level was 76.79%. After the declared second stage (alert level), a nationwide gas distribution by the Federal Government (through the BNetzA) is the final and third stage and the market will be lifted out. At the time of the alert level, Nord Stream I gas flows were only at 40% and were scheduled to be completely shut down for maintenance from 11 to 21 July 2022. After maintenance, Nord Stream I gas flows were further reduced to 20% of the maximum capacity and then to 0%. According to the BNetzA, this would mean that the legal requirement of having the fill levels at 90% in November 2022 (see Section 35b(1) EnWG) would not be achievable.

The Federal Government provides the market area manager of Trading Hub Europe with a credit line of €15 billion via the KfW Development Bank ("KfW") to secure the filling of the gas storage facilities.

End of the EEG levy and gas network development plan

From 1 July 2022, electricity consumers in Germany no longer have to pay the Renewable Energy Act levy ("EEG levy") (Act to reduce the cost burdens of the EEG surcharge and to pass on this reduction to end consumers) (*Gesetz zur Absenkung der Kostenbelastungen durch die EEG-Umlage und zur Weitergabe dieser Absenkung an die Letztverbraucher*). From 2023, the EEG levy will be permanently reduced to zero with the EEG 2023.

On 10 July 2020, BNetzA opened a consultation on the Gas Network Development Plan 2020-2030. This plan, put together by the transmission system operators (TSOs), focusses on key aspects of growth for the gas network in Germany, such as an uninterrupted supply, increased storage capacity, and the development of gas power plants within the next ten years. The Gas Network Development Plan 2020-2030 comprises 215 measures with an investment volume of about €8.5 billion. The additional proposed measures are largely related to planned LNG terminals, the expansion measures necessary to green gases, the supply in Baden-Wurttemberg and the security of supply in the Netherlands, Switzerland and Italy.

As of 22 July 2022, the Federal Government holds a 30% share of Uniper. The Federal Government adopted a stabilisation package to ensure Germany's energy supply. The package totals about €15 billion and covers an increased KfW loan as well as additional equity.

On 29 July 2022, gas fill levels were again increased by ministerial decree based on the Gas Storage Act. Storage facilities must now be filled by 80% on 1 October 2022, 90% by 1 November 2022 and 40% by 1 February 2023. Trading Hub Europe GmbH must gradually fill the gas storage facilities.

Additional energy saving measures

On 18 August 2022, the Federal Government announced a reduction in value tax from 19% to 7% on gas to relieve consumers (implemented on 29 September 2022).

In scope of the Gas Price Adjustment Ordinance (*Gaspreisanpassungsverordnung*) introduced based on Section 26 of the Energy Security Act, a gas levy of 2.419cents/kWh will be introduced in October 2022, allowing gas importers to pass on additional costs to their customers. In this context, importers can only register 90% of their costs from replacement procurement due to lost Russian gas supplies for the levy.

BMWK, Uniper, RWE and EnBW/VNG signed a memorandum of understanding (MoU) on LNG terminals in Brunsbüttel and Wilhelmshaven in which they committed themselves to provide necessary quantities of gas.

Moreover, several private energy saving measures such as lowering the minimum temperature in work and public places to 19 degrees were introduced.

€200 billion economic defence shield

On 21 September 2022, the Federal Government agreed on an extended rescue package, which means the takeover of around 99% of Uniper's capital shares by the Federal Government (*Verstaatlichung*).

The Federal Government announced the end of the gas levy on the night of 29 September 2022. With the end of the gas levy, a new measure was also announced on 29 September 2022, a €200 billion package for measures against high energy prices. The aim of the gas package is to reduce gas costs for end consumers and the industry. However, the Federal Government has not to date agreed on how to achieve this goal. As an initial step, an expert commission was implemented to develop a sustainable plan on how to spend the €200 billion. The expert commission recommend a one-time payment for every gas user in December as well as a gas price brake, effective from January 2023 for the industry and from March or April 2023 for end consumers.

On 15 September 2022, the BKartA declared that there are no competition concerns regarding the planned cooperation between Uniper, RWE and EnBW/VNG on that matter. The latest amends of the EnSiG, introduced in September 2022, intend to further reduce gas consumption by increasing electricity generation from renewable energies.

Due to recent developments in the electricity market, a cap on the electricity price of €180/MW was agreed on 30 September 2022 by the Council of the EU.

At the end of September, leaks were discovered in the Nord Stream pipelines. There is currently an ongoing investigation, with evidence being collected and data on the environmental, climate and economic impact being analysed. As of October 2022, Germany and the EU have not announced any repair measures or consequences as a result of the suspected sabotage.

Energy security act 3.0

The EU regulations including rules to skim off windfall profits in the electricity market and solidarity levy on energy producers are one of the emergency measures to curb the high energy prices. The Commission proposed a proposal of an "autumn package", which includes a gas price brake.

The German Federal Council (*Bundesrat*) passes the final amendment to the Energy Security Act. The aim is in particular to increase electricity generation from renewable energies and transmission capacities in the electricity grid. The Energy Security Act was originally passed in 1975 and was designed to respond to the oil crisis. With the current gas crisis, the German government has attempted to adapt this basis accordingly. It gives the authorities far-reaching authorisations for energy crisis management, inter alia trust administration and, under narrow conditions, the expropriation for critical infrastructure is possible. In contrast to the Gazprom Germania case, however, trust administration and expropriation are not due to a breach of the (FDI) filing obligation but (without a breach of the respective undertaking) in the event of a supply crisis.

On 17 October 2022, the German Chancellor decided by directive authority that all three nuclear power plants: Isar 2, Neckarwestheim 2 and Emsland, should continue to operate until 15 April 2023. This put an end to the discussion about the nuclear phase-out and continued operation in Germany.

Nuclear phase-out postponed

On 11 November 2022, the October decision by directive authority of the German Chancellor was also adopted by the German Bundestag, and the operation of the three active nuclear power plants Emsland, Isar 2 and Neckarwestheim 2 was legally binding and extended until 15 April 2023.

Further, in order to secure the gas supply in Germany, on 14 November 2022 the Federal Government transferred the gas company Securing Energy for Europe GmbH (SEFE) (formerly Gazprom Germania) into the ownership of the Federal Government. To implement this, the BMWK used capital measures under the Energy Security Act.

A draft law to accelerate the brown coal phase-out in the Rhenish coalfield was also passed in November. This is intended to bring forward the brown coal phase-out in the Rhenish mining area by about eight years, ie to 2030. The decision resulted from a political agreement between the BMWK, the state counterpart (the North Rhine-Westphalia Ministry of Economics) and RWE AG, and the discussions regarding the brown coal mining operation in Lützerath.

Gas and electricity price brakes

On 24 December 2022, the legislation on gas and electricity price brakes entered into force. These price brakes apply from March 2023, and also retroactively cover the months of January 2023 and February 2023.

This will limit the gas price for private households, small and medium-sized enterprises for 80% of the previous year's consumption to 12cents/kWh. Industrial customers will receive 70% of their natural gas consumption of 2021 from their suppliers at a guaranteed 7cents/kWh from January 2023.

The electricity price for households and small businesses with an annual consumption of up to 30,000kWh is capped at 40cents/kWh. This applies to a quota amounting to 80% of the previous year's consumption. For medium-sized and large companies with an annual consumption of more than 30,000kWh, the price cap is 13cents/kWh, plus grid charges, taxes, levies and surcharges. This applies to a quota amounting to 70% of their consumption in 2022.

In addition, two decisions of the European Commission on state aid law were issued in favour of Germany. Firstly, the European Commission approved the amendments to the Renewable Energy Sources Act (EEG 2023) and the Wind Energy at Sea Act (WindSeeG 2023) under state aid law. The Federal Government's participation in the energy utility Uniper SE was also approved and implemented. As decided in September 2022, the Federal Government acquired around 99% of the shares in Uniper. The European Commission approved the aid measure under state aid law on 20 December 2022.

January to March 2023

On 20 January 2023, the Floating Storage and Regasification Unit (FSRU) in Brunsbüttel entered the commissioning procedure. The third German LNG terminal can inject liquefied gas from LNG tankers into the German gas grid after regasification and has a potential capacity of 7.5bcm annually. Full capacity utilisation and functionality is planned for the end of 2023.

On 30 January 2023, the Federal Cabinet agreed to the draft law on the implementation of the EU Emergency Regulation (Regulation EU 2022/2577) proposed by the BMWK. The aim is to speed up the procedure for expanding wind energy, as well as offshore connection lines and electricity grids. The proposal provides for amendments to the Wind Energy Area Requirements Act, the Wind Energy at Sea Act, and the Energy Industry Act. This draft is to be implemented into the current legislation by the Bundestag.

In February 2023, the Dutch electricity grid operator TenneT was negotiating with the German government on the sale of its German subsidiary and electricity lines in Germany to the state. This is due to the high capital equity requirement for the energy transition, the financing of which is to be redistributed in this way.

In addition, Austria and Germany agreed in a bilateral agreement on joint responsibility for the use and filling of two natural gas storage facilities as well as the transport of the stored gas volumes in the event of a shortage.

On 10 March 2023, the BMWK presented a draft of the photovoltaic strategy, which is divided into eleven fields of action. The draft contains, among other things, support for rooftop and ground-mounted photovoltaics as well as 'balcony PV', simplification of tenant electricity and communal building supply, and the acceleration of grid connections. Stakeholders had until 24 March 2023 to submit comments on the draft. The final photovoltaic strategy is to be presented in May 2023.

Also in March, the Federal Administrative Court dismissed Rosneft's lawsuit against the trusteeship order. According to the Federal Administrative Court, the order of trusteeship by the BMWK was lawful and appropriate.

Additionally, it was announced in March that Germany had achieved its climate target for 2022 and had emitted less greenhouse gases than in the previous year. The overall reduction in emissions was mainly due to a decline in industry, as emissions in other sectors such as transport and energy had seen an increase.

Overview of the legal and regulatory framework in Germany

A. Electricity

A.1 Industry structure

Nature of the market

Germany has about 222.38GW[1] in generation capacity and consumes about 503,8TWh[2] of electricity per year. In 2021, Germany generated about 505.3TWh of electricity in total.[3] According to figures published by Eurostat; in 2019, Germany had the highest level of net electricity generation among the European Union ("EU") Member States, accounting for 20.8% of the total electricity generated in the EU.[4] In addition to being the largest electricity market in the EU, Germany also hosts the European Energy Exchange ("EEX"), the largest energy trading platform in Europe (for further details on the EEX, see section C).

Key market players

Generators

The German electricity market is fully liberalised; however, it is still largely dominated by the five largest providers: Uniper (E.ON spun-off its conventional energy sources and global energy trade businesses into Uniper SE in 2016), RWE, Vattenfall, LEAG and EnBW, all of whom have a collective market share of 65.3% (as at 2020).[5]

In particular, the market share of E.ON and RWE has long been the subject of discussions and close scrutiny. In 2008, the federal competition authority, the Federal Cartel Office (*Bundeskartellamt*) ("BKartA"), prohibited E.ON from acquiring shares in Stadtwerke Eschwege, and the Federal Court of Justice (*Bundesgerichtshof*) ("BGH") confirmed that E.ON and RWE formed a market-dominating duopoly in the German market for the generation and importation of electricity.[6] However in 2020, RWE and E.ON completed an asset and business area swap with E.ON, taking on the remaining networks and distribution business including the incorporation of Innogy, an energy company based in Essen (formerly a subsidiary of RWE). The renewable assets of Innogy as well as E.ON's renewable energies business passed to RWE under the deal.[7]

Germany was a net exporter of electricity in 2021, with a net export of 17.4TWh which can be broken down into 57.0TWh of exported electricity and 39.6TWh of imported electricity. Germany's net exports decreased by 5.9% compared to 2020 (18.5TWh),[8] raising the prospect that its dependency on neighbours could rise in future as it switches off more coal and nuclear power stations.[9]

Network operators

The German electricity transmission system spans about 37,000km and is operated by four transmission system operators (*Übertragungsnetzbetreiber*) ("TSOs"): Amprion GmbH (74.9% of which is owned by institutional investors and 25.1% by RWE), TenneT TSO GmbH (owned by the Dutch state-owned TSO, TenneT), TransnetBW GmbH (formerly trading as EnBW Transportnetz AG and part of the vertically integrated EnBW) and 50Hertz Transmission GmbH (80% owned by the Belgian TSO Elia, which in turn is indirectly held by Belgian public entities and 20% owned by KfW Bank Group).

There are more than 800 distribution system operators (*Verteilnetzbetreiber*) ("DSOs") in Germany.

Regulatory authorities

The Federal Network Agency (Bundesnetzagentur) ("BNetzA") is the regulator for the German energy industry. Its competencies are mainly set out in the Energy Industry Act (*Gesetz über die Elektrizitäts- und Gasversorgung (Energiewirtschaftsgesetz)*) ("EnWG") of 13 July 2005. BnetzA's jurisdiction includes, inter alia, ensuring non-discriminatory third-party access to networks as well as the monitoring and enforcing of the use-of-system charges levied by market participants. BNetzA is mainly responsible for monitoring the network operators that supply more than 100,000 customers and/or operate in more than one federal state (*Bundesland*).

In addition, there are regional regulatory authorities (*Landesregulierungsbehörden*) that are responsible for monitoring smaller network operators.

BKartA and the respective state competition authorities (*Landeskartellbehörden*) effectively have concurrent jurisdiction with BNetzA in the energy sector, as all issues other than those pertaining to the regulation of the network itself, such as, price control and mergers, fall within the competency of the antitrust authorities. In September 2021, the Court of Justice of the EU ("CJEU") found that Germany had failed to properly implement various provisions of the EU Electricity Directive (2009/72/EG) and the EU Natural Gas Directive (2009/73/EG) (together the "EU Energy Directives") of the Third Energy Package ("TEP"), ruling that Germany has given the national regulatory authority, BNetzA, insufficient independence in enforcing energy regulation, thereby leaving the area open to political influence (ref: C-718/18). The repercussions of the judgment are pending.

Legal framework

Legislation and regulation

EnWG is the legal backbone of the energy sector in Germany and provides its basic legal framework. It is subject to regular revisions and changes. The most notable changes were a result of the transposition of the TEP into German law in 2011, the introduction of provisions regarding network development plans to be developed by TSOs in 2012, and amendments introduced by Article 1 of the Electricity Market Law (*Strommarktgesetz*) in 2016 which, among other things, set out new principles for the electricity market. In May 2019, the Law to accelerate the expansion of power lines (*Gesetz zur Beschleunigung des Energieleitungsausbaus*) led to changes in the area of access and the construction of power lines.[10]

In addition, there was an important amendment (Law on the Implementation of Requirements under EU Law and the Regulation of pure Hydrogen Networks in Energy Industry Law) in 2021 implementing, among other things, regulations for pure hydrogen networks and operators of cross-border stand-alone interconnectors.

In March 2022, the Federal Ministry for Economic Affairs and Climate Action (*Bundesministerium fur Wirtschaft und Klimaschutz*) („BMWK") published a draft bill proposing changes to bring the regulation in line with the recently introduced Programme for immediate climate action (*Klimaschutz Sofortprogramm*) (*Gesetz zur Änderung des Energiewirtschaftsrechts im Zusammenhang mit dem Klimaschutz-Sofortprogramm und zu Anpassungen im Recht der Endkundenbelieferung*). The proposed amendments include the subjects of end customer supply, grid development planning and digitisation and network development in the transmission and distribution network.[11] The new law has been in place since 29 July 2022.

The EnWG contains 12 parts that address, in turn: general provisions (Part 1, *Allgemeine Vorschriften*); unbundling (Part 2, *Entflechtung*); the regulation of grid operations (Part 3, *Regulierung des Netzbetriebs*); level specifications for gas storage facilities and ensuring security of supply (Part 3a, *Füllstandsvorgaben* für *Gasspeicheranlagen und Gewährleistung der Versorgungssicherheit*), energy supply to final customers (Part 4, *Energielieferung an Letztverbraucher*); planning procedures and wayleaves (Part 5, *Planfeststellung, Wegenutzung*); security and reliability of energy supply (Part 6, *Sicherheit und Zuverlässigkeit der Energieversorgung*); regulatory authorities (Part 7, *Behörden*); procedures and remedies in excessively long judicial proceedings (Part 8,*Verfahren und Rechtsschutz bei* überlangen *Gerichtsverfahren*); miscellaneous provisions concerning publicly owned undertakings, closed distribution systems and the consumer ombudsman (Part 9, *Sonstige Vorschriften*); transparency provisions (Part 9a, *Transparenz*); and evaluation and reporting matters (Part 10, *Evaluierung, Schlussvorschriften*).

The EnWG is supplemented by numerous ordinances, which in turn contain detailed rules and provisions on individual aspects of the sector, such as the:

- ordinance on access to the electricity network (*Stromnetzzugangsverordnung*) ("StromNZV");
- ordinance on electricity network access fees (*Stromnetzentgeltverordnung*) ("StromNEV");
- ordinance on incentive regulation (*Anreizregulierungsverordnung*) ("ARegV"); and
- ordinance on the network access of power plants (*Kraftwerks-Netzanschlussverordnung*) ("KraftNAV").

Contractual framework

Entities (including generators, suppliers and consumers) wanting access to the energy supply grid for power in Germany must enter into network usage agreements (*Netznutzungsverträge*) with the relevant operator of the energy supply grid. The content of the network usage agreement is subject to the provisions of StromNZV. The transmission of electricity from generator to supplier (or to the consumer, as the case may be) requires the relevant parties to enter into two separate network usage agreements, the first between the generator and the operator of the relevant energy supply grid, and the second between the operator of the relevant energy supply grid and the relevant supplier or consumer who can offtake electricity at specified exit points. Each network usage agreement must be allocated to a specific balancing group (established by balancing agreements, see below in this section) within a balancing zone.

To prevent individual final customers from having to enter into a separate network usage agreement with the relevant grid operator, retail electricity suppliers often enter into supplier framework agreements (*Lieferantenrahmenvertrag*) that allow them to offtake electricity at some (or all) exit points from the relevant grid operator's grid. To harmonise the contracting and processing of grid usage, BNetzA developed a model contract that forms the compulsory framework for all network usage agreements and supplier agreements as of 1 January 2016. The current version of the model contract has been valid since 1 April 2022.

Furthermore, regarding the transport of energy via the grids to the point of withdrawal by the supplied customer, a network connection agreement (*Netzanschlussvertrag*) between the relevant grid operator and the connected customer is required whereby the usage of the grid access (*Anschlussnutzung*) does only in specific cases require a separate access usage agreement (*Anschlussnutzungsvertrag*).

Balancing agreements (*Bilanzkreisverträge*) set out the terms and conditions under which the TSO of the relevant balancing zone has to manage the entry and exit of electricity in order to maintain a stable network. Such agreements between the relevant TSO and the responsible balancing group manager must be completed in accordance with StromNZV which set out the contractual minimum requirements. The BNetzA has published a standard balancing agreement (current valid version from 1 August 2020 (ref: BK6-18-061)). Where there is an imbalance between the entry and exit of electricity within a balancing group, the relevant system can be offset by corresponding imbalances of other balancing groups within the same balancing zone. If this is not possible, the relevant TSO must provide additional system electricity to balance the network or reduce the volume of electricity on the grid.

Power purchase agreements ("PPAs") are not subject to specific statutory regulation; however, they are subject to the general provisions of German law, including the Act against Restraints on Competition (*Gesetz gegen Wettbewerbsbeschränkungen*) ("GWB").

Implementation of EU electricity directives

The German Legislature has transposed the Third Electricity Directive into German law.

Ownership unbundling

Amendments to EnWG, which transposed the Third Energy Directive into German law, provide for all three unbundling options of the TEP, ie full ownership unbundling ("FOU"), the independent system operator model ("ISO"), and the independent transmission operator model ("ITO").

Of the four electricity TSOs in Germany:

- TenneT TSO GmbH was not initially certified as a Transport Network Operator (*Transportnetzbetreiber*), although it asserted it complied with the requirements of the FOU regime. BNetzA eventually certified TenneT TSO GmbH as a Transport Network Operator on 3 August 2015.
- 50Hertz has been certified as Transport Network Operator since 9 November 2012. It is ultimately owned and jointly controlled by the Belgian electricity TSO, Elia System Operator ("Elia") (80%), and the Industry Funds Management Global Infrastructure Fund ("IFM Global Infrastructure Fund") (20%). In spring 2018, Elia announced that IFM Global Infrastructure Fund would also sell its remaining 20% stake in 50Hertz. The purchaser was the German state-owned bank KfW (*Kreditanstalt fur Wiederaufbau*).
- Amprion is owned 25.1% by RWE AG, a company active in the generation and supply of electricity and gas, and 74.9% by M31Beteiligungsgesellschaft mbh & Co. Energie KG, a joint venture of numerous institutional investors. Amprion was certified as Transport Network Operator complying with the ITO model on 9 November 2012. The BNetzA stipulated various conditions (*Auflagen*) in its certification decision concerning Amprion's effective administrative and practical independence from RWE.
- TransnetBW is understood to be structured as an ITO and was certified by BNetzA on 11 April 2013, although various conditions were imposed.[12]

The language of the German legislation implementing the Electricity Internal Market Directive (part of the TEP) generally mirrors that of the Electricity Internal Market Directive itself; however, the EU Energy Directives set out specific requirements for the term of a vertical integrated undertaking which plays a fundamental role in connection with unbundling requirements. In September 2021, the CJEU held that the German concept of a vertically integrated undertaking is too narrow, particularly in that it only takes into account undertakings which operate in the EU (ref: C-718/18). The German Legislature must take action to comply with the judgement.

A.2 Third party access regime

Network connection

Under the EnWG, energy supply grid operators have an obligation to physically connect, among other things, electricity generators, other network operators and end consumers to the grid.[13]

Connections must be provided on technical and commercial terms that are appropriate, non-discriminatory, transparent and no more unfavourable than those applied in similar cases by energy supply grid operators for services to their own, affiliated, or associated companies. Access may only be refused for operational, economic or technical reasons, and justification for any denial of access must be given by written notice to the relevant applicant.

The connection of power plants (other than offshore wind parks) with more than 100MW of effective electricity output to electricity networks with a voltage higher than 110kV is subject to the provisions of KraftNAV, which mainly set out the parameters of the network connection agreement for such plants, cost allocation to the connected user and a timetable for the relevant connection.

Connection of offshore wind farms

TenneT TSO GmbH and Amprion GmbH are the TSOs responsible for connecting offshore wind farms in the North Sea, and 50Hertz Transmission GmbH is responsible for connecting those in the Baltic Sea.

Until the end of 2012, TenneT and 50Hertz were under an obligation to have the grid connection ready when a relevant wind farm became operational. In addition, the relevant TSO had to bear the cost for installing the connection. This, however, created significant organisational and financial challenges for the TSOs concerned, partly as the approach did not allow for the coordinated extension of the grid offshore and because TSOs were subject to the risk of stranded investments. In addition, TSOs often faced difficulties in connecting offshore wind farms within the required timeframe, thereby exposing the wind farm operators to delays and ultimately loss in revenue.

In order to remedy these issues, the German Legislature adopted an amendment to EnWG, the third amendment law for the reform of energy law provisions (*Drittes Gesetz zur Neureglung energiewirtschaftlicher Vorschriften*) ("Third Amendment Law"), which entered into force on 21 December 2012. The Third Amendment Law introduced a new regime in two main areas:

- general obligation for TSOs to connect offshore wind farms to the grid; and
- liability of offshore TSOs in the case of delayed or interrupted grid connection.

The Third Amendment Law provides that TSOs have to construct offshore grid connections on the basis of an offshore grid development plan, which in turn has to provide a timed roadmap for the offshore extension of the grid (*Netzentwicklungsplan*).

Since 2017, the EnWG has provided a different system for the connection of offshore windfarms. TSOs in whose control area the grid connection of offshore wind turbines is to take place (*anbindungsverpflichtete Übertragungsnetzbetreiber*) must construct and operate the offshore connection lines in accordance with the requirements of the offshore grid development plan and, from 1 January 2019, in accordance with the requirements of the grid development plan and the area development plan (*Flächenentwicklungsplan*) under Section 5 of the Wind Energy at Sea Act (*Windenergie-auf-See-Gesetz*) ("WindSeeG"). The WindSeeG now contains the regulations regarding grid capacity allocation and the corresponding tender volumes.

Since 2017, offshore capacities are subject to tender procedures according to the WindSeeG. Depending on the date of commissioning of the relevant offshore windfarm, the tender regulations differ.

The specific timeline for the construction of the offshore connection line and the respective offshore windfarm is based on the expected completion date of the offshore connection line. After the announcement of the expected completion dates, the TSO must agree with the operator of the respective offshore windfarm on an implementation schedule (*Realisierungsfahrplan*) containing the time sequence for the individual steps for constructing the offshore wind turbine and for establishing the grid connection. The EnWG stipulates information obligations of the relevant TSO and the operator of the offshore wind turbine regarding the progress of the construction of the offshore wind turbine and the establishment of the grid connection. 30 months prior to the expected completion of the grid connection lines, the announced completion dates become binding. Where there is a delay, the corresponding compensation regulations of the EnWG refer to this binding completion date (please see below for further details).

In 2021, new regulations were implemented in the EnWG regarding the grid connection of offshore windfarms in the coastal sea (*Küstenmeer*), which do not fall under the admission procedure part of the WindSeeG. The EnWG stipulates a special grid connection claim for installation operators with a permit according to the Federal Emission Control Act (*Bundesimmissionsschutzgesetz*) ("BImSchG") for the construction of a wind energy plant in the coastal sea. The admission procedural regulations of the WindSeeG are not applicable to these offshore windfarms. The relevant TSOs must, vis-à-vis the holder of a BImSchG-permit for the construction of offshore wind turbines in the coastal sea, construct and operate the grid connection from the substation of the offshore wind turbines to the technically and economically most favorable connection point of the nearest transmission system in the technically and economically most favorable manner.

Furthermore, holders of such a BImSchG-permit for the construction of offshore wind turbines in the coastal sea must only be entitled to a grid connection if the electricity generated on the site in the coastal sea is sold exclusively by way of other direct marketing under Section 21a of the Renewable Energies Act (*Erneuerbare Energien Gesetz*) ("EEG"). Therefore, the grid connection claim in this case only exists if the electricity generated is not subsidised.

Another requirement for such special grid connection claim for BImSchG-permit holder is that a security, under Section 18 of the WindSeeG, has been provided to the BNetzA, ie €100/kW in relation to the approved amount of the capacity to be installed to secure claims of the TSO who must provide the connection. Bidders must deposit a security amounting to 25 percent of the total sum calculated by this method with the Federal Network Agency by the respective bid date. The awarded bidder must additionally deposit the remaining security amounting to the remaining 75 percent of the total sum with the Federal Network Agency within three months of the award of the contract. A grid connection as explained above is part of the energy supply grid from the time of completion.

The regulations for the procedure of the grid connection of the holders of BImSchG-permits are mainly leaned on the procedure for the construction of offshore grid connection lines as described above. The liability regime under the EnWG provides that the relevant TSOs are to compensate offshore windfarm operators if feed-in from an operational offshore wind energy system is not possible for: (i) more than ten consecutive days due to a disruption in the grid connection from the 11th day of the disruption; or (ii) for more than 18 days during a calendar year, irrespective of whether or not the TSO is responsible for the disruption. Under Section 19 of the EEG, the compensation claim comprises financial losses incurred, amounting to 90% of the direct marketing payment claim, minus 0.4 cents/kWh. The compensation claim does not apply if the operator of the offshore wind turbine is responsible for the disruption. A similar regulation applies in case of delayed completion of the grid connection line. Furthermore, a compensation claim exists in case of maintenance-related disruption.

Operators of offshore windfarms that were awarded in a tender procedure according to the WindSeeG are entitled to claim for compensation provided that the compensation amounts to 90% of the relevant value to be invested (*anzulegender Wert*), as per the WindSeeG, but at least 90% of the monthly market value within the meaning of Annex 1 No. 2.2.3 of the EEG.

Network access

EnWG provides for grid access on non-discriminatory terms on the basis of entry or exit and ex-ante regulated network fees.

Use of system

Network access fees are generally regulated by ARegV, which introduced incentive-based regulation to the German electricity sector. Under ARegV, network access fees are determined by a formula that contains elements of 'non-influenceable' and 'influenceable' costs and contains further multipliers set in accordance with both the individual efficiency of a network operator and a general sector efficiency standard. ARegV also sets an upper revenue limit (*Erlösobergrenze*) for each year of a five-year regulation period (*Regulierungsperiode*). The current regulation period commenced on 1 January 2019.

As a rule, non-influenceable costs are considered by determining the upper revenue limit and can therefore be fully passed on to network users, whereas influenceable costs are subject to passing efficiency standard tests. If network operators do not meet the efficiency standards determined in accordance with ARegV, they have to take measures to increase their efficiency by reducing their variable costs in the relevant regulation period. The required efficiency effort is translated into an annual reduction of the upper revenue limit throughout the relevant regulation period. The upper annual revenue limit is further reduced by a general productivity factor that is defined by sector (*sektoraler Produktivitätsfaktor*, also referred to as PF (t)).

A.3 Market design

The German electricity market is fully liberalised with no regulatory entry barriers. The market structure has changed in recent years as the concentration of market share in the hands of historical incumbents continues to decrease. Despite the ambitions of the energy transition (*Energiewende*), the generation of energy from conventional sources increased by 11.7% in 2021 (compared with 2020), accounting for 57.6%. In 2022, it decreased by 7% to 51.1%, while the generation from coal increased significantly from 17.2% to 31.4% when compared to 2021.[14]

The introduction of the so-called 'Easter Package' is expected to triple the expansion of renewable energies through simplified approval procedures. Additionally, tender quantities until 2028/29 will increase. The share of renewable energies on gross electricity consumption is expected to double by 2030; by 2035 electricity should be obtained from renewable energies almost completely.[15] The German Legislature debated further amends especially regarding the expansion of onshore wind energy, but the discussed Summer Package dissolved in the planning.

The German electricity market is currently a pure energy market; however, a capacity reserve has been newly established which is strictly separated from the electricity market and must ensure a security network for unforeseen and extraordinary events. To avoid any negative effect on the competition and pricing at the electricity market, the capacity reserve only comprises power plants that do not participate in the electricity market. The European Commission ("Commission") approved a capacity reserve up to 2GW, starting on 1 October 2020 with a volume of about 1GW.[16]

A.4 Tariff regulation

The prices for electricity in Germany are determined by the market. The following three components are considered at the calculation of the electricity price for household customers:

- the price for the procurement and distribution of electricity;
- fees for the grid usage; and
- statutory components, eg taxes and the Renewable Energy Act levy ("EEG levy").[17]

Part of the statutory components since the abolition of the EEG levy on 1 July 2022 remain, ie concession fees, the levy in accordance with the German Combined Heat and Power Act (*Kraft-Wärme-Kopplungsgesetz*) ("KWKG" and KWKG levy") and the electricity tax.

Concession fees are charges paid by energy supply companies for granting the right to use public transport routes for the laying and operation of lines used to directly supply energy to end consumers in the municipal area. The permissibility and assessment of the concession fees are regulated by the KAV (*Konzessionsabgabeverordnung*).

Through the KWKG levy, the subsidy under the KWKG for the use of the combined heat and power technology is passed on to the final consumer. It is added to the network charge. In 2022, the levy was 0.378cents/kWh.[18]

Due to recent developments on the electricity market, a cap on the electricity price of €180/MW was agreed on 30 September 2022 by the Council of the EU.[19]

A.5 Market entry

Generation

Depending on the form of generation (eg nuclear, coal, hydro, etc) it may be necessary to obtain various other licences, in particular, for the construction of generation facilities. Under EnWG, companies supplying household customers with energy must notify the relevant authority.

Operation of energy supply grids

The operation of an energy supply grid is a licensable activity under EnWG. Entities wishing to obtain a licence must show that they have the necessary human, technical and financial resources to operate the relevant network in accordance with the legal and regulatory framework. Licences are issued by the competent authority in the relevant federal state.

Certification as transport network operator

Furthermore, entities seeking to exercise the functions of a Transport Network Operator must also apply for certification under Section 4a EnWG. The certification procedure was introduced by the Third Electricity Directive and compliance with the applicable unbundling regime is a condition precedent for certification. The Third Electricity Directive and Section 4a EnWG provide for a dual procedure requiring both BNetzA and the Commission to consent to the relevant certification. On 9 November 2012, BNetzA refused to certify TenneT TSO GmbH as a Transport Network Operator on the grounds that it did not have the necessary financial resources to comply with the relevant legal requirements. From both a German and European perspective, the period during which TenneT was not technically certified as a Transport Network Operator raised a number of questions regarding: (i) the legal consequences of the absence of such a certification; and (ii) the relation between BNetzA decisions and those of the Commission. The BNetzA, however, believed that the missing certification did not prohibit the relevant network operator from operating its transport network as the certification is not an operating licence. The operation of a transport network without being certified constitutes an administrative offence that shall be determined in a separate procedure.[20] In August 2015, BNetzA certified TenneT as a Transport Network Operator.

Sale licence

Section 4 Paragraph 1 of the Law on Electricity Taxation (*Stromsteuergesetz*) ("StromStG") provides that, subject to certain exemptions, any entity supplying electricity or offtaking electricity for its own use must obtain a permit to that effect.

Furthermore, certain electricity is exempted from electricity tax, eg emergency electricity generators, electricity generated in plants of up to 2MW capacity and utilised for the generator's own electricity requirements, and electricity to be used in trains and ship traffic. The supply and offtake of electricity exempted from electricity tax requires an additional permit.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

EnWG reflects the PSOs contained in the Electricity Internal Market Directive. In particular, EnWG provides for a supplier of last resort (*Grundversorger*). Under Section 36 Paragraph 2 EnWG, the role of the supplier of last resort falls to the supply undertaking with the greatest number of household customers in a network area. The supplier of last resort must publish their general terms and conditions, as they may supply all household customers who do not exercise their right to choose a specific tariff or supplier.

Smart metering

The German Metering Operation Act provides, among other things, the regulation for the roll-out of smart meters.

Section 29 of the German Metering Operation Act (*Messstellenbetriebsgesetz*) ("MsbG") stipulates that basic metering point operators (*grundzuständiger Messstellenbetreiber*) (generally the operators of energy supply grids) must install smart meters in certain specified circumstances, such as for end consumers with an annual consumption exceeding 6,000kWh or who control those consumer facilities that can be controlled under Section 14a EnWG (*netzorientierte Steuerung von steuerbaren Verbrauchseinrichtungen*), and power plant operators with an installed capacity exceeding 7kW. Basic metering point operators may install smart meters if it is technically feasible and economically viable to do so for end consumers with an annual consumption of no more than 6,000kWh, and for power plant operators with an installed capacity of between 1kW and 7kW. The mandatory start of roll-out is dependent on the determination of the technical feasibility of installing smart metering systems by the Federal Office for Security in Information Technology (*Bundesamt* für *Informationssicherheit*) ("BSI").

On 7 February 2020, the BSI has issued a general order (*Allgemeinverfügung*) that the technical possibility exists for the installation of smart meters, insofar as: (i) metering points are to be equipped at end consumers at metering points in the low voltage with an annual electricity consumption of no more than 100,000kWh; (ii) no recording load profile measurement (*registrierende Lastgangmessung*) takes place at these metering points; and (iii) no agreement under Section 14a EnWG exists.[21] However, the BSI revoked this general order with the retrospective decision from 20 May 2022 (*Rücknahme*).[22] Nonetheless, the BSI has issued another general order and determined that using an installation of the smart meters available on the market is not associated with significant risks and therefore the continued operation and installation of smart meters is still possible, but there is no further installation obligation.[23]

An objection (*Widerspruch*) has been filed against the revocation decision of the BSI by a metering service provider on 2 June 2022. The impact of this objection on the previous installation obligation, ie the roll-out obligation, is currently unclear.

Electric vehicles

E-mobility is funded in Germany in various ways. Amongst others and in contrast to other motor vehicles, electric vehicles ("EVs") are tax-free for the first ten years, provided they are registered between 18 May 2011 and 31 December 2025 according to Section 3d Paragraph 1 of the Motor Vehicle Tax Act (*Kraftfahrzeugsteuergesetz*) (KraftStG). After the expiry of the exemption, the car tax will amount to 50% of €11.25 (up to 2,000kg), €12.02 (up to 3,000kg) or €12.78 (up to 3,500kg) for each 100cc or part thereof.[24] Since 2015, EV users have benefited from the electro mobility act (*Elektromobilitätsgesetz*) (EmoG), eg with respect to using personal parking spots or bus lanes. EV purchasers are also entitled to a government subsidy, the value of which increased in 2021, to the following:

	Vehicle purchase price <€40,000	**Vehicle purchase Price >€40,000**
Full EVs	€9,000	€7,000
Plug-in Hybrids	€6,500	€5,625

Electric vehicle subsidies 2021[25]

On 13 April 2022, the Federal Ministry of Economics and Climate Protection presented an amended guideline for the promotion of EVs from 2023. It entails the introduction of one general subsidy for EVs that decreases to €4,000 from 2023 and further to €3,000 from 2024 per purchase of an EV, regardless of the purchase price. The subsidy for plug-in hybrids ends on 31 December 2022. The subsidy only applies if a vehicle is held for at least one year. Subsidies for leasing require a leasing period of at least 12 months.[26]

Since June 2019, smaller vehicles with electric drivetrains, such as electric scooters (e-scooters) are permitted on German roads if they satisfy the requirements of the Regulations on Personal Light Electric Vehicles (*Elektrokleinstfahrzeuge-Verordnung*).[27]

A.7 Cross-border interconnectors

Germany has interconnectors with Austria, Switzerland, France, Luxembourg, Belgium, the Netherlands, Denmark, Poland and the Czech Republic. A new interconnector between Germany and the UK is currently being built with construction due to be completed around 2025. Once complete, the project will allow for up to 1.4GW of electricity to move in either direction, enough to power 1.5 million homes over the life of the project.[28]

Due to persistent capacity shortage in those interconnectors, the relevant TSOs have introduced a portfolio of capacity management measures, including:

- market coupling (tight volume coupling across the Central and Western European area ("CWE") and the Nord Pool area);
- explicit auctions for yearly, monthly, daily and intraday transmission capacities (for the Swiss-German interconnector); and
- coordinated explicit auctions based on Net Transfer Capacity (for Central Eastern Europe (Austria, the Czech Republic, Germany, Hungary, Poland, Slovakia, Slovenia)).

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Energy consumption in Germany is dominated by fossil fuels with crude oil and petroleum products accounting for one third of consumption. Crude oil is primarily imported, as not even 2% of demand can be met by domestic production, and imports amounted to about 78.8 million tonnes in 2021.[29] Crude oil imports in 2019 mainly originated from Russia (about 32%), Norway (about 11%) and the UK (about 12%).[30] In May 2022, the 27 EU Member States agreed on an embargo affecting the majority of oil imports from the Russian Federation. Germany aims for a complete import stop by the end of 2022. By 2024, Germany plans to be entirely independent from Russian oil.[31]

Key market players

The oil market in Germany is privatised and there is no state involvement; however, a variety of different companies have refining facilities, and crude oil and semi-finished products are processed in 13 different refineries with a crude oil processing capacity of 101 million tonnes.[32]

Regulatory authorities

There are no specific regulatory authorities with respect to the oil market. The Federal Authority for Economy and export control, ie BAFA, collects data regarding the trade with oil and is responsible for oil stocks and the prevention of a supply crisis. Producers and distributers of oil are supervised by state authorities, for example by Lower Saxony LBEG (*Landesamt* für *Bergbau, Energie und Geologie*) for northern Germany, to prevent environmental damages.

Legal framework

There are no specific regulatory provisions in place in respect of the German oil market. The GWB is applicable to the oil industry and is enforced by the BKartA.

On 12 April 2022, the BKartA announced that it had launched an ad hoc investigation into the petroleum sector. This is because during the Russian invasion of Ukraine and rising energy prices in Germany, crude oil prices, refinery sales prices and prices at the gas station had increased significantly. In the period before the Russian invasion of Ukraine and rising energy prices, the BKartA delivered its last report for its inquiry into the German motor fuel market in 2011. One year later in 2012, the BKartA initiated proceedings against Deutsche BP (and their subsidiary, Aral), ExxonMobil Europe (and their subsidiary, Essa), ConocoPhilips (and their subsidiary, Jet), Shell Deutschland and Total Deutschland based on an allegation that these companies prevented the fair operation of the competitive market and, as a result, hindered independent petrol stations.

In 2012, the BKartA launched another inquiry into the oil sector focusing on refineries and wholesale. However, in 2013 the BKartA launched the Market Transparency Unit for Fuels (*Markttransparenzstelle fur Kraftstoffe*), an information portal that records the price of fuel at German petrol stations in real time and releases the information to consumer information services.[33] The aim of the transparency unit is to provide customers with up-to-date information on prices in their local area to enable them to find the best value, and to encourage competition between suppliers.[34] The sector inquiry was then postponed due to the establishment of the Market Transparency Unit for fuels.[35]

In April 2022, the BKartA initiated an ad hoc sector inquiry with focus on refineries and wholesale to investigate reasons for price development and their impact on the massive increase in pricing at gas stations. Following the Russian invasion of Ukraine, refinery sales prices and prices at the service stations diverged significantly.[36]

Political discussions about introducing an excess tax have been rejected by the Federal Ministry of Finance.

Gas

Nature of the market

Germany is the EU's largest gas market and consumed 1,013 billion kWh (about 1,000TWh) of gas in 2021.[37]

The German gas market is almost entirely liberalised and under the current model customers can select their gas supplier. In 2021, an end consumer in Germany could choose from 133 suppliers (129 in 2019) on average in their respective network area. German households were able to choose from 113 suppliers (109 in 2019) in their respective network in the same year.[38] In the German retail market for gas, more than half of the suppliers are local and regional utilities. The 2021 Monitoring Report, as with previous monitoring reports, showed that competition in the retail gas market has intensified. A total of about 1.6 million household customers changed supplier in 2020 which was again a new high. BKartA assumes that none of the gas suppliers currently holds a market-dominating position.[39]

Gas network operators must submit a report to BNetzA in relation to all interruptions in their networks by 30 April every year. BNetzA and BKartA concluded in the Monitoring Report 2021 that despite an increase in disruptions, overall gas supply in Germany in 2020 had been of a high quality. In 2020, the average interruption in gas supplies per final customer (the System Average Interruption Duration Index ("SAIDI") value) increased to 1.09 minutes, up from 0.98 minutes in 2019. As a result, customers experienced on average just over one minute of interruption to their gas supply throughout the year.[40]

Key market players

The German gas market, similar to the electricity market, is characterised by a multi-tier structure consisting of vertically integrated supply chains that are heavily concentrated (ie where a small number of companies hold a large market share) alongside a large number of regional and local providers. The wholesale market is broadly split between five large wholesale companies (E.ON/Uniper, RWE, VNG, Wingas and BEB), all of which import gas from different sources. None of these suppliers has a dominant market position and the share of independent, smaller suppliers is constantly increasing. As of 22 July 2022, the Federal Government of Germany ("Federal Government") holds 30% of Uniper.[41] On 21 September 2022, the Federal Government agreed on an extended rescue package, which means the takeover of about 99% of Uniper's capital shares by the Federal Government (*Verstaatlichung).*[42]

To date, there has only been a limited amount of competition in the large customer market in Germany. This is due to a lack of available access to gas production activities for alternative suppliers and the existence of long-term supply contracts between the incumbent companies and distributors, which prevent new suppliers from gaining access to customers. However, the ongoing liberalisation of the German gas market has created some new dynamics, with new gas suppliers pushing their way into the market, increasing competition and providing enhanced advantages for customers. New gas suppliers have positioned themselves by using radical pricing policies in comparison to the traditional suppliers.

Shale gas

Shale gas production first took place in 1961 and has since been carried out several times; however, Germany does not currently produce shale gas. Albeit certain companies (eg Exxon Mobil, Wintershall, and since 2019, Wintershall Dea) have investigated potential shale gas reserves. In October 2010, the Federal Government asked the Federal Institute for Geosciences and Natural Resources (*Bundesanstalt fur Geowissenschaften und Rohstoffe*) ("BGR") to assess the potential of German shale gas deposits. In May 2012, the BGR presented its study, the NIKO-project, which estimated exploitable German shale gas deposits to be between 0.7 trillion cubic metres and 2.3 trillion cubic metres. Following a public debate in 2016, the German Legislature prohibited the commercial exploitation of shale gas by unconventional hydraulic fracturing (fracking) in Germany until at least 2021. The law on the ban stipulated that after 2021, the German Parliament (*Bundestag*) could discuss and amend the ban again; however, if the German Legislature does not act, the ban would remain in place, which was the case. During the ban, only four test drillings were permitted if the affected federal states agreed to the exploration. However, according to an evaluation report of the BMWK from 2021, no drillings took place.[43]

Regulatory authorities

The Energy Act assigned the task of regulating Germany's gas markets to the Federal Network Agency (*Bundesnetzagentur*) ("BNetzA"). The responsibilities of the BNetzA therefore include ensuring non-discriminatory third-party access to networks and policing the use-of-system charges levied by market players.

Legal framework

In the gas market, EnWG establishes the applicable legal and regulatory framework. The Ordinance on Access to the Gas Network (*Gasnetzzugangsverordnung*) ("GasNZV") and the Ordinance on the Gas Network Access Fees (*Gasnetzentgeltverordnung*) ("GasNEV") supplement EnWG and are of particular relevance to the gas sector.

The Gas Emergency Plan (*Notfallplan Gas*), the Gas Storage Act (*Gasspeichergesetz)* and the Energy Security Act (*Energiesicherungsgesetzes*) have become more relevant in the context of Russia's invasion of Ukraine.

On 18 August 2022, the Federal Government announced the decision to lower the value tax from 19% to 7% on gas to relieve consumers (implemented on 29 September 2022). A discussed complete abolition was impossible due to European law.[44]

In scope of the Gas Price Adjustment Ordinance *(Gaspreisanpassungsverordnung)* introduced based on Section 26 of the Energy Security Act, a gas levy of 2.419cents/kWh will be introduced in October 2022, allowing gas importers to pass on additional costs to their customers. In this context, importers can only register 90% of their costs from replacement procurement due to lost Russian gas supplies for the levy.[45] However, two days before implementation, the Federal Government announced the end of the gas levy on the night of 29 September 2022 due to major political disagreements in the Ampel coalition.[46] This was due to constitutional concerns regarding the legality of the gas levy and that the actual purpose (to save Uniper) had become obsolete due to the takeover of around 99% of Uniper's capital shares by the Federal Government, as announced on 21 September 2022.[47]

With the end of the gas levy, a new measure was announced on 29 September 2022; a €200 billion package for measures against high energy prices.[48] Although some measures like the gas price brake, the reduction of the sales tax on gas from the current 19% to 7% until spring 2024 and a so called 'defence shield' are already known, the exact implementation and further measures remain to be clarified.[49] In addition, there is great uncertainty at the EU level as to whether the German €200 billion package is politically and legally sound.[50]

On 29 July 2022, fill levels of gas were again increased by ministerial decree based on the Gas Storage Act. Storage facilities must now be filled by 80% on 1 October 2022, 90% by 1 November 2022 and 40% by 1 February 2023. Trading Hub Europe GmbH will be required to gradually fill the gas storage facilities.[51]

The law includes various monitoring and sanctioning mechanisms, such as the withdrawal of capacities in the event of non-use ("use-it-or-lose-it").[52]

Amendments to the Energy Industry Act (*Energiewirtschaftsgesetz*) (EnWG) create precautionary measures in case of a gas shortage. Section 50a Paragraph 1 EnWG contains an ordinance authorisation that allows the Federal Government to react in crisis. Measures include the commissioning of oil and coal-fired power plants on call at short notice. In addition to that, power generation from gas-fired power plants can be limited.[53]

Part of an independent national gas supply is the purchase of liquefied natural gas ("LNG") and the expansion of LNG infrastructure in Germany. With the Act to Accelerate the Use of Liquefied Natural Gas *(LNG-Beschleunigungsgesetz)*, LNG approval procedures and the awarding of public contracts and concessions should be completed more quickly than possible under current legislation.[54]

According to the BNetzA, by the end of 2022 two floating LNG terminals will begin operating, creating an estimated capacity of 13 billion cubic metres ("bcm") of gas by 2023.[55] On 15 September 2022, the BKartA declared that there are no competition concerns about the planned cooperation between Uniper, RWE and EnBW/VNG on that matter.[56]

The latest amends of the EnSiG, introduced in September 2022, intend to further reduce gas consumption by increasing the generation of electricity from renewable energies.[57]

Contractual features

The legal aspects of connection to the German gas networks are governed by network connection agreements (*Netzanschlussverträge*). Under EnWG, it is compulsory for network operators to conclude nationwide cooperation agreements in respect of gas transportation and separate transportation agreements must also be concluded between network operators and shippers. There is an entry and exit scheme in Germany and balancing agreements (*Bilanzkreisvertrage*) must be in place alongside each entry (*Einspeiseverträge*) and exit (*Ausspeiseverträge*) contract. In addition to these regulatory requirements, there is a plethora of gas sale and purchase contracts that govern the legal relationship between generators, importers, traders and consumers.

Unbundling

Germany has notified the Commission that the Third Gas Directive has been fully transposed. All three unbundling models set out in the TEP have been transposed into German law. The German TSOs have opted for different unbundling models, ie some for the FOU and some for the ITO model. According to the Monitoring Report 2021, there were 16 TSOs in 2021, a number which has stayed stable since 2016. There were 703 DSOs in 2021, down from 715 in 2016.[58] Regarding the procedure of certification and unbundling, the electricity and gas sectors are analogous.

Price control

Under the GWB, it is prohibited for an energy utility company to use its dominant position in the market to increase energy prices. On 30 April 2012, BKartA published a report on the effects of grid access tariffs on the competitive market for end customers. According to BKartA, the survey demonstrates that excessive access tariffs led to a lower number of household customers switching to other gas suppliers. The survey reviewed about 7,500 gas access contracts at the distribution network level in Germany.[59] BKartA has initiated proceedings related to market abuse against various suppliers for allegedly applying excessive access tariffs. On 6 November 2012, the Federal Court of Justice confirmed a BKartA test case decision of 16 September 2009, which held that local gas suppliers were not permitted to charge new, and 'unwelcome', competitors 'abusively' excessive access fees.[60]

Implementation of Third Gas Directive

Germany has notified the Commission that the Third Gas Directive has been fully transposed.

B.2 Third party access regime to gas transportation networks

Network connection

Germany has a pipeline network with a total length of about 554,400km for the transportation and distribution of natural gas. This pipeline is integrated into the European network. A substantial part of the infrastructure is the underground storage facilities, which have a maximum available capacity of about 274.72TWh.[61]

On 10 July 2020, BNetzA opened a consultation on the Gas Network Development Plan 2020-2030.[62] This plan, put together by the TSOs, focusses on key aspects of growth for the gas network in Germany such as uninterrupted supply, increased storage capacity and the development of gas power plants within the next ten years. The Gas Network Development Plan 2020-2030 comprises a total of 215 measures with an investment volume of about €8.5 billion. The additional proposed measures are largely related to the planned LNG terminals, the expansion measures necessary to green gases, the supply in Baden-Wurttemberg and the security of supply in the Netherlands, Switzerland and Italy.

Network access

In Germany, non-discriminatory network access is set out in EnWG, which is supplemented by the provisions of GasNZV. Capacity is allocated through the established priority system and an auction process (particularly when physical congestion occurs).

B.3 LNG terminals and gas storage facilities

Germany has the largest gas storage capacity in the EU (24bcm), something the German Parliament sought to maximise by passing legislation in March 2022 to force gas infrastructure operators to fill storage facilities to certain levels throughout the year in order to avoid shortages during winter months.[63] EnWG sets out the details in respect of third-party access to LNG terminals and storage facilities. Third party access to storage facilities is not subject to the same strict regulations as third-party access to the gas transportation network, and it is necessary to negotiate access to storage facilities.

B.4 Tariff regulation

Gas suppliers are responsible for their tariffs. There is no gas tariff regulation, eg fixed prices or maximum permissible revenues of the suppliers. The EnWG sets out certain specifications regarding the form and permissible content of gas invoices.[64]

B.5 Market entry

There are no particular barriers to entry to the gas market in Germany; however, most of the gas market remains vertically integrated, and the upstream sections of the market remain saturated by a limited number of key players. The ongoing liberalisation of the German gas market has however created a more dynamic environment.

The licensing regime

The Federal Mining Act (*Bundesberggesetz*) requires entities to have a licence in order to mine, explore and produce gas and/or oil in Germany. Separate from the requirements under the Federal Mining Act, German public law also requires certain licences to be in place.

EnWG sets out a licensing structure whereby permission to operate gas networks in Germany is given by way of a licence. Under EnWG, a licence will only be approved if the applicant operator has the required personnel, the appropriate technical and economic capabilities, and is considered sufficiently reliable to operate the network in accordance with all legal requirements. It is not necessary for wholesale suppliers to have a permit but any company that supplies electricity to households must provide notification to the relevant responsible authority.

EnWG requires TSOs' corporate structures to be in line with any unbundling requirements. The certification procedure involves approval from both BNetzA and the Commission. On 10 July 2012, as part of the procedure for the certification of TSOs, BNetzA sent the first draft of its decisions to the Commission. The draft decisions, in relation to the gas sector, referred to: bayernets GmbH; Fluxys TENP GmbH; GRTgaz Deutschland GmbH; jordgas Transport GmbH; Nowega GmbH; and terranets bw GmbH. Following comments received from the Commission, BNetzA officially certified these TSOs on 9 November 2012. In total, 16 TSOs have been certified in the gas sector.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Article 3 of the Third Gas Directive sets out the requirements for EU Member States in respect to PSOs, which Germany has partially transposed, including the introduction of a 'supplier of last resort'. Under EnWG, the basic supplier (*Grundversorger*) for a particular region is the gas supply company which supplies the largest number of customers. The basic supplier must offer standard terms and tariffs to all households that have not specifically selected an alternative supplier.

Smart metering

The introduction of intelligent metering systems initially only affects meters for electricity consumption. However, there are already legal requirements for gas meters and their digital connection. As a rule, new gas meters may only be installed if they meet the technical requirements to be connected to a smart meter gateway in the future.

B.7 Cross-border interconnectors

In November 2011, the first arm of the Nord Stream interconnector came online, with the second arm following in October 2012. Nord Stream has the capacity to bring a total of 55bcm per year of Russian gas to Germany. In 2016, 80% of this maximum capacity was utilised, which means an actual gas flow of 43.8bcm. The construction of another pipeline, Nord Stream 2, began in 2018 and was completed in September 2021. Following the Russian invasion of Ukraine, however, certification was put on hold in February 2022 as part of the sanctions measures against Russia and operation has yet to commence.[65] Given the current political climate, the future of the project remains highly uncertain. This situation is aggravated by the leaks in the Nord Stream pipelines discovered at the end of September. At the time of writing, there is still an ongoing investigation; evidence is being secured, and data on the environmental, climate and economic impact is being analysed. Germany and the EU have not yet announced any repair measures or consequences resulting from the suspected sabotage.[66]

Although it is understood that capacity for flows with Austria is more fluid, there are still bottlenecks and a lack of interconnectivity at the borders with Denmark (Ellund) and Poland (Lasow), within southern Germany, and on the north-south route.

Under Article 36 of the Third Gas Directive, an operator of exempt infrastructure does not have to observe the restrictions relating to third party access or regulated tariffs. EnWG provides that Germany's gas interconnectors as well as LNG and gas storage facilities may be exempt from regulation. The OPAL pipeline, co-owned by W & G Transport Holding GmbH and Lubmin-Brandov-Gastransport GmbH, is 470km long and runs from the Baltic coast (linking to the Nord Stream pipeline) to the Czech and German border and the Czech gas network. This pipeline, which has an annual capacity of more than 35bcm and came online in the summer of 2011,[67] is partially exempt from the legislative restrictions relating to third party access. A second important pipeline in Germany is the NEL pipeline (*Die Nordeuropäische Erdgasleitung*) which runs west from the Baltic coast (also linked to the Nord Stream pipeline) to Lower Saxony connecting to western Europe with a capacity of 20bcm per year.[68]

In 2019, the European Parliament decided that both internal EU gas pipelines and those from non-EU countries are now covered by EU law, including competition rules. All future gas pipelines from non-EU countries, including Nord Stream 2, to the extent that it goes ahead, must abide by EU rules, eg that the Gas Directive will be applied to the project.[69]

C. Energy trading

C.1 Electricity trading

Wholesale trading of electricity is carried out on the power exchanges and through over-the-counter ("OTC") bilateral trading. On the power exchanges, a distinction is made between the futures market and the spot market. The futures market takes place on the EEX in Leipzig and the spot market on the European Power Exchange Spot ("EPEX SPOT") in Paris. The futures market in Leipzig offers long term commitments (up to several years) while the spot market in Paris offers day-ahead and intraday trading. Both are part of the EEX Group which has developed into continental Europe's biggest electricity platform in terms of both participants and volume. Furthermore, the EU Emissions Trading System ("EU ETS") takes place on the EEX (see section D.2). However, OTC bilateral trading remains the main way (about 75% of electricity trading) that electricity is traded in Germany. Long-term electricity contracts remain popular in Germany and German OTC contracts tend to have a term of two to three years.

The EEX requires its participants to fulfil certain criteria for admission to its exchange. Therefore, in addition to other requirements such as equity capital of €50,000 and proof of the personal and professional reliability of the managing director, admission to the power exchange requires registration as a trading participant by the European Commodity Clearing AG (ECC). Bilateral OTC platforms also have licensing requirements, but the requirements can be avoided using a broker. Although each contract is agreed individually, almost all contracts are processed via the standard contract developed by the European Federation of Energy Traders (EFET).

The average wholesale electricity price on the EPEX SPOT day-ahead market increased significantly in 2021 to €85.31/MWh (up from €29.26/MWh in 2020).[70] In March 2022, the price rose to a base average of €252.01/MWh.[71] In August 2022, the price more than doubled, leaving it at a base average of €556.14/MWh.

According to figures published by the EEX Group in 2021, the EEX Group increased its global power trading volume to 7,405.7TWh compared to 4,962TWh in 2018. A total of 3,097.6TWh was from German power futures (one of EEX Groups largest markets) and a total of 629.5TWh was traded on the EPEX SPOT in Paris.[72]

PPAs are another type of bilateral trade. In contrast to the classic OTC business, a PPA is intended to create a more long-term commitment (up to 20 years) and the contracts are drafted more individually to meet the needs of the parties involved. Its main field of application is in the marketing of post-EEG plants (the EEG subsidy normally expires after 20 years, see section D.4) where the electricity generator directly sells to the end consumer (usually big companies). The advantage of this type of contract for the plant operator is long-term financial planning security for their renewable energy plant, while the customer is supplied with green electricity on a permanent basis. In addition, the electricity generator and end consumer do not need a middleman, ie an exchange, platform or broker.

Following a decision by BNetzA, TSOs also organise online auctions for balancing electricity products (*Regelleistungsmarkt*).[73]

C.2 Gas trading

Previously, natural gas imports in Germany were mainly supplied on the basis of long-term contracts between suppliers and a number of importers in Germany.

Against the backdrop of profound changes in the market (the increasing importance of more liquid trading markets, a divergence of prices at European trading points and oil import prices) the challenge was to adapt the pricing mechanisms contained in long-term import contracts to the changing market and competitive conditions, and to maintain them as an instrument for long-term sustainable procurement policy.

The German gas market currently operates with two different types of gas (the low-calorific gas ("L-gas") and high-calorific gas ("H-gas") networks operate separately for technical reasons). Since June 2019, it is envisaged that the German gas network will be completely converted to H-gas by 2030, with all customers encompassed in one larger balancing area. In 2009 and 2010, two antitrust decisions by the Commission addressed the problem of insufficient access to transport capacity in Germany. The Commission's intervention led RWE to divest its gas transportation network and E.ON to release significant volumes at the entry points to its gas networks. However, Following the Commission's decision, E.ON booked significantly less capacity than the threshold set in the decision. This allowed new competitors to enter the market and gain significant market share. At E.ON's request, the Commission reassessed the market situation in July 2016 and concluded that, as a result of this fundamental structural change in the German gas market, the commitments were no longer necessary and therefore lifted them.[74]

German legislation on capacity allocation and congestion management is intended to improve the situation, particularly by increasing the use of capacity auctions on a centralised booking platform. Previously the German gas market area featured two trading hubs, Gaspool and NetConnect Germany (NCG). These hubs merged on 1 October 2021 into a single Germany-wide gas market area called Trading Hub Europe. This merger has facilitated the easy transportation of gas throughout Germany; however, the operation remains subject to the same restrictions on capacity as before. In its first five months of operation, Trading Hub Europe averaged a total trading volume of 324,829GWh per month.[75]

The average day-ahead natural gas price on the EEX energy exchange in November 2021 was €80.81/MWh for the Trading Hub Europe market area.[76]

In the six months following the launch of the Trading Hub Europe, the average combined churn rate for H-Gas and L-Gas was 3.07% .[77] These churn rates appear to be falling slightly, suggesting that there is room for increased liquidity in the market overall.[78]

D. Nuclear energy

For the latter part of the 20th century, and continuing into the 21st century, the German approach to nuclear energy has become entangled in politics. Consequently, Federal Government policy has been inconsistent. In the wake of the tragedy at Fukushima in 2011, Germany decided in June 2011 that nuclear power should be phased out of the German energy mix. The 13th Act Amending the Atomic Energy Act (*13. Gesetz zur Änderung des Atomgesetzes*) stipulates that the last nuclear plant will be shut down by the end of 2022.

At the time of writing, three nuclear plants remain active and are planned to be shut down by the end of 2022.[79] There are also concerns about energy supply security and the future of the three remaining nuclear plants after Russia threatened to halt gas supplies to Germany. In this context, it is relevant to note that the Green Party, which emerged from an anti-nuclear movement, is currently in government. A 'stress test' initiated by the Federal Government in July 2022, determined that security of supply is ensured under tightened conditions. However, to safeguard against emergencies in winter 2022, an emergency reserve of two nuclear power plants in south Germany will exist until mid-2023. Otherwise, the targets for the nuclear phase-out at the end of 2022 will be adhered to.[80]

On 27 September 2022, Robert Habeck, the Economics Minister (Green Party) announced that the reserve option will be used and that the Isar 2 and Neckarwestheim nuclear power plants will remain on the grid in the first quarter of 2023.[81] However, at the time of writing, the Atomic Energy Act has not yet been amended respectively. It is assumed that this will be implemented in November 2022. Therefore, by law, the nuclear phase-out is (still) set for the end of 2022. The governing coalition partners of the Green Party, the Social Democrats and the Liberal Democrats prefer an even longer nuclear term. It is assumed that there will be regular changes (back and forth) in the coming months.

The four operators of nuclear facilities in Germany (RWE, E. ON/Uniper, Vattenfall and EnBW) brought a compensation claim for the costs associated with this rapid reversal in German energy policy, which resulted in a combined pay-out of €2.5 billion.[82] The claims related, in particular, to costs associated with upgrade works, appropriate write downs and decommissioning costs that needed to be brought forward.[83]

The search for a final nuclear repository for the highly radioactive nuclear waste from nuclear power plants in Germany is also unresolved. In September 2020, the interim report on nuclear repositories was published, presenting 90 subareas that would in principle be suitable as nuclear waste repositories in Germany.[84]

E. Upstream

Germany produced about 5% of its gas consumption domestically in 2021 (5.2bcm), with net imports accounting for the remainder.[85] Natural gas imports in 2021 amounted to about 5,000,000TJ, with the main sources of gas imports being Russia and Norway.[86] Gas imports mainly arrive via pipelines. The price of gas imports in 2021 amounted to an average of about €7,000/TJ (about €25,440,000/TWh). In 2022 (last update April 2022), the price rose to an average of about €15,000/TJ (about €54,000,000/TWh). To give a comparison, the prices were at about €3,400/TJ in 2020 and at about €4300/TJ in 2019.[87]

There are some limited upstream oil and gas activities in Germany. According to figures published by the Federal Association for Natural Gas, Oil and Geoenergy (*Bundesverband Erdgas, Erdöl und Geoenergie e.V.*), the decline of natural gas production has continued. Although in 2021 the domestic gas production was at about 5.2bcm, the amount at the beginning of the millennium was four times as large.[88] Due to the depletion of gas fields and ongoing maintenance work at the natural gas processing plant in Grossenkneten, the 15.1% fall in annual natural gas production in 2020 was more pronounced compared to previous years and amounted to 5.6bcm. In contrast, annual oil production was almost stable. Compared to 2019, production dropped by 1.4% and amounted to less than 1.9 million metric tonnes (including gas condensate).[89]

By 1 January 2021, Germany's estimated safe and probable natural gas reserves amounted to 43.2bcm (Vn) of crude gas. As a result, reserves declined by 3.4bcm (Vn).[90] Since the BNetzA declared the alert level (*Alarmstufe*) of the Gas Emergency Plan (*Notfallplan Gas*) on 23 June 2022, it has been providing regular updates on the filling levels of gas storage facilities in Germany. On 1 July 2022, the fill level was 61%.[91] On 16 August 2022, the fill level was 76.79%. The 'Gas Emergency Plan for the Federal Republic of Germany' is based on the so-called European SoS Regulation, ie Regulation (EU) 2017/1938 of the European Parliament and of the Council of 25 October 2017 concerning measures to safeguard security of gas supply. The emergency plan has three escalation levels (early warning level, alert level, and emergency level), depending on how significant the state's measures are. After the declared second stage (alert level), a nationwide gas distribution by the Federal Government (through the BNetzA) is the final and third stage and the market will be lifted out. At the time of the alert level, Nord Stream I gas flows were only at 40% and were scheduled to be completely shut down for maintenance from 11 to 21 July 2022.[92] After maintenance, Nord Stream I gas flows had been further reduced to 20% of the maximum capacity and ultimately to 0%.[93] At the time of writing, they remain at 0%. According to the BNetzA, this would mean that the legal requirement of having the fill levels at 90% in November 2022 would not be achievable.[94]

Most German gas deposits can be found onshore in the federal state of Lower Saxony, but production conditions are difficult as the gas deposits are located about 3,000 metres to 5,000 metres below the surface.

BEB Erdgas und Erdöl GmbH, a subsidiary of ExxonMobil and Shell, is the biggest gas producer in Germany, producing 41% of natural gas in 2021.[95] Its main areas of production are situated in the districts of Rotenburg/Wümme (*Söhlingen*), Nienburg/Weser (*Flecken Steyerberg*) and Oldenburg (*Hengstlage*) (all in Lower Saxony).

Framework

The overall legal framework for upstream activities is set out in the Federal Mining Act of 13 August 1980 (*Bundesberggesetz*) ("BBergG"). This is supplemented by the Law on the Harmonisation of the Legal Situation Regarding Natural Resources of 15 April 1996 (*Gesetz zur Vereinheitlichung der Rechtsverhältnisse bei Bodenschätzen vom 15 April 1996*) and the Regulation Regarding the Environmental Impact Assessment of Mining Projects of 13 July 1990 (*Verordnung* über *die Umweltverträglichkeitsprüfung bergbaulicher Vorhaben (UVP-V Bergbau) vom 13. Juli 1990*).

The licensing of upstream activities is a matter for German Federal state governments. According to the BBergG, there are two relevant types of licences for upstream hydrocarbon activities, ie exploration licences (*Erlaubnis*) and production licences (*Bewilligung*). Given that the vast majority of oil and gas production takes place in the federal states of Lower Saxony (about 97% of German gas production), most licences are issued by the state authority for mining, energy and geology (*Landesamt fur Bergbau, Energie und Geologie*) in Hanover, the state capital of Lower Saxony.

Interested parties can apply for a licence at any time as there are no specific licensing rounds. It is necessary to submit a detailed work plan and evidence of financial resources together with the relevant application.

Exploration licences are granted for five-year periods, which can be extended by three years, whereas production licences are generally granted for such period as is requested by the relevant applicant (up to a maximum of 50 years) taking into consideration the technical and economic conditions of a particular field. Exploration licences will be withdrawn if the relevant work programme is not commenced within a year of the relevant licence being granted or if the production is interrupted for more than one year. Regarding production licences, a three-year period applies regarding the obligation to commence or continue the production.

Royalties

Federal state governments may set royalties of up to 40% based on the market value of the relevant production for production licences (*Förderabgabe*) or up to €100/km² for exploration licences (*Feldesabgabe*). As of 2021, the applicable royalty rate for the Förderabgabe in Lower Saxony has been capped at 5% by the State Parliament in Hannover, following legal action brought by several companies in Lower Saxony.[96] This is a significant reduction compared to previous rates which were on average 13% for natural gas in 2017, amounting to a total of €189 million paid to the state.[97]

F. Renewable energy

F.1 Renewable energy

The German renewable energy law is founded on the EEG. The EEG is intended to:

"enable a sustainable development of energy supply, in particular in the interest of climate and environmental protection, to reduce the economic costs of energy supply also by including long-term external effects, to conserve fossil energy resources and to promote the further development of technologies for the generation of electricity from renewable energies" (Section 1 Paragraph 1 EEG).

This overall goal is accompanied by milestones that stipulate what percentage of renewable energy is to be achieved at what point in time.

The EEG is supplemented by the Ordinance on the Implementation of the Renewable Energies Act and the WindSeeG (*Verordnung zur Durchführung des Erneuerbare-Energien-Gesetzes und des Windenergie-auf-See-Gesetzes*) („EEV"), the Act for the Development and Promotion of Offshore Wind Energy (*Gesetz zur Entwicklung und Förderung der Windenergie auf See*) („WindSeeG") and the Act on the Saving of Energy and the Use of Renewable Energies for Heating and Cooling in Buildings (*Gesetz zur Einsparung von Energie und zur Nutzung erneuerbarer Energien zur Wärme- und Kälteerzeugung in Gebäuden*) („GEG").

The EEG is subject to two major legislative changes. One is the transition from the EEG 2017 to the EEG 2021, and the other is the so-called 'Easter package'. The amendment to introduce the EEG 2021 was implemented at the end of 2020 with the Act Amending the Renewable Energy Sources Act and Other Energy Regulations (*Gesetz zur Änderung des Erneuerbare-Energien-Gesetzes und weiterer energierechtlicher Vorschriften*) and came into force on 1 January 2021.

The Easter package was introduced on 6 April 2022 and contains three draft bills of the Federal Government . One of the three draft bills, the draft bill on immediate measures for accelerated expansion of renewable energies and further measures in the electricity sector (*Entwurf eines Gesetzes zu Sofortmaßnahmen für einen beschleunigten Ausbau der erneuerbaren Energien und weiteren Maßnahmen im Stromsektor*), aims to amend the EEG and is planned to come into force as the EEG 2023 at the beginning of next year. The first parliamentary debate on the bill was on 12 May 2022 and it was passed by the

German Parliament on 7 July 2022 and by the Federal Council (*Bundesrat*) on 8 July 2022. Please note that the EEG 2023 has not yet been finalised, it will presumably be subject to further legislative changes beyond the Easter package in an ongoing process. Therefore, we have reviewed and revised the changes for the EEG concerning the Easter package separately at the end according to the status of the current situation.

Since the 29 July 2022 and 30 July 2022, two regulations of the EEG 2023 have come into force. Accordingly, the use of renewable energy is now significantly in the public interest and serves public safety. This particularly impacts decisions made by the authorities.[98]

Target and development path

The EEG 2021 aims that before 2050, all electricity generated in Germany will be greenhouse gas ("GHG") neutral. As an intermediate step, a climate neutrality of 65% is to be achieved as early as 2030. These goals are to be achieved through a gradual increase in the expansion of renewable energies. The exact development path (*Ausbaupfad*) of this increase is outlined in the EEG (Section 4 EEG). An increase is planned for onshore wind turbines, offshore wind turbines (in accordance with the WindSeeG), solar plants and biomass plants. For example, the installed capacity of onshore wind energy is expected to increase to 62GW in 2024, 65GW in 2026, 68GW in 2028, and 71GW in 2030 (Section 4 No.1 EEG).

In addition, there is a general electricity quantity path (*Strommengenpfad*) (Section 4a EEG). The electricity quantity path establishes a benchmark that the amount of renewable electricity generated must be 281TWh in 2023, 295TWh in 2024, 350TWh in 2028, and 376TWh in 2029. To secure these goals, the EEG provides for an annual monitoring of target achievement (Section 98 EEG).

Additionally, one goal of the GEG is to cover at least 15% of the heating and cooling energy demand of new buildings through the use of renewable energies (Section 10 GEG). It also stipulates rules for the most economical use of energy in buildings, such as a minimum level of thermal insulation and regulations on leak tightness.

In accordance with the EEG, the tenders for biomass plants take place every year on the bidding dates of 1 March and 1 September. The annual tender volume is 600MW of installed capacity.

Financing system of the EEG

The financing system of the EEG is stipulated in Section 19 EEG. In general, operators of renewable energy plants that generate electricity receive a fixed payment for the generated electricity from the grid operator (Section 19 Paragraph 1 EEG). The amount of the fixed compensation was originally set by the state as a fixed price. However, under the EEG 2017, the fundamental compensation scheme changed from a guaranteed price to a tendering procedure carried out by BNetzA. Therefore, the amount of the compensation is now determined by tenders and bids (Section 22 Paragraph 1 EEG). This led to market-based rather than Federal Government-determined funding, with enhanced competition between generators.

There are three options for the operators of renewable energy plants to receive EEG funding. The most common is the so-called market premium (*Marktprämie*). The operators of renewable energy plants can directly sell the generated electricity and the grid operator pays the plant operator an additional market premium (Section 20 EEG). The amount of the respective market premium is the difference to be calculated between the fixed compensation for energy determined in a tender procedure as mentioned above and the average stock exchange price for electricity determined on a monthly basis (Section 23a EEG in connection with Appendix 1 of the EEG).

Alternatively, the operators of renewable energy plants (under certain restrictions, eg plants with an installed capacity of up to 100kW) can feed the generated electricity into the grid without selling it themselves. To do this, the grid operator pays the operator of the plant the compensation determined by the bidding procedure (*Einspeisevergütung*). The grid operator sells the electricity fed into the grid on the electricity stock exchange. Since the prices achieved on the exchange are usually lower than the compensation rates set by the tender procedure, the grid operator is reimbursed for the difference.

A third method, which is rarely used, involves the landlord getting EEG subsidies if they sell electricity directly to the tenants in the respective building (Section 21 Paragraph 3 EEG).

EEG levy

This expansion of renewable energies in Germany has been financed by the EEG levy for about 20 years. The EEG levy is paid by the end consumer and is then used to finance EEG projects. While the EEG levy was still 0.4cents/kWh in 2003, it has steadily increased over the years to 1.3cents/kWh in 2009. The levy jumped to 3.59cents/kWh in 2012 and 6.24cents/kWh in 2014. Between 2014 and 2021, the EEG levy was between 6 and 7cents/kWh without changing significantly. In 2022, the EEG levy fell back to 3.7cents/kWh.

From 1 July 2022, electricity consumers in Germany no longer have to pay the EEG levy (Act to reduce the cost burdens of the EEG surcharge and to pass on this reduction to end consumers) (*Gesetz zur Absenkung der Kostenbelastungen durch die EEG-Umlage und zur Weitergabe dieser Absenkung an die Letztverbraucher*). From 2023, the EEG levy will be permanently reduced to zero with the EEG 2023.

The loss of revenue resulting from the reduction of the EEG levy to 0cents/kWh is to be reimbursed by the Federal Government and from the 'Energy and Climate Fund'.

Further changes due to the EEG 2021

The implementation of the EEG 2021 has introduced further changes. Among other things, the acceptance of municipalities is to be strengthened by the possibility of financial participation in the expansion of renewable energy (Section 6 EEG). This means that, on a voluntary basis, the plant operator may pay the affected municipalities amounts totalling 0.2cents/kWh for the amount of electricity fed into the grid (Section 6 Paragraph 2 EEG).

The maximum value of subsidies for electricity from onshore wind turbines was 6cents/kWh in 2021, reducing by 2% yearly (Section 36b EEG). At the same time, the so-called southern quota (*Südquote*) for onshore wind turbines was introduced. As a result, bids submitted for onshore wind projects in the southern region will be given preferential treatment, with 15% of the EEG subsidy (20% from 2024) reserved exclusively for these projects (Section 36d EEG).

One change to the EEG 2021 that could not be implemented, due to a violation of subsidy law according to the Commission, is the so-called 'old plant subsidy' (*Altanlagenförderung*). According to Section 25 Paragraph 1 of the EEG, the aforementioned financing systems may only be paid for a period of 20 years. Since the EEG has now been in place for more than 20 years, the first plants are no longer eligible for subsidies. However, plants that are not onshore wind turbines and have an installed capacity of up to 100kW are still eligible until 31 December 2027, even if they are more than 20 years old (Section 25 Paragraph 2 EEG).

Easter package

As described above, the so-called Easter Package is currently the subject of public discussion alongside the EEG 2023. The main amendment of the Easter Package aims to raise the 2030 target of climate neutrality to 80% and achieve near climate neutrality in electricity generation as early as 2035. In line with this, the above-mentioned development paths and electricity quantity paths were increased. Please note in this context that the EEG only aims at climate neutrality in the electricity generation sector and not energy in general.

In addition, to accelerate the expansion of renewable energies, the principle that the use of renewable energies is in the overriding public interest and serves public safety (the most important consideration criteria in public approval procedures under German law) is to be anchored in the EEG.

For the first time, the new law will be consistently geared to achieving the 1.5°C path under the Paris Climate Agreement (*Pariser Klimaschutzabkommen*). The significant expansion of renewable energies is intended to make a major contribution to reducing Germany's dependence on imports of old energy sources.

The Act also helps to provide financial relief for households and companies due to increased energy costs. The EEG levy will not only be permanently reduced to zero from 2023, rather it will be abolished completely. Therefore, the financing requirements for renewable energies will be offset from the Federal Government's special 'Energy and Climate Fund' and the EEG subsidy will be terminated via the electricity price.

In order to achieve the new expansion target for wind and solar energy in 2030, the tender volumes for the period up to 2028/29 will be increased. In addition, the planning and approval procedures are to be accelerated.

The EEG 2023 also provides new impetus to strengthen local acceptance and anchoring of the energy transition. For example, wind and solar projects by citizen energy companies will be exempt from the tendering process and can thus be implemented with less bureaucracy.

In addition, the financial participation of municipalities in wind and solar projects will be further developed.

The Energy Financing Act (*Energiefinanzierungsgesetz*) bundles all energy related levies.

F.2 Renewable pre-qualifications

Based on the EEG and the published application forms of BNetzA, there are essential prequalification that a bid for an auction procedure must address. The procedures for the different energy sources each have their own legal requirements and published application forms. BNetzA will announce the auctions (including application forms and regularly a 'check list') on its website no earlier than eight weeks and no later than five weeks before the respective bidding date for the respective energy sources. It should be noted that the form requirements are very strict. If the bids do not comply with the published application forms on the website, they will be excluded from the auction. There are general requirements for bidding such as providing a security, the form of energy (*Energieträger*), bid quantity in kilowatts and bid value in cents per kilowatt-hour for which the bid is submitted, but also special requirements such as numbers under which the installations have been reported to the register or a file number of the permit and the licensing authority.

F.3 Biofuel

There are three main types of biofuel in Germany: biodiesel, bioethanol and biomethane. The ERS Directive currently sets out the relevant legal framework and this has been transposed by the BImSchG[99] and the Biofuel Sustainability Ordinance (*Biokraftstoff-Nachhaltigkeitsverordnung*).[100] According to the latter, biofuels will only be considered sustainably produced in the future if, considering the entire production and supply chain, they save at least 35% in GHGs compared to fossil fuels. In 2017, they must save more than 50%. Furthermore, no land with high carbon content or high biodiversity may be used to grow crops for biofuel production. Biofuels that do not meet these sustainability standards cannot receive tax breaks or count toward the biofuel quota that must be met. In 2007, the use of biodiesel and plant oil in Germany peaked at 10% of diesel consumption. Since then, there has been a shift to general blending and the level of transport biofuels have generally stabilised about 5-6%.[101]

The use of biofuels in Germany is endorsed through a combination of different policies including mandatory blending requirements, tax benefits and a quota trade system.[102] In implementing the EU Renewable Energy Directive 2018/2001 (RED II), Germany introduced a cap for biofuels from cultivated biomass at 4.4% from 2026[103] as well as a target ban on palm oil in biofuels to be implemented by 2026. In 2020 the latest estimates of generation costs were between €1,374 million and €2,153 million as the production of biofuels is, for the most part, more expensive than that of fossil fuels.[104]

G. Climate change and sustainability

G.1 Climate change initiatives

Climate change is a key issue in Germany, both as a member of the EU and in its own right. According to the latest figures, Germany is the world's sixth largest emitter of GHGs and the largest in the EU.[105] With a target to reduce emissions from 1990 levels by 65% by 2030 and be climate neutral by 2045, climate change is a pressing concern.

In addition, Germany (as a member of the EU) aims to generate 32% of energy from renewable energy sources ("RES") under the Renewable Energy Directive by 2030. This target was raised to 40% of energy generated from RES by 2030 on 27 June

2022 by an agreement of the EU Energy Ministers.[106] This goal is accompanied by Germany's ambition to increase the share of electricity (not energy in general) generated from renewables in gross electricity consumption to 65% (planned raise to 80% according to the Easter package) in 2030.

The most important German framework on climate change is the German Federal Climate Protection Act (*Bundes-Klimaschutzgesetz*) (amended in June 2021),[107] the Coal Termination Act (*Kohleausstiegsgesetz*) and the EEG.

The most recent programmes are the Immediate Act Programme 2022 (*Sofortprogramm 2022*)[108] which has involved €8 billion being set aside to fund climate goals and the Climate Protection Programme 2030 (*Klimaschutzprogramm 2030*)[109] which implemented a National Emission Trading System in Germany (see section D.2).

As of 2021, the International Climate Change Initiative (*Internationale Klimaschutzinitiative*) (which now sits within the BMWK) has invested €5 billion in over 800 projects related to climate change and biodiversity in developing, industrialising and transitioning countries since its inception in 2008.[110] There is also a National Climate Change Initiative (*Nationale Klimaschutzinitiative*), which offers advice and projects to consumers, industries, local authorities and schools. At the time of writing, the National Climate Change Initiative has invested €1.35 billion since 2008.[111]

The German Federal Climate Protection Act was challenged in Germany's Federal Constitutional Court in 2021 by a group of young people (up to 15 years old) who claimed that some provisions of the Climate Change Act are incompatible with the German constitution (*Grundgesetz*). Of the multiple complaints brought by the claimant group, the Court ruled that the national climate targets and annual emission allowances intended in the German Federal Climate Protection Act are incompatible with the German constitution insofar as they irreversibly postpone high emission reduction burdens to periods after 2030 and lack sufficient specifications for further emission reductions from 2031 onwards.[112] The rationale of the German Federal Constitutional Court is that protecting the future freedoms of future generations also requires that the transition to climate neutrality is initiated in a timely manner with a sufficient degree of development pressure and planning certainty. As a result, on 24 June 2021, the German Parliament passed an amended German Federal Climate Protection Act with the targets mentioned above (GHG reduction of 65% instead of 55% by 2030 compared to 1990, and to be climate neutral by 2045 instead of 2050).

The new coalition Federal Government that took over in December 2021 has been a driving force behind tougher climate action in Germany, which has so far involved a pledge of the G7 to become a nucleus of an international climate club under Germany's G7-presidency,[113] and an update to the EEG calling for more ambitious targets (as mentioned above).[114]

Germany continues to work towards phasing out nuclear power from the energy mix in Germany (see section D) by the end of 2022 but plans to reactivate certain coal plants to ensure electricity supply security in response to the Russian threats during its conflict with Ukraine.[115] Germany's climate action, and in particular energy supply, remains a work in progress which is expected to experience significant developments in the upcoming years.

Energy efficiency

Energy efficiency has become an increasingly important topic in Germany. The German Federal Ministry of Economics states that 'the cleanest and cheapest energy is the energy which is not consumed in the first place'. Therefore, the ministry wants to shape the German economy into the world's most energy-efficient economy and halve primary energy consumption by 2050 compared to 2008. On 18 December 2019, the German Federal Ministry of Economics, together with the Federal Government presented the Roadmap Energy Efficiency 2050[116] (*Energieeffizienzstrategie 2050*) to achieve this goal. The roadmap is intended to renew the Federal Government's National Action Plan on Energy Efficiency ("NAPE") from 2014. Among other things, the now so-called 'NAPE 2.0' provides for tax breaks and subsidies for energy-efficient buildings as well as the further development of the energy efficiency networks (*Energieeffizienznetzwerke*) in which companies exchange their successful approaches to increasing energy efficiency. For all support programs in the area of energy efficiency, the German Federal Ministry of Economics will provide an estimated average of about €6 billion per year for the next four years (starting from the end of 2019).

G.2 Emission trading

There are two emission trading systems applicable in Germany. One is the EU ETS (since 2005) and the other is the National Emission Trading System (since 2021) that was introduced as a part of the Climate Protection Programme 2030.

The legislative framework for the EU ETS is set out in the EU ETS Directive and the New EU ETS Directive. These have been transposed into German law through the Federal Greenhouse Gas Emissions Trading Act[117] (*Treibhausgas Emissionshandelsgesetz*) ("TEHG"). The legislative framework for the National Emission Trading System is the Fuel Emissions Trading Act (*Brennstoffemissionshandelsgesetz*) that was introduced in 2019 (amended in 2020) leading to the launch of the National Emission Trading System in Germany on 1 January 2021.

The National Emission Trading System prices CO_2 emissions only in the heating and transport sectors. The CO_2 emissions of heating and transport outside the sectors are covered by the EU ETS. Germany has so far lacked a financial incentive to reduce emissions. Therefore, the systems can coexist without Germany being bound to the EU ETS for these specific sectors.

In contrast to EU ETS, the National Emission Trading System is not a downstream emission trade but an upstream emission trade. That means the National Emission Trading System does not start where emissions are generated, eg in industry, in power plants or in aviation, but it obliges the distributors who sell fuel to the end consumer (who then generates emissions) to purchase pollution rights in the form of certificates. Therefore, the fuel distributor has to pay for the subsequent and anticipated burning of the fuels by the end consumer. This approach means that fewer parties (eg not every driver with an internal combustion engine) have to participate in emission trading and the fuel distributors pass on the additional costs to the end consumers.

The German Emissions Trading Authority (DEHSt) at the Federal Environment Agency is responsible for implementing the national emission trading scheme.

G.3 Carbon pricing

The aforementioned National Emission Trading System is launched with a fixed price phase that starts at €25/tonne of CO_2 in 2021 and increases by €5/tonne of CO_2 until 2026 in order to provide planning security. However, from 2026 onwards the CO_2 price will be shaped by market demand within a predefined range from €55 between €65 tonne of CO_2.[118] As of 2022, the price is €30/tonne of CO_2.

G.4 Capacity markets

In 2015, the BMWK declared itself in favour of the further development of the electricity market and against a capacity market.[119]

H. Energy transition

H.1 Overview

In Germany, the energy transition (*Energiewende*) is closely linked to measures against climate change and carbon reduction (see section G). Briefly summarised, Germany's main target is to reduce emissions from 1990 levels by 65% by 2030 and to be climate neutral by 2045.

H.2 Renewable fuels

Hydrogen

The Federal Government adopted a hydrogen strategy (*Nationale Wasserstoffstrategie*) ("NWS") in June 2020. The NWS envisages investments of a total amount of €9 billion for the promotion of hydrogen technologies and the development of international partnerships, focusing on the transport sector and energy-intensive industry to reduce carbon dioxide emissions.[120]

In the first phase of the NWS (until 2023), further research and the market ramp-up of hydrogen technologies are the key objective.

To implement the strategy, the Federal Government, among other things, selected 62 hydrogen projects to receive government funding in May 2021, of which four had been approved by the Commission.[121] In October 2022, the Commission approved two important projects by BASF and the city of Salzgitter, aiming at a CO_2 reduction of 2.5 million tonnes a year.[122]

Apart from important amendments made in the EnWG promoting a gradual development of hydrogen infrastructure in Germany, several uncertainties remain regarding production and transport of hydrogen in Germany. Currently Germany is relying on international cooperation as part of its national hydrogen strategy, eg from Africa and the UAE.[123]

In addition, recent developments for green hydrogen show the implementation of the NWS in the form of a "Canada-Germany Hydrogen Alliance"[124] transporting green hydrogen stored as ammonia from Canada to Germany as well as the announcement of governmental funding for research projects in the field of electrochemical materials and processes for green hydrogen and green chemistry.[125]

With H2 Global, a new tender procedure has been approved, ramping up the market on an industrial level by matching supply with the demand. The difference between supply prices (generation and transport) and demand prices is compensated by grants from the Federal Government within the framework of a mechanism based on the Contracts for Difference (CfD) approach. The procedure was approved by the Commission in December 2021.[126]

Until 2030, hydrogen production plants with a total capacity of up to 5GW will be built. By 2035, or 2040 at the latest, 10GW should be installed while the Government expects that about 90TWh to 110TWh of hydrogen will be needed in Germany by 2030.[127]

Ammonia

Germany is the largest consumer of ammonia in Europe. In Germany, six ammonia plants are operated at four locations.[128] Ammonia is currently sourced solely with the use of gas, making up for 11%of the industrial use of gas in Germany while producing roughly six million tonnes of CO_2 emissions.[129]

H.3 Carbon capture and storage

The use of carbon capture and storage ("CCS") systems in Germany is not widespread and currently legally unfeasible. Originally, Germany implemented the Act on the Demonstration and Use of the Technology for the Capture, Transport and Permanent Storage of CO_2 (*Gesetz zur Demonstration und Anwendung von Technologien zur Abscheidung, zum Transport und zur dauerhaften Speicherung von Kohlendioxid*) ("KSpG") for the transposition of the CCS Directive into national law on 24 August 2012. The KSpG allowed the annual storage of CO_2 for a single installation that is not more than 1.3 million tonnes if the annual total capacity in Germany is not already more than 4 million tonnes; however, no application was submitted and the deadline for an application expired at the end of 2016. Therefore, even though CCS solutions are currently being re-discussed, Germany will first need a legally secure basis in order to implement these projects. In April 2021, the Federation of German Industries (*Bundesverband der Deutschen Industrie*) (BDI) published a paper on the role of CCS in meeting climate targets,[130] although this subject has not featured heavily in recent climate debate.

H.4 Oil and gas platform electrification

As Germany produces very little gas and oil, the electrification of oil and gas platforms is currently not relevant.

H.5 Industrial hub

According to the Federal Statistical Office, German industrial hubs require more than a quarter of the total amount of energy used in Germany.[131] Looking at the different industries, it can be observed that the production of chemical products requires the most energy. Metal production and processing also require large amounts of energy. In addition, there is a high energy demand in coking and mineral oil processing, as well as in the production of glass, glassware, ceramics, paper and cardboard.[132] Besides the shortage of materials, reliable and emission-free energy supply is the most important issue for these industries in the coming decades. The joint Industry 4.0 platform of the BMWK and the Ministry of Education and Research intend to make a contribution to fulfilling these tasks.[133] Nonetheless, this is only one aspect of Germany's overall policy, which generally focuses on a sustainable German industry.

H.6 Smart cities

Regarding the concept of Smart Cities, the German Federal Ministry of the Interior and Community ("BMI") promotes a Smart City Dialogue that includes various activities in terms of the digital transformation of cities and municipalities. It contains the establishment of a national and international dialogue platform to assess potential risks and opportunities arising in the context of Smart Cities, as well as the funding of model projects on a federal and EU level.[134]

On 15 July 2021, the BMI announced 28 cities as participants in the third round of the "Model Project Smart Cities", a project to support communities with the development and implementation of digital strategies. The project provides subsidies amounting to €300 million.[135]

I. Environmental, social and governance (ESG)

Decarbonisation is the biggest ESG issue in Germany's energy policy (as mentioned above, in sections G. and F.). However, while phasing out energy from nuclear and coal, Germany is still heavily dependent on gas. This dependence has been reduced by German measures due to the conflict in Ukraine and Russia's gas supply stop, although it is still present. Therefore, the EU taxonomy is an important topic for Germany to classify its own energy policy as sustainable.

To meet the EU's climate and energy targets for 2030 and the green deal, the EU established a taxonomy classification system with a list of environmentally sustainable economic activities.[136] Under this taxonomy, both gas and nuclear energy are still considered sustainable under certain circumstances. In a reply from the BMWK to the EU on the criticisms of the EU taxonomy, Germany welcomed a transitional green classification of gas, but clearly rejected nuclear energy. According to the BMWK, in view of the ambitious climate targets, it is important to push ahead with the phase-out of all fossil fuels. For this reason, in the view of the Federal Government, the use of natural gas is not sustainable in the long term. The decisive factor for classification as a transition technology is that the gas-fired power plants support the rapid switch to renewable energies and complement, rather than displace, renewable energies by being "Hydrogen-Ready" (*Wasserstoff-Ready*).[137]

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Energy law in Greece

Recent developments in the Greek energy market

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Promoting the energy sector

Greece has a liberalised energy market that has evolved into an energy hub during the last decade and represents an important sector of the Greek economy. Notwithstanding the adverse impact of the recent financial crisis and the COVID-19 pandemic on the Greek economy. The conclusion of electricity and natural gas agreements with major European, American, and Asian companies has positioned Greece as a significant figure in Europe. Several energy projects of great geopolitical significance, with the engagement of global economic players, are currently being implemented.

The Greek Government ("Government") is continuing its efforts to reform the Greek economy, establish a commercial mindset in the energy markets, and provide a wider range of innovative investment tools to investors. The Government is also stepping-up its drive for promoting the energy transition via robust renewable energy sources ("RES") development and through initiatives which will enable the advancement of innovative technologies in the energy sector.

Greece undertook a fundamental restructuring of its electricity market in accordance with the rules for market integration, based on the European Target Model for electricity. In that context, the Target Model Law, which entered into force as of November 2020, introduced the general framework of the new operating model of the wholesale electricity market ("Target Model"), consisting of a day-ahead market, an intraday market, the imbalances market, and the energy derivatives market (financial instruments and products), while the pertinent market rulebooks allowed for its implementation.

In March 2020, the Regulatory Authority for Energy ("RAE") approved the operation of the Hellenic Energy Exchange SA ("HEnEx"), established in 2018, for the management and operation of the day-ahead market and intraday market. The former market operator (LAGIE), following the assignment of all activities that were relevant to the operation and the management of the former day-ahead scheduling to HEnEx, was renamed 'Operator of RES and Guarantees of Origin SA' and is responsible for the operation of RES and Guarantees of Origin ("GOs").

The Target Model Law establishes a significant expansion of the available electricity trading mechanisms by introducing the energy financial instruments and products provisioned in MiFID II (cases 5-11 of Annex 1). It is now institutionally possible for such contracts to appear in the Greek energy market. The Target Model Law further allows for the conclusion of bilateral agreements with physical delivery of electricity along with cash (economic) settlements. Transactions over such energy financial instruments and products can now be concluded outside the HEnEx market and directly between counterparties.

Greece took the first step towards the effective integration of its day-ahead market in the EU Target Model on 15 December 2020, with the day-ahead market coupling of Greece and Italy. On 11 May 2021, the day-ahead market coupling of Greece and Bulgaria followed, while the coupling of Greece's, Italy's, and Slovenia's Intra-Day Markets were effected in September 2021. In November 2022, Greece entered into Europe’s cross-border intraday continuous market (XBID), through coupling with the Italian and Bulgarian markets.

The Greek State ("State") has submitted a Market Reform Plan to the European Commission ("Commission") Directorate-General for Competition (DG Comp), aiming to optimise the operation of the national wholesale energy markets. Its main component is the establishment of a remuneration scheme for Strategic Reserve power plants, such as the incumbent's (power plant controllers ("PPC's")) lignite power stations, which are no longer profitable.

Natural gas

The commencement of the commercial operation of the Trans Adriatic Pipeline ("TAP") in December 2020 is a significant development in the national natural gas sector. The TAP is connected with the National Natural Gas Transmission System ("NNGTS"), enabling the importation of natural gas from Azerbaijan, as well as the commercial reverse flow of natural gas to Italy. Furthermore, the potential for further advancement in the energy sector is based on the increased activity of NNGTS users at the recently upgraded liquefied natural gas ("LNG") Terminal of Revithoussa. This terminal is also, as of late 2022, providing small-scale LNG services as well as the promotion of four more LNG Terminals in Greece, attributed to the notably low prices of LNG as well as the ever-increasing interest in infrastructure development.

Additionally, the South Kavala Natural Gas Storage project, involving the exploitation of the underwater natural gas field of South Kavala for natural gas storage, is another flagship infrastructure project in the natural gas sector. The relevant public tender is currently in the binding offers phase, following the completion of the pre-qualification process of interested parties meeting the pertinent eligibility criteria.

In January 2022, RAE approved the operation of the Natural Gas Trading Platform (“NGTP”) by HEnEx. The official launch of NGTP's operation in March 2022 signified the creation of a spot market for natural gas in Greece.

RES sector development

The RES sector in Greece is currently experiencing rapid development, as national and international stakeholders have shown great interest in investing in RES projects. This increased interest, along with the simplification and acceleration of the licensing workstreams for the installation and operation of RES power plants by virtue of Law no. 4685/2020 (enacted in May 2020), led to the submission of a record level number of applications to RAE for the issuance of Producers' Certificates in 2020, the total cumulative capacity of which reached 45.5GW. This is a trend which continued in 2022 despite the congestion issues of the transmission system, of which the state is attempting to resolve through legislative measures.

On July 2022, Law no. 4951/2022 entered into force with the objective to further simplify and modernise the licensing framework of RES projects. Furthermore, in August 2022 the Ministry of Environment and Energy ("MEE") issued the grid connection priority framework for RES projects, classifying RES projects into seven priority groups for securing access to the Grid.

By mid-2022, Law 4964/2022 introduced a special framework for the development of offshore wind parks in the Greek territory, while legislative initiatives introduced the framework for the development of storage solutions, both stand-alone as well as combined with RES.

On 1 January 2017, the State adopted a sliding Feed-in Premium ("FiP") operational aid scheme, under which RES producers must actively participate in the wholesale electricity markets while receiving operational aid in the form of a sliding premium to the wholesale price of the energy produced. Through this approach, the State aimed to gradually bring RES projects as close as possible to real market conditions and balancing requirements.

Under the FiP scheme, eligible RES producers must participate in competitive tenders to secure a reference tariff for the compensation of the produced electricity ("RES Tenders"). The Greek RES Tender scheme was approved by the Commission on 4 January 2018 and has so far led to the performance of five technology-specific RES Tenders along with three joint technology RES Tenders during the 2018-2020 tender cycle, as well as one joint technology RES Tender during the 2021 – 2025 tender cycle. The approach taken to date by the State could be characterised as successful, with about 3.5GW of capacity tendered for this period, resulting in the overall lowering of reference tariffs. The Commission recently approved the scheme for the continuation of the RES Tenders for the period up to 2024 for a total capacity of 4.2GW, while the Greek RES market is also becoming interested in the adoption of bilateral Green PPAs.

Guarantees of origin

By virtue of Law no. 4951/2022 2022, the updated regulatory framework for the issuance, supervision, minimum content, revocation, and trading of GOs entered into force. Under the relevant provision of Law no.4951/2022, RAE issued the Regulation for GO Auctions specifying the particulars for the GO system implementation. Via the GO auction process, additional cash flows will be produced in favour of the RES Special Account, which is the funding source for RES producers that receive operational aid. The rationale of the provision is to ensure that the market value of the GOs of RES producers that receive operational aid are appropriately taken into account in the relevant support scheme, in accordance with the provisions of Directive (EU) 2018/2001.

Lignite phase-out

Recent legal initiatives provide for the creation of three Lignite Phase-Out Zones, two in the region of Western Macedonia (regional units of Kozani and Florina respectively) and one in the region of Peloponnese (regional unit of Megalopolis), as part of the country's efforts to promote the gradual transition of lignite areas in Greece. The roadmap for the implementation of Special Zoning Frameworks within the Lignite Phase-Out Zones under the supervision of PPC introduces a favourable licensing framework for RES development within these zones.

Promoting innovative technologies

The special regulatory framework for the development of energy storage applications and their participation in energy markets, as well as the special permitting framework for offshore wind and photovoltaic (PV) parks was approved by the Greek Parliament and published in July 2022. The MEE has long expressed its intention to introduce a special framework for the promotion of hydrogen projects, nevertheless same is currently pending.

In late 2020, a task force was established to compile a special legal framework for energy storage applications, governing, among other topics, the applicable licensing process, the rules for market participation, and the appropriate contractual arrangements of energy storage units with the competent market operators. In the meantime, RAE has already issued the first production licences for energy storage units based on the already existing licensing regime for energy production and supply.

The creation of a similar task force was announced by the MEE, of which mandated to produce a proposal for an appropriate licensing and regulatory framework for hydrogen-based applications in various energy sectors (electricity production, natural gas, transportation). Additionally, the MEE identified the basic issues to be addressed for the forthcoming regulatory framework for offshore wind-parks; these are the licensing and zoning framework, the interconnection of offshore wind-parks with the mainland, and the applicable state-aid regime.

Privatisation of state-controlled energy companies

The Government advanced its privatisation synergies efforts for a number of state-controlled energy companies, through the assignment of its interest to the Hellenic Republic Asset Development Fund (HRADF). The privatisation of the commercial and infrastructure divisions of the Public Gas Company ("DEPA Commercial" and "DEPA Infrastructure" respectively) was initiated in 2021. The process for the privatisation of DEPA Infrastructure, which owns the three major natural gas networks in Greece, was concluded in early September 2021. On the same front, an agreement for the partial privatisation of the state-controlled Hellenic Electricity Distribution Network Operator (HEDNO) through the sale of a 49% stake by the Public Power Corporation S.A. was reached in the autumn of 2021.

Hydrocarbons' research

In October 2019, the Government ratified four concession agreements for the exploration and exploitation of hydrocarbons in four maritime areas located in the Ionian Sea and Crete. These concession agreements concern the maritime area Ionio, which was awarded to the Repsol Exploracion – HELPE consortium, Block 10 (Kyparissia Gulf), which was awarded to HELPE, as well as two maritime areas to the west and southwest of Crete respectively, ie Southwest of Crete and West of Crete, both awarded to the Total – ExxonMobil – HELPE consortium. The ratification of these concession agreements follows the conclusion of similar agreements for the areas of Katakolo, Ioannina, and the Gulf of Patras in 2014, and Aitoloakarnania, Northwest of Peloponnese, Arta – Preveza and Block 2 in 2018, and should interpreted within the context of Greece's efforts to establish itself as an energy hub in Southeast Europe.

Additionally, in June 2021, Block 2 in the Ionian Sea was leased to Total (50%), Edison and HELPE (25% each), the Environmental Action Plans of which were approved by the environmental licensing authority of the MEE.

Conclusion

Despite the recent financial crisis and the COVID-19 pandemic, followed by the energy crisis heightened by the invasion in Ukraine, the Greek energy sector continues to experience increasing growth. The Government's efforts to ease the regulatory framework and comply with European directives on energy market liberalisation, along with increased foreign investor participation in large-scale energy projects and the current dynamic of the emerging RES sector are the current trends in the Greek energy market, while expansions of electricity and natural gas interconnections are promoted.

These developments are the focal point of a comprehensive energy policy seeking to increase competition, advance clean energy projects, promote a commercial mindset in the RES sector, and diversify sources of energy via technological innovations as well as by furthering research into hydrocarbons.

Overview of the legal and regulatory framework in Greece

A. Electricity

A.1 Industry structure

Nature of the market

Greece embarked on the liberalisation of its electricity market in 1999 and subsequently revised the legal framework in order to comply with European Union ("EU") legislation and to incentivise private investment and competition. Greece's strategic location between energy producers in the Middle East, North Africa, and the Caspian Sea, as well as on the vital transport routes of the Aegean Sea and the Eastern Mediterranean, characterises it as a significant energy hub, connecting the East with the West. Greece's prospects are becoming more evident recently in the context of the ongoing crisis following the invasion in Ukraine. Recent electricity market developments and new interconnections with neighbouring countries have led to the market coupling of Greece with Italy and Bulgaria. Such coupling has the aim of increasing energy security and supporting both further renewable energy sources ("RES") integration and wholesale price competition.

The Greek electricity market has been shaped by a series of key legislative acts over the past two decades. This legal framework,[1] along with the Grid Codes and a series of secondary legislation in the form of Regulations, Ministerial Decisions, and other Administrative Acts, establish the organisational and operational rules for the electricity market, as well as the fundamentals and the restrictions that characterise its structure. The country is continuously following the necessary steps for the modernization of its electricity market and has recently adopted measures for the full transposition of Directive (EU) 2019/944 on common rules for the internal market for electricity through Law 4986/2022. This aims inter alia to promote the transition to lower emission technologies, transparent market pricing, and safeguarding national security of supply.

Key market players

The Public Power Corporation ("PPC") is the dominant electricity producer and supplier in Greece. Following the conclusion of a share capital increase in late 2021, PPC's two largest shareholders are the Greek State (the "State") (34.12%) and Selath Holdings Sàrl (CVC Capital Partners – 10%). The remaining shareholding (55.88%) is held by institutional and private investors, including Helikon Investments Limited.

The Hellenic Distribution Network Operator ("DSO") (ie DEDDIE) is a subsidiary of the PPC resulting from the separation of its distribution segment under the Energy Law. The DSO is independent in its operation and management, retaining all the operational independence requirements that are provided for in the Energy Law. The DSO is responsible for all activities relating to the maintenance and development of the electricity distribution network, as well as for ensuring transparent and impartial network access to consumers and all users in general. The partial privatisation process of the DSO was concluded in the fall of 2021 through the sale of a 49% stake to the Macquarie Infrastructure and Real Assets Group. The completion of the transaction, involving the transfer of ownership of the distribution network assets from PPC to the DSO, was completed in February 2022.

The Independent Transmission Operator ("ITO") (ie ADMIE), and Transmission System Operator ("TSO"), which until July 2017 was a subsidiary of PPC,[2] is the owner and operator of the High-Voltage Transmission System ("System") and accordingly is responsible for its operation, exploitation, development, and maintenance, as well as for the operation of the balancing market. Following full ownership unbundling ("FOU"), PPC has fully divested its interest in the TSO. The present shareholders are State Grid Europe Limited (a 100% subsidiary of State Grid International Development Ltd), controlling 24% of the TSO, the Public Holding Company ADMIE SA (owned 100% by the State), controlling 25% of the TSO, and ADMIE HOLDING SA, listed on the ATHEX (51.1% owned by the Public Holding Company ADMIE SA), controlling 51% of the TSO.

The Operator of Renewable Energy Sources and Guarantees of Origin SA[3] ("Operator of RES") (previously the Electricity Market Operator ("LAGIE")), is the RES operator, which is exclusively controlled by the State. The RES operator is responsible for the operation of RES and Guarantees of Origin ("GOs"). Its activities are carried out in accordance with the Code of the RES Operator and GOs.

The Hellenic Energy Exchange SA ("HEnEx") was established in the context of the reform of the Greek energy market, ie towards its harmonisation with the requirements of the general framework of the new operating model of the wholesale electricity market ("Target Model").[4] The registered shareholders of HEnEx are: Operator of RES (22%), Athens Exchange Group (21%), ADMIE (20%), EBRD (20%), Hellenic Gas TSO SA ("DESFA") (7%), and Cyprus Stock Exchange (10%). Under the new framework, LAGIE assigned or contributed all of the activities that were relevant to the operation and the management of Day-ahead Scheduling ("DAS"), including the organisation and implementation of auctions for the sale of electricity forward contracts ("NOME" auctions),[5] for the purposes of establishing the HEnEx (by way of spin-off). HEnEx is responsible for the administration and the operation of the day-ahead market, the intraday market,[6] and the energy financial instruments or products market.[7] HEnEx holds a licence from the Regulatory Authority for Energy ("RAE") to perform the above activities, and a licence from the

Hellenic Capital Market Commission for the energy financial instruments or products market.

Regulatory authorities

The government bodies and institutions that oversee and regulate the electricity market are:

- RAE, an independent authority that supervises and monitors the operation of all sectors of the energy market, and that advises the competent authorities on compliance with competition rules and consumer protection.
- The Ministry of Environment and Energy ("MEE"), which is principally responsible for the formulation and implementation of Greece's energy policy in relation to its international and EU Community ("Community") obligations (ie the transposition of relevant EU Directives and the alignment of national policies with EU Regulations and strategies).
- The Ministry of Economy and Development, which can indirectly affect energy matters through its monitoring of petroleum product prices and, more significantly, through its responsibility for administering EU Cohesion Funds.

Legal framework

The fundamental legal instrument regulating the structure and operation of the electricity market in Greece is the Energy Law, governing, among other things, the activities of electricity generation, storage, aggregation, supply, and trading. The Energy Law furthermore establishes the pertinent electricity transmission and distribution framework along with the applicable unbundling regimes.

The Greek wholesale electricity market underwent a complete overhaul through the implementation of the Target Model, ensuring conformity with the requirements of the EU Target Model and enabling its gradual connection with the European markets. Auctions in accordance with the NOME model commenced in October 2016. The auctions enhanced competition between power suppliers by providing all power suppliers access to the less expensive lignite electricity production of the dominant power producer (ie, PPC). The auctions ceased in early 2021 in the context of the operation of the Target Model markets and the acceleration of the lignite-phase out. Due to recent developments,[8] PPC must sell quarterly forward electricity products on the organised exchanges of the European Energy Exchange AG ("EEX") and/or the HEnEx.

Even though the State enacted Law no. 4425 in 2016 to reorganise the electricity market in accordance with EU rules[9] for the completion of the single European Market, the initial version of the law proved to be inadequate. It adopted a very conservative approach in introducing the principles of the Target Model. Law no. 4425/2016, was criticised for not achieving the introduction of the required regulations. It was more a law primarily acknowledging the Target Model instead of introducing a completely open environment for its implementation.

The enactment of Law no. 4512/2018 introduced an evolution in the energy legislative sector. Law no. 4512/2018 adopted decisive steps among which was the establishment of HEnEx, followed by the structural reformulation of the particular and individual sectors of the energy market. The electricity transactions are currently designed to be carried out in four different markets (see section A.3).

HEnEx provides access to new liquid energy markets and products that will, among other things, support greater domestic competition, reduce barriers to entry for new energy market participants, and allow the effective participation of renewable energy producers in the electricity markets. HEnEx also supports regional integration by facilitating market coupling with Greece's neighbours (ie Italy and Bulgaria).

Furthermore, HEnEx offers a comprehensive set of new energy trading products well above the minimum requirements for compliance with the EU Target Model, including a new spot (in the context Day-Ahead and the Intraday Market) plus new physical and cash settled energy derivative products (see section A.3). Through the introduction of physical and cash settled energy derivative products, HEnEx is a platform that accommodates domestic and regional market participants, providing them the opportunity to hedge their electricity market risk in different time frames, as well as to improve price discovery across the curve.

Implementation of EU electricity directives

EU directives are transposed into the national legal system by the Ministry with the relevant competencies. Electricity directives are therefore implemented by virtue of legal acts by the MEE. Greece has implemented the EU electricity directives by means of various legislative acts, including the Energy Law (which transposed the Third Energy Package) as lately amended by Law 4986/2022 (transposing directive 2019/944), Law no. 3468/2006 (which transposed the Promotion of RES Directive), and Law no. 3851/2010 (implementing the RES targets of the Renewable Energy Directive).

A.2 Third party access regime

ADMIE adopts all necessary measures to ensure immediate and uninterrupted connection to, and use of the transmission system by users. To this end, ADMIE must make a connection offer to users, with the aim of concluding a connection agreement under which the parties commit to perform the agreed system development works.

The cost of implementation and commissioning of the connection expansion works are exclusively borne by the applicant. However, the ownership of the conducted works may either remain with the producer or be passed to ADMIE depending on the type of works. RAE may decide that new direct interconnectors are exempted from third party access for a limited period of time.

A.3 Market design

Before the target model

Law no. 4001/2011 introduced the mandatory pool model for the organisation of the wholesale electricity power market. Until the implementation of the Target Model, the Greek wholesale market was operated based on a mandatory mechanism of the day-ahead wholesale under DAS. This mechanism is, in essence, an auction that is subject to certain rules of operation and price formation.

The accounting or settlement price of DAS was defined as the System Marginal Price ("SMP"). The SMP was configured through the operation of the wholesale market based on the submitted offers and primarily according to the rules of a free market, ie based on demand and supply. Any transactions for the entire capacity of electricity and of supplementary goods was obligatorily performed in the context of this mandatory wholesale market, and no bilateral transactions were permitted ie between the participants of the wholesale electricity market.

Energy market after the enactment of the Target Model Law

Law no. 4425/2016, the Target Model Law, introduced the general framework of the new operating model of the wholesale electricity market, ie the Target Model which was implemented as of 1 November 2020 following several years of EU legislative regime harmonisation efforts.[10]

The Target Model Law introduces the following wholesale markets:

- day-ahead market (operated by HEnEx);
- intraday market (operated by HEnEx);
- imbalances market (operated by ADMIE); and
- financial energy (derivatives) market (operated by HEnEx).

The operation of the Day-Ahead and the Intraday Market is administered by HEnEx, under the provisions of the HEnEx Spot Trading Rulebook,[11] while the clearing and cash settlement of the positions that arise in this market are monitored by EnExClear in accordance with the Clearing Rulebook for Transactions on the Day-Ahead and Intraday Market.[12] In addition, the operation of the Balancing Market is monitored in accordance with the Balancing Market Rulebook,[13] while the clearing and settlement of the positions that arise in this market are regulated by the Clearing Rulebook for Positions on Balancing Market.[14] Lastly, the operation of the Financial Energy Market, where energy financial instruments are traded, is administered by the HEnEX, in accordance with the Derivatives Trading Rulebook. The newly created market structure is primarily based on the day-ahead market.[15] In this market, the electricity transactions are carried out on a 'physical delivery' mode. Therefore, the market involves cash settled transactions of immediate delivery and does not involve transactions of forward energy products. The day-ahead market is coupled with an intraday market and a balancing market. In the intraday market, physical delivery transactions are carried out according to orders submitted after the end of the submission period in the context of the day-ahead market. The day-ahead market and the intraday market contribute in advance, to the balancing between offer and demand as such a function relies on the estimation of the day-ahead demands. The balancing market is the mechanism for resolving imbalances between offers and demand of electricity, given that if there is an imbalance in the performance of the contracts for the delivery of electricity products on an hourly basis, such imbalances are settled by this market.

The Target Model Law[16] provides for alternative options with respect to the clearing and settlement of the transactions of the day-ahead market and of the intraday market which may be carried out by HEnEx, a clearing house or a central counterparty ("CCP") of the European Market Infrastructure Regulation ("EMIR"). The second option is currently adopted,[17] according to which the clearing and settlement of the transactions of the day-ahead and the intraday market will be carried out by a clearing house established by HEnEx. The clearing house was created in November 2018 under the distinctive title 'EnExClear SA' and operates under the respective operation licence and the approval of its regulation by RAE,[18] as of the commencement of operation of the day-ahead market and of the intraday market (1 November 2020).

The Target Model Law provides that the clearing of the balancing market transactions will be carried out by ADMIE, which is entitled to assign certain clearing functions to a clearing house or a CCP on RAE's approval.[19] Clearing of the balancing market is currently performed by the EnEx Clearing House SA.

The operation of the financial energy market, where energy financial instruments are traded, is administered by the HEnEX.

HEnEx market and the introduction of the financial instruments or products

The Target Model Law establishes a significant expansion of the available electricity trading mechanisms by introducing the energy financial instruments or products.[20] In such a market, these financial instruments or products are negotiable instruments and are, provided they are related to energy goods, meant to be defined as financial instruments and provided for in MiFID II (cases 5-11 of Annex 1).[21]

The possibility for conclusion of such contracts was introduced in the Greek energy market by the above amendments. The relevant market, being a new reality for Greece, is not fluid yet. It remains to be seen in the future whether physically settled agreements will prevail over cash (economic) settlements. In particular, transactions that involve energy financial products can be concluded outside the HEnEx market through bilateral contracts directly between the contractual parties.[22]

According to the Target Model Law, HEnEx received a licence[23] from the Hellenic Capital Market Commission for the operation of the financial energy market. Additionally, HEnEx entered into the necessary agreements with the Athens Stock Exchange SA ("ATHEX SA") and its subsidiary (ie the Clearing House of the Athens Stock Exchange Company SA ("ATHEXClear SA"), in order for the latter to undertake the clearing of the transactions.

Transformation of the regulatory landscape: from codes to rulebooks

The Target Model introduces, from a systemic perspective, the requirement to issue specific rulebooks for each market section, as the markets are now regulated. Before the introduction of the Target Model Law, the regulatory framework was organised, technically, with the adoption of codes, whereas under the Target Model, the form of rulebooks has been introduced as the instrument to regulate the related market specifics.

Given this approach, the adoption of the HEnEx Spot Trading Rulebook[24] was effected at the end of 2018 on the recommendation of the Board of Directors of HEnEx following the approval by RAE.[25] The above rulebook sets out the terms and conditions for the operation of the day-ahead market, as well as the intraday market on the basis of objective and transparent rules in the absence of any discrimination with regard to the access of the participants in those specific markets. The commencement of the operation of the day-ahead market and the intraday market initially provisioned for 6 June 2019 took place on 1 December 2020, following multiple delays and fine tunings of the applicable framework.

As also required by the Target Model Law, in the end of 2018 the Balancing Market Rulebook ("BM Rulebook")[26] was effected following RAE's approval of ADMIE's recommendation. The BM Rulebook establishes the terms and conditions for the operation of the balancing market based on objective and transparent rules in the absence of any discrimination relating to the access of the participants in the markets in question. Furthermore, the rules and procedures for carrying out the transactions in those markets, as well as the connection with the settlement mechanism and the consequences of a breach of its rules are addressed in BM Rulebook.

The introduction of the Clearing Rulebook for Transactions on day-ahead market and intraday market ("Clearing Rulebook") constitutes an innovation of the Target Model Law.[27] The Clearing Rulebook seeks to establish under new grounds the concept of clearing and settlement according to the type of transactions settled, and the intermediary who will undertake the relevant role that is crucial for the operation of the market. Article 18.3 of Law no. 4425/2016 outlines the material contents of the Clearing Rulebook, which include the rules for access to the clearing functions, the obligations of the clearing members, the rules governing risk management, along with the provisions relating to the securities for safeguarding the claims incurred from the transactions settled.

If a CCP of EMIR,[28] which has been licensed in Greece under Article 100 of Law no. 4209/2013, undertakes the clearing of transactions of the day-ahead and the intraday markets, the clearing process is conducted according to the CCP's Regulation. This is drawn up in accordance with EMIR and the CCP Technical Standards Regulation.[29] Within the above rules and their scope, the potential clearing of the balancing market by such CCP is also explicitly applicable.

The structural amendments effected by the Target Model Law[30] also resulted in the adoption of the Code of Operator of RES.[31]

Measures in view of the ongoing energy crisis

The effects of the ongoing energy crisis, heightened by the circumstances brought on by the invasion in Ukraine which culminated to a surge in both the wholesale and retail electricity prices reaching an all-time high during the end of the past year, led the Greek government to introduce a number of measures in 2022, including setting price caps in the wholesale income of electricity producers, the subsidization of retail consumers' electricity bills, as well as the imposition of additional taxes on producers' windfall profits. The above challenges resulted also to the increase in national lignite production and the gradual rise in the participation of lignite-fired power plants in the country's energy mixture.

A.4 Tariff regulation

TSO costs and expenses deriving from the development and the maintenance of the system are recovered by system users through the system tariffs in accordance with the relevant Regulatory Remuneration Methodology.[32] The Regulatory Remuneration Methodology is a revenue cap incentive regulation, with Allowed Revenue ("AR") set for the duration of the regulatory period on an ex-ante basis. Its main objective is to enable the TSO to recover the reasonable and efficient costs of providing Use of System services in a reliable, safe, and secure manner. The term of the first regulatory period was set for three years, ie from 2015 to 2017, and four years thereafter, while the second regulatory period commenced on 2022 and shall end on 2025.[33]

Ad-hoc reviews are provided in certain cases including:

- Extraordinary and unforeseen events; and
- Significant changes to economic, legal, and other conditions on which the AR was calculated, such as cost of debt, tax rate, consumer price index inflation, and change in other weighted average cost of capital parameters.

System tariffs are calculated on the basis of the following process:

- RAE decides on the TSO's AR for each year of the regulatory period taking into consideration the following parameters comprising the AR:
  - the budgeted annual operational expenses of the transmission system; and
  - the annual depreciation and return on the regulatory asset value, excluding interest and tax.
- If necessary, RAE smoothens the fluctuations of the AR between the years of the Regulatory Period and calculates the TSO's Required Revenue ("RR") for the next year, which comprises of the AR and other parameters such as:
  - over and under-recovery of revenues through the application of the system tariffs of previous years;
  - liquidation due to under- or over- investment in previous years;
  - revenues from the tendering of interconnection rights; and
  - other revenues deriving from regulated or non-regulated activities of the TSO.
- RAE calculates and approves on the basis of the RR of the following year the unitary system tariffs for all system users until 30 November of each year.

Similar provisions also apply for the determination of tariffs for the use of the distribution network. The new Electricity Distribution Network Code[34] establishes the general outline of the Methodology for the Calculation of the RR, which is similar to the methodology applied for the TSO's RR and sets the methodology for the calculation of use tariffs for the distribution network for each category of electricity consumers.

A.5 Market entry

Subject to licensing restrictions, liberalisation has lifted the barriers to entry into the electricity market.

Generation

Under the Energy Law, the development, construction, commissioning, and operation of power generation facilities is extensively regulated by a number of legislative acts, which provide for three basic licences:[35]

- the Electricity Generation Licence, which can only be granted to legal entities based within the EU and/or EU citizens;
- the Installation Licence, in conjunction with the environmental licensing of the respective facilities, which is a prerequisite for the performance of construction works, the power plant's connection with the grid and the sale of the produced electricity; and
- the Operation Licence, which is issued following connection of the power plant with the grid, completion of the

interconnection works and successful trial operation.

Transmission and distribution

The ownership, and the transmission and distribution activities of the electricity sector, can only be performed with the granting of a relevant licence and certification process, as per the Energy Law.

Electricity trading and/or supply licence

The issuance of an Electricity Trading and/or Supply Licence is regulated by the Energy Law and the provisions of the Electricity Licensing Regulation.[36] Both the Energy Law and the Electricity Licensing Regulation differentiate the criteria for the issuance of these licences on the basis of the type of the licence requested, and the legal form of the applicant entity, among other things, while concurrently setting additional related requirements.

Legal entities based within the EU, Member States of the European Economic Area ("EEA"), members of the Energy Community, and/or states that have executed bilateral treaties either with the EU or with Greece are eligible to obtain an Electricity Trading and/or Supply Licence. Alternatively, an interested entity can establish a branch in Greece. An entity's engagement in the activities of electricity supply or trading in another EU Member State entails the application of more favourable market entry rules.

Storage

In accordance with the recent amendments to the Energy Law, the development, construction, commissioning, and operation of electricity storage facilities, with regards to stations of capacity equal to or greater than 1MW is permitted to persons holding a relevant license issued by RAE in accordance with the criteria introduced by the Energy Law and which shall be further specified by a relevant regulation. The EU Commission approved in September 2022 the Greek aid scheme for the construction and operation of electricity storage facilities of up to 900 MW to be connected to the transmission system by the end of 2025, as the scheme was envisaged in Law 4920/2022.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Companies required to provide public services to their customers (mainly power suppliers) must ensure that electricity is made available to the consumers of the non-interconnected islands and the remote microsystems at the same pricing level as the one applied at the interconnected system, per consumer category. In addition, they must ensure that electricity is provided under a special pricing scheme for large-family consumers and 'financially weak groups', as per the relevant legislation.

Smart metering

Ministerial Decision Δ5/ΗΛ/Α/Φ33/2067 titled "*Replacement of metering systems for the final consumption of electricity*" (*Αντικατάσταση συστημάτων μέτρησης τελικής κατανάλωσης ηλεκτρικής ενέργειας*) established a target of providing no less than 80% of electricity customers with a smart metering system by 2020. Specifications of smart metering systems were aligned with current EU standards through the amendment of the Energy Law by Law 4986/2022. Although the implementation of actions to reach the above target has fallen short, according to its 2021-2025 Network Development Plan, the DSO plans to install 7.5 million 'smart' meters throughout the low-voltage distribution network within a ten-year period. The DSO finally commenced the relevant tender process in 2022 and the binding stage will take place within 2023.

Electric vehicles

Greece has not yet experienced a widespread development of electric mobility, despite significant efforts promoting electric vehicle ("EV") ownership, mostly due to the recent financial crisis and the fact that a robust charging network is still under development.

The Greek National Energy and Climate Plan (NECP) has set a target for EVs to reach a 30% share of the automobile market. The national legal framework is aligned with EU legislation and the Alternative Fuels Directive,[37] while the ad hoc regulatory framework for the installation and operation of an EV charging infrastructure was adopted by virtue of Law no. 4710/2020.

The new law provides a complete regulatory framework for the development of the national EV market. The main focus points include the introduction of tax incentives for business, the definition of the role of the market players, and the development of the necessary charging infrastructure and other benefits or regulatory exceptions, such as free parking and low emission zone passes. Furthermore, the first subsidy scheme available to natural and legal persons offered a bonus for the purchase of any type of EV.

Although the Greek EV market is still in development, an increasing trend is noticeable. The total number of EVs increased from 62 in August 2014, to 2,131 in August 2020. Sales were positively affected through the subsidy scheme and 10% of the December 2020 market share was attributed to EVs. This trend is attributable to relevant measures including purchase incentives or subsidies, tax benefits and exemptions, other benefits (eg free parking), infrastructure promotion measures, and traffic regulations (eg bus lanes and low emission zones).

Law 4936/2022 moreover, introduced ambitious targets for the penetration of zero emission vehicles. This included pursuing the aim of all passenger vehicles being introduced to circulation as of 2030 being solely zero emission vehicles.

A.7 Cross-border interconnectors

The Greek Transmission System is interconnected in the north with Bulgaria, North Macedonia, and Albania; to the west with Italy through an underwater interconnector; and to the east with Turkey. All transmission lines, including interconnectors, are operated by the TSO according to the provisions of the Energy Law. Under recent legislation,[38] the TSO may assign all or part of its responsibilities to new or existing entities, but nevertheless retain overall responsibility for the proper operation of the transmission system.

Oil and gas

B.1 Industry structure

Oil

Nature of the market

Hydrocarbon research, exploration, and exploitation activities are regulated by Law no. 2289/1995 ("Hydrocarbons Law"), as amended and in force. Furthermore, Law no. 3054/2002 regulates oil policy issues in Greece along with the activities of refining, trading, transport, and storage of crude oil and petroleum products. Refiners are permitted to sell petroleum products directly to large final consumers. Oil companies trading in the Greek wholesale segment are legally separated from refining operations and are permitted to import and export petroleum products. In turn, such companies are permitted to sell these products to large final consumers and retailers. Overall, with the exception of substantial exports of refined petroleum products, Greece remains highly dependent on hydrocarbon imports.

Gas

Nature of the market

The Greek high-pressure National Natural Gas System ("NNGS") includes interconnections with Turkey and Bulgaria, the Trans Adriatic Pipeline ("TAP"), and a liquefied natural gas ("LNG") terminal located in Revithousa Island. The country offers a unique advantage for entities involved in natural gas activities due to increasing consumption needs, also accounting for the country's potential as an entry point for south-east and mainland Europe.

Key market players

The key market players in the natural gas market are:

- The DEPA Commercial SA ("DEPA Commercial"), a state-controlled natural gas company vested with the non-exclusive rights to import, export, and trade (supply) natural gas. The former Public Gas Corporation ("DEPA") was renamed to DEPA Commercial, following the demerger of its distribution branch[39] and is the main natural gas and LNG importer in Greece. The Hellenic Republic Asset Development Fund SA ("HRADF") holds 65% of its shares and the remaining 35% are held by Hellenic Petroleum SA ("HELPE"), however the privatisation process has not progressed.
- The DEPA Networks SA ("DEPA Networks"), a formerly state-controlled natural gas undertaking, aiming to develop natural gas networks across Greece through its subsidiaries. DEPA Commercial was established in April 2020 following the partial demerger of DEPA's distribution branch. Initially owned by the HRADF (65%) and by Hellenic Petroleum SA ("HELPE" – 35%) the privatisation process was completed in late 2021 resulting in the conclusion of a share purchase agreement for the transfer of 100% of DEPA Networks shares to Italgas SpA.
- The Natural Gas-Hellenic Energy Company SA (ie the former Natural Gas Supply Company of Attica-EPA Attica) is a natural gas supplier eligible to supply gas throughout Greece and a wholly owned subsidiary of DEPA Commercial, following the acquisition of Shell Gas BV's participation in the company at the end of 2018.
- The Gas Supply Company of Thessaloniki-Thessalia SA (formerly EPA Thessaloniki-Thessalia), with the distinctive title 'Zenith SA'; since July 2018 Zenith's sole shareholder is ENI Gas e Luce, as it acquired the remaining 51% from DEPA.
- The Public Enterprise of Gas Distribution Networks SA ("DEDA") is a wholly owned subsidiary of DEPA Networks, established in early 2017. DEDA is the Operator of the Gas Distribution Networks throughout Greece, except for the regions of Attica, Thessaly, and Thessaloniki.
- The Gas Distribution Company of Attica SA (EDA Attica), is the Operator of the Gas Distribution Network of Attica since January 2017. It is wholly owned by DEPA Networks following the acquisition of Shell Gas BV's participation at the end of 2018.
- The Gas Distribution Company of Thessaloniki-Thessalia SA (EDA Thessaloniki-Thessalia) was established in 2017 and is the Gas Distribution Network Operator within the geographical areas of the prefecture of Thessaloniki and the region of Thessaly. It is owned by DEPA Networks (51%) and by ENI Gas e Luce SPA (49%) with management rights.

The DESFA, operator of the NNGS, the privatisation of which was concluded on December 2018,[40] is a certified EU TSO under the FOU model and a LNG system operator, the activities of which are established as per the Third Gas Directive[41] and includes the operation, maintenance, and development of secure, reliable, and efficient transmission and LNG facilities. DESFA develops the NNGS in accordance with the Ten Year Development Plan ("TYD Plan") that is presented for public consultation and is annually approved by RAE. The TYD Plan outlines the development of NNGS infrastructure including major capacity expansion works and Interconnector Projects (eg in LNG regasification facilities). Adherence to the TYD Plan is subject to regulatory scrutiny.

Regulatory authorities

The governmental bodies and institutions that oversee and regulate the natural gas market are:

- RAE; and
- the MEE.

For more on RAE and the MEE, see section A.1.

Legal framework

The primary legislation is the Energy Law, under which gas supply companies no longer enjoy exclusivity in supplying gas to low and medium pressure customers within their original licensed (regional) jurisdictions, as all customers have become eligible as of January 2018. Such activities are now open to any interested party and as a result the market has been opened up to new participants and gas suppliers are not limited within a specific geographical area.

The exercise of other natural gas activities within the territory of the State, however, under the Energy Law, constitutes a public service and is performed under the supervision and regulation of the MEE. The supply and distribution of natural gas to eligible customers, as well as the construction and operation of Independent Natural Gas Transmission Systems ("INGS"), are permitted only to holders of the respective licences, issued by RAE.

Implementation of EU gas directives

The natural gas market liberalisation initially came with the enactment of Law no. 3428/2005, which transposed the Second Gas Directive, and which was subsequently replaced by the Energy Law. This transposed the Third Energy Package into national legislation.

B.2 Third party access regime to gas transportation networks

DESFA must provide system users with access to the NNGS in the most economic, transparent, and direct way for as long as the users wish. Access to the system may be refused for certain reasons, in which case DESFA must specifically substantiate its reasoning. In a similar vein, operators of INGSs are subject to third party access obligations, subject to exemptions that may be provided by RAE in consultation with the EU Commission ("Commission"), in accordance with the provisions of the Energy Law.

The relevant transportation tariffs, under the NNGS Operation Code, set out that the shipper must pay a fee to DESFA on a monthly basis for the use of the system in accordance with the published NNGS tariff regulations for gas transportation. The general principle behind the consideration is based on the charge for the capacity transportation reserved by the shipper each year and the charge for the gas quantity transported each year on the shipper's behalf.

B.3 LNG terminals and gas storage facilities

Greece has one LNG import terminal, located west of Athens on the island of Revithousa, with a regasification capacity of 1.250m³/h, and a storage capacity of 225,000m³, which is part of the NNGS and is operated by DESFA. Recent developments led to the establishment of additional storage to the terminal through enhancement of the facilities by means of a floating storage regasification unit. The TSO, as of late 2022, also provides small scale LNG services through Revithousa . An LNG Terminal in the area Alexandroupolis, Northern Greece, with a regasification capacity of up to 400m³/h, is being developed by Gastrade S.A.. The LNG Terminal is scheduled to become operational by 2023, while an LNG Terminal in Korinthos is being promoted by Dioryga Gas S.A. with a licensed regasification capacity of 300-500m³/h. The increase in the regional gas demand further led to the promotion of similar investments in the areas of Volos (issued with a license within 2022) and Thessaloniki.

Furthermore, the public tender for the conversion of the depleted South Kavala Gas Field into an underground gas storage facility, an infrastructure project with a storage capacity sufficient to supply Greece with natural gas for an uninterrupted period of 90 days, is still ongoing.

These projects aim to ensure that sufficient natural gas quantities reach the Greek and regional markets, while also contributing to the enhancement of the NNGS.

B.4 Tariff regulation

In accordance with the current Tariff Regulation,[42] the tariffs relating to Basic Natural Gas Activities are determined on the basis of the principle for recovery of the RR in relation to each basic activity of DESFA and in particular based on the forecast for the evolution of the RR and natural gas demand, for every year of a time period of four consecutive years ("Tariff Calculation Period"). Ex-post data referring to the actual RR and the actual revenues for every year of a certain period prior to the Tariff Calculation Period ("Revision Period") are also taken into account in order to ensure that no under or over-recovery of RR has occurred.

Regular tariff revision is conducted within the fourth year of each Tariff Calculation Period.

The main objectives that are considered for the determination of natural gas tariffs include:

- stability of the tariffs to the benefit of users;
- reasonable return on the capital invested by DESFA;
- provision of services in the most reliable and economically viable way; and
- recovery of the expenditure made by DESFA for the fulfilment of public service obligations ("PSOs").

Similar provisions also apply for the determination of the tariffs for access to the distribution networks. Tariffs for the basic activity of distribution are determined by the relevant local gas distribution companies following approval by RAE in accordance with the relevant provisions of the tariff regulation.[43]

B.5 Market entry

The Natural Gas Licences Regulation[44] requires the issuance of the following licences in order for an entity to engage in the respective activity:

- Independent Natural Gas Transmission System licence;
- Independent Natural Gas Transmission System Operation licence;
- Natural Gas Distribution licence;
- Natural Gas Distribution Network Operation licence; and
- Natural Gas Supply licence.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Article 55 of the Energy Law sets the general framework for the PSOs of undertakings in the energy sector, however no specific obligations have been introduced for natural gas companies.

Smart metering

Despite the general framework, as set by Article 59 of the Energy Law, there is currently no secondary legislation in place specifying smart metering measures for natural gas.

B.7 Cross-border interconnectors

Greece is seeking to diversify its natural gas imports by sourcing natural gas from countries such as Iran and Azerbaijan and is cooperating with several nations that are constructing pipelines. Azeri gas is transported via Turkey through the TAP, which is connected to the main line of the NNGS and further interconnects Greece to Italy through Albania, following the commencement of its operation in early 2021.

The IGB pipeline, which has been classified as a Project of Common Interest to the EU, was inaugurated in July 2022 and is set to become operational in October 2022. The IGB pipeline, with a transmission capacity of three billion cubic meters ("bcm") of gas per year, can potentially be used as a starting pipeline for exporting LNG to the Balkans and Central Europe. The implementation of the East-Med pipeline (estimated at ten bcm), for which Greece, Israel, and Cyprus signed the final agreement January 2020, is also progressing, especially in the context of the EU's efforts to eliminate its dependence on Russian gas.

C. Energy trading

C.1 Electricity trading

Electricity trading transactions are performed in the day-ahead Market, the intraday market, the balancing market, and the Financial Energy Market, in accordance with the pertinent market Rulebooks (see section A.3).

Greece took the first step towards EU Market Coupling on 15 December 2020, with the Day-Ahead Market coupling of Greece and Italy. On 11 May 2021, the Day-Ahead Market coupling of Greece and Bulgaria followed, while the coupling of Greece's, Italy's, and Slovenia's Intraday Markets was completed in September 2021. In November 2022, Greece entered into Europe's cross-border intraday continuous market (XBID), through coupling with the Italian and Bulgarian markets.

C.2 Gas trading

As of the beginning of 2018, Greece's natural gas market is fully liberalised, with all customers being free to purchase gas from the supplier of their choice. Upon their registration with the NNGS, natural gas supply companies have the right to supply other suppliers or customers (including end-customers) with natural gas throughout the country under the terms and conditions of their respective supply licences and the Gas Supply Code. Trading of natural gas takes place through bilateral contracts.

As per the NNGS Operation Code, DESFA must provide natural gas transmission and LNG services on the basis of framework agreements executed with NNGS users. Capacity booking in entry points by NNGS users takes place via auction procedures or via an agreement under the 'first come first served' rule only for unallocated capacity of the Revithoussa LNG Terminal. The organised wholesale gas market within the HEnEx officially started its operations in March 2022. The trading platform will initially allow spot transactions and at a later stage trading of futures products, boosting the potential of the creation of a regional energy hub.

D. Nuclear energy

There are no nuclear energy activities in Greece.

E. Upstream

Further to the Hydrocarbons Law and Law no. 2321/1995 that ratified the United Nations Convention on the Law of the Sea (UNCLOS), the right to research, explore, and produce hydrocarbons existing in onshore areas, sub lakes, and submarine areas, where the State has either sovereignty or sovereign rights, is exclusively granted to the State.

Following the enactment of the Energy Law and by virtue of Presidential Decree 14/2012, the state company Hellenic Hydrocarbons Resource Management ("HHRM" or "EDEY", as per its Greek acronym) was established to undertake the responsibility of particular matters relating to the management of the process of research, exploration, and production of hydrocarbons. HHRM is the competent body to grant research licences to third parties following an open tender procedure and with the MEE's approval for a period of up to 18 months. The area to be researched cannot exceed 4,000km^2 with respect to onshore areas and 20,000km^2 with respect to offshore areas. The granting of research licences to several applicants for the same area is permitted. The granting of such a licence is only for the purposes granted and does not confer any other right to the licensee as to its activities.

The holder of a research licence must, immediately after its granting, submit to HHRM a comprehensive research programme divided into phases and, following completion of each phase, must submit copies of all technical and scientific data and conclusions that resulted from the research carried out in that phase. Within three months of the expiration of the licence, the licensee must submit to HHRM a detailed report, accompanied by official information and data, analysing the results of the research programme. Breach of the foregoing obligations by the licensee, as well as any breach of the terms of the invitation or the licence, may result in the revocation of the licence and in forfeiture of the guarantee in favour of the State.

The State's rights of exploration and production of hydrocarbons may be granted to third parties via either the conclusion of a lease agreement or the conclusion of a production sharing agreement. Each agreement will concern one or more adjacent onshore or seabed areas which will comprise the initial exploration area for the discovery of hydrocarbon deposits ("Contract Area"). The Contract Area will eventually be restricted to the area where commercially exploitable hydrocarbon deposits have been discovered ("Production Area"). Under both agreements the contractor assumes the obligation and exclusive right to plan and perform the exploration and production of hydrocarbons. The contractor provides, at its own expense, the necessary technical equipment, materials, personnel, and funds required for the performance of the activities, bearing the entire relevant financial risk, particularly if no commercially exploitable deposit is discovered or if the profit yield from a deposit is insufficient. The contractor manages the project, which will be carried out in accordance with the international models for the exploration and production of hydrocarbons and under the work programme and budget approved by the employer or the lessor, as the case may be.

Under the production sharing agreement, in the event of a discovery and production of hydrocarbons, the contractor will retain part of each calendar year's total production of hydrocarbons and by-products of each Production Area in order to cover the relevant expenses specified in the Hydrocarbons Law. The remainder of the production from the Production Area is shared between the employer and the contractor on the basis of an agreed upon fixed percentage.

Under the lease agreement, in the event of the discovery of a commercially exploitable deposit, the contractor, by notification to the lessor, becomes lessee of the right of production from the deposit. As a result, they must produce hydrocarbons and their by-products and to market the same for their own benefit, either in their crude state or following processing, excluding refining, by paying to the lessor the rent and relevant tax. The rent is due to the lessor in all circumstances, irrespective of whether the contractor makes a profit or not, and is agreed to be paid in kind as a percentage of the quantities produced or in cash, as a percentage of their value.

Presidential decrees, which are issued following a proposal of the MEE, specify in detail the terms and conditions of the agreements such as the contents and the timetable for the submission for approval of the exploration and production programmes and the expenditure budgets.

HHRM will grant, on behalf of the State, the right to explore and produce hydrocarbons in accordance with the procedures specifically stipulated by the Hydrocarbons Law and more particularly either:

- on an invitation to tender;
- on an application by the interested party for an area not included in the invitation to tender; or
- with an open-door invitation for the expression of interest.

Under the agreements concluded, contractors may be natural persons and/or legal entities, acting individually or in a joint venture, provided they have the nationality of, in the case of a natural person, or are registered in, in the case of a legal entity, an EU Member State or a third-party country with reciprocity. Following a recommendation by the MEE, the Council of Ministers may resolve to prohibit persons controlled by third (non-EU) countries for reasons of national security. Breach of this provision will result in the contractor forfeiting all of his rights under the agreement following a resolution of the Council of Ministers to this effect.

The duration of the exploration stage will be determined in the agreement, but may not exceed seven years for onshore areas and eight years for offshore areas, and may be extended by up to one half of the initial period under specific circumstances. If the contractor finds that the discovered deposit of hydrocarbons is commercially exploitable, he must notify the lessor, in writing, of the commercial exploitability of the deposit and the anticipated amount of its recoverable reserves. The decision as to whether the deposit is commercially exploitable rests with the contractor who must justify his decision in the notice. The duration of the production stage of each area is 25 years and may be extended for up to two, five year periods, on a proposal by the HHRM, when it can be proven that the original duration is not sufficient for the completion of the activities in question.

The contractor has the right, on the written consent of the lessor or employer and the approval of the MEE, to transfer, in whole or in part, his contractual rights and corresponding obligations to third parties or an affiliate enterprise. The latter is conditional on the contractor remaining wholly or jointly liable with the receiving affiliate for the performance of his contractual obligations. This consent and approval may be refused for reasons of national security or technical reasons.

The contractor will be subject to a special income tax of 20%, as well as to a regional tax of 5%, without any other ordinary or extraordinary contribution, fee, or other expenditure of any kind for the benefit of the State or of any third party. On expiration of the production stage of each exploration area, the same reverts, free and clear, to the State.

F. Renewable energy

F.1 Renewable energy

Further to the streamlining of the licensing procedures for RES projects by virtue of the New RES Law adopted in June 2010, Laws no. 4152/2013, 4685/2020 and 4951/2022 introduced additional measures to further expedite and simplify the licensing workstreams for RES projects. The two most recent laws above conclude the initiative of the State in its recent endeavour to simplify the applicable licensing process and ensure that the ambitious RES penetration targets are met. Law 4951/2022 also introduced the possibility of combining RES technologies with storage solutions and overhauled the national guarantees of origin system in alignment with Directive (EU) 2018/2001. Finally, Law 4964/2022 introduced a special framework for the development of offshore wind parks in the Greek territory.

In principle, a RES project must obtain a series of licences and execute specific regulated contracts, which can be classified in the following basic categories:

- Producer's Certificate;
- Environmental Licence;
- Binding Connection Terms Offer (CTO);
- Grid Connection Agreement;
- Direct or indirect Market Participation Agreements;
- Installation Licence; and
- Operation Licence.

In order to achieve greater cost-effectiveness and to incentivise better market integration of RES production, the State replaced the previous guaranteed feed-in-tariff (FiT) scheme, which provided electricity producers from RES a guaranteed sale price for the produced electricity, with a sliding Feed-in Premium ("FiP") scheme. This was in compliance with the recent European principles relating to state aid in the energy sector for the period 2014 to 2020 and, consequently, 2021 to 2025 (EEAG). The full implementation of the Target Model entails operating costs to RES producers such as, clearance and balancing and non-compliance charges, hence the State endeavours in the promotion of green PPAs for commercial and industrial participants.

Regarding long-term planning, each year the TSO publishes the National Transmission Development Plan (NTDP), presenting all planned transmission projects over a three-year horizon, as well as an overarching strategic view over a ten-year horizon, accounting for existing and prospect Producer's Certificates with an aim to plan the most suitable transmission projects to accommodate future RES production.

F.2 Renewable pre–qualifications

Under the applicable sliding FiP operating aid regime, eligible RES producers must participate in the RES Tenders in order to secure a FiP for the produced electricity. The pertinent eligibility criteria of RES stations are specified by RAE in respective calls for tenders. As per the terms of the RES Tenders conducted so far, in order to be eligible to participate in RES Tenders, RES Projects must have executed a Grid Connection Agreement with the competent operator or have acquired, at least, a final Connection Terms Offer. In September 2022, RAE performed the first RES Tender on the basis of the state aid scheme which was recently approved by the Commission for the period up to 2025.

F.3 Biofuel

Initiatives and developments on the biofuel market began in Greece in 2005, with biodiesel being the only biofuel produced in the country. Greece has also ratified relevant EU legislation[45] into domestic law, requiring the issuance of an administrative licence in order to perform certain activities, such as biofuel distribution. Biofuel distributors must first obtain a biofuel production licence or, alternatively, execute a valid biofuel purchase contract.

G. Climate change and sustainability

G.1 Climate change initiatives

To comply with its obligations under the 2020 Climate and Energy Package,[46] Greece has implemented a programme that coordinates all private and public sector activities with the aim of limiting greenhouse gas ("GHG") emissions. The update of Greece's plan, expected in early 2023 is set to include even more ambitious national targets. Greece has ratified the Paris Agreement under the United Nations Framework Convention on Climate Change by virtue of Law no. 4426/2016. Additionally, further to the National Climate and Energy Plan, the Government introduced the first National Climate Law in mid-2022 (Law 4936/2022), which provides a roadmap for the drastic reduction of GHG emissions in the next 30 years, setting ambitious targets for a reduction of 55% by 2030, 80% by 2040 in comparison to 1990, and achieving climate neutrality by 2050. The route to achieving these targets includes interventions in the sectors of electricity production (lignite phase out by 2028), transportation (promotion of EVs), industry, buildings, and waste management.

G.2 Emission trading

Ministerial decision no. 54409/2632/2004, as amended and codified in 2021[47] incorporates the rules of the EU Emission Trading System ("ETS") in implementation of the EU ETS Directive as amended and in force.

Greece participates in the European auction platform managed by EEX, under the provisions of the New EU ETS Directive. In this context, the RES and Guarantees of Origin Operator has been assigned by the MEE with the duties of the Auctioneer for Greece for the period up to 31 December 2020.[48]

G.3 Carbon pricing

See section G.2.

G.4. Capacity markets

Given the lack of a permanent solution and in the context of the commencement of the Target Model Markets, the Energy Law[49] provides for a Transitional Flexibility Remuneration Mechanism ("TFRM") for the provision of flexibility services to ensure the system's balancing due to the participation of RES. The flexibility service is defined as the rapid increase or decrease of the delivery or absorption of power from selected service providers, following relevant orders by ADMIE, the TSO. Providers must be able to respond within three hours of the issuance of a relevant order, to follow a rapid operating cycle, with a rate of change of power to increase or decrease the deliveries/absorption greater than or equal to 8MW per minute and ability to respond for at least three consecutive hours.

The process through which the service providers are selected includes the auction of the availability of power for the provision of flexibility services and is carried out by the TSO. Under the current regime the validity period of the TFRM lapsed on 31 March 2021.

H. Energy transition

H.1 Overview

The energy transition process in Greece is currently being carried out via:

- the establishment of Lignite Phase-Out Zones in the regions of Western Macedonia and Peloponnese;
- the simplification of the licensing framework for RES power plants;
- the support of natural gas, as the transitional fuel for decarbonisation; and
- the introduction of a special regulatory frameworks for the licensing and development of offshore wind parks and storage applications, in conjunction with the MEE's plan to promote innovative technologies, such as 'green hydrogen' solutions.

H.2 Renewable fuels

Hydrogen

The promotion of hydrogen applications via a special regulatory framework has been identified as one of the MEE's top priorities for the upcoming period, putting together a special task force mandated to produce a proposal for an appropriate licensing and regulatory framework for hydrogen-based applications. This includes the expansion of perspectives of gas infrastructure, renewables, maritime, and rail transportation, among other sectors.

H.3 Carbon capture and storage

The right to research, find, and store carbon dioxide ("CO_2") belongs exclusively to the State, exercising said right exclusively for the public interest.

In 2011, Ministerial Decision no. 48416/2037/E.103[50] introduced the legislative framework applicable to CO_2 capture and storage in geological formations in Greece, by specifying the more general provisions of Law no. 1650/1986. This ministerial decision specifies the rules and measures that must be adopted in order to secure environmentally safe CO_2 storage, thereby contributing to the European effort against the effects of climate change.

Research into the identification and selection of storage locations, and the storage of CO_2 in the relevant formations, can only be performed under the relevant licences granted to interested parties by the MEE.

H.4 Oil and gas platform electrification

On November 2020 Energean, which is the operator of the research license for the Prinos oil field, announced that it has reached an agreement with PPC for purchasing 100% of the electricity required for the relevant off-shore oil platform, as well as for its auxiliary on-shore infrastructure, from renewable energy sources.

H.5 Industrial hubs

There are currently 27 Industrial Areas in Greece, established in accordance with the provisions of Law no. 2545/1997, as amended and in force. The entity responsible for the management of Industrial Areas in Greece is ETVA Industrial Zones S.A. Under the provisions of Law no. 2545/1997, as well as Law no. 3982/2011, among other incentives, Industrial Areas are to provide security with regard to the applicable zoning and land ownership framework, as well as a well-developed infrastructure network. In August 2022, a draft Law was set in public consultation which will introduce the updated framework for Industrial Areas and Business Parks.

H.6 Smart cities

The city of Trikala is considered the first smart city in Greece. On its own initiative, Trikala introduced various smart systems including a smart lighting system and managing municipal street lighting. The introduction of these measures has, according to local authorities, resulted in significant energy savings. State-wide initiatives include a recently announced programme which involves the digital transformation of municipalities to be funded for the development of a wide range of digital services including smart parking solutions, cyber security, and digital transformation.

I. Environmental, social and governance (ESG)

The ATHEX SA has participated in the United Nations' Sustainable Stock Exchanges platform since 2018, promoting sustainable investments. A significant shift towards RES investments is also currently underway in Greece. Many industrial consumers focus on sustainable energy through the GOs scheme. The significance of environmental, social, and governance issues in energy companies is also growing and HEnEx, in collaboration with the Centre for Sustainability and Excellence, recently announced the ten best-performing energy companies in Greece in terms of ESG.

Endnotes

1. These laws are: Law no. 2773/1999 on the liberalisation of the Electricity Market; Law no. 3175/2003 which amended Law no. 2773/1999; the Grid Control and Power Exchange Code for Electricity of May 2005 ("Grid Code"); Law no. 3426/2005 on the Acceleration of Electricity Market Liberalisation; Law no. 3468/2006 on the Production of Electrical Energy from Renewable Energy Sources; Law no. 3851/2010 on the Acceleration of the development of RES and the Climate Change ("New RES Law"); Law no. 4001/2011 on the Operation of the Electricity and Natural Gas Energy Markets and for the Research, Production and Transmission Networks for Hydrocarbons and other provisions ("Energy Law"); Law no. 4389/2016 regarding the NOME auctions and implementation of Ownership Unbundling; Law 4414/2016 on the New RES and Combined Heat and Power ("CHP") Support Scheme; Law no. 4425/2016 regarding the new operational model of the wholesale electricity market in Greece; Law no. 4512/2018 ("Target Model Law"); Law no. 4951/2022 regarding the Modernisation of the RES Licensing Process – Phase B', Licensing of Electricity Production and Storage, Framework for the Development of Off-shore PV Stations and Special Provisions for Energy and Environmental Protection; and Law no. 4986/2022 on the transposition of Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU.
2. As of Law no. 4389/2016, the Greek State adopted the ownership unbundling model, ie FOU. Within this framework, and following an international tender which took place in 2016, the Chinese company State Grid International Development Ltd was selected as the Preferred Strategic Investor for the sale and transfer of a 24% state in the TSO; closing occurred in mid-2017. Following the full implementation of the FOU model, PPC fully divested its participation interests in the TSO.
3. See Article 118 §1 of Law no. 4001/2011, replaced by Article 98§ 5 of Law no. 4512/2018.
4. Under Article 9 Law no. 4425/2016, as adopted by Articles 78 and 80 Law no. 4512/2018 and Articles 117A, 117B, 117C Law no. 4001/2011 added by Article 96 Law no. 4512/2018.
5. See Article 117B Law no. 4001/2011, as same is supplemented by Article 96 Law no. 4512/2018.
6. Under Article 9 §1 Law no. 4425/2016, as supplemented by Article 83 Law no. 4512/2018.
7. Under Article 16 §1 in combination with Article 15 §1 Law no. 4425/2016, as amended by Article 87 Law no. 4512/2018.
8. See Article 44 et seq. Law no. 4843/2021.
9. The Electricity Regulation and the Regulation on Market Coupling.
10. In particular with the following: ACER Regulation, Electricity Regulation, REMIT, MiFIR and, subsequently, Regulation on Market Coupling. The fundamental rules regarding the Target Model have been introduced by the Electricity Regulation, which also introduces the rules for the cross border exchanges of electricity and the introduction of a fair mechanism for the compensation of the cross border electricity flows. The Market Coupling Regulation leans towards the unification of the national electricity markets at the European level establishing a guideline on capacity allocation and congestion management.

11. RAE decision no. 1116/2018 Government's Gazette Issue B' 5914/2018.
12. RAE decision no. 1125A/2019, Government's Gazette Issue B' 428/2020.
13. RAE Decision no. 1090/2018, Government's Gazette Issue B 5910/31.12.2018.
14. RAE Decision no. 943/2020, Government's Gazette Issue B 3076/24.07.2020.
15. See Article 7§2 A Law no. 4425/2016, as amended by Article 77 Law no. 4512/2018.
16. New Article 12§1 Law no. 4425/2016, as supplemented by Article 83 Law no. 4512/2018.
17. See Article 12§1 Law no. 4425/216, as amended by Article 83 Law no. 4512/2018.
18. RAE decisions nos. 1125/2019, Government's Gazette B' 428/2020 and 943/2020, Government's Gazette B' 3076/2020 respectively.
19. See new Article 12§1 b' as supplemented by Article 83 Law no. 4512/2018.
20. Under Article 15 Law no. 4425/2016, as introduced by Article 86 Law no. 4512/2018.
21. See MiFID II.
22. 22 The licence is examined based on the requirements of Law no. 3606/2007 and the EMIR.
23. See Article 117C Law no. 4001/2011 as added by Article 96 Law no. 4512/2018.
24. RAE decision no. 1116/2018, Government's Gazette B' 5914/31.12.2018, as amended and in force.
25. See Articles 10§8 and 18§2 Law no. 4425/2016, as amended by Articles 81 and 90, respectively of Law no. 4512/2018.
26. RAE decision no. 1090/2018, Government's Gazette B' 5910/31.12.2018, as amended and in force.
27. See Articles 12§13, 13§2, 18§3 Law no. 4425/2016, as supplemented by Articles 83, 84 and 90 Law no. 4512/2018.
28. See Article 12§1 Law no. 4425/2016, as added by Article 83 Law no. 4512/2018.
29. See Article 12§13 Law no. 4425/2016, as added by Articles 88 Law no. 4512/2018.
30. See Article 118A Law no. 4001/2011, as introduced by Article 97 Law no. 4512/2018.
31. Adopted by RAE's decision no. 509/13.06.2018 and published in Government Gazette B' 2307/18.06.2018, as amended and in force.
32. Introduced by RAE by virtue of its decision no. 340/2014, issued at Government Gazette B' 1778/2014.
33. Introduced by RAE by virtue of its decision no. 495/2021, issued at Government Gazette B' 2792/2021.
34. Approved by RAE by virtue of its decision no. 1431/2020 issued at Government Gazette B' 4760/B/2020.
35. Other ancillary requirements prescribed by the general legislation relate to building permits, health and safety legislation, etc. The issuance of these run in parallel and is a prerequisite to the licences mentioned above.
36. See Government Gazette B' 2940/05.11.2012.
37. Directive 2014/94/EU of the European Parliament and of the Council of 22 October 2014 on the deployment of alternative fuels infrastructure Text with EEA relevance.
38. See Article 88 Law no. 4512/2018.
39. Introduced through the amendment of the Energy Law by virtue of Law no. 4602/2019.
40. On 19 April 2018, the Hellenic Republic Asset Development Fund ("TAIPED" as per its Greek initials) selected the consortium composed by Snam SpA, Enagás Internacional SLU and Fluxys SA, named Senfluga Energy Infrastructure Holdings Société Anonyme as preferred investor for the acquisition of a 66% stake in DESFA, ie 31% from HRADF and 35% from Hellenic Petroleum SA. The transaction was closed on 20 December 2018 following DESFA's recertification as TSO under the OU scheme.
41. Directive 2009/73/EC.
42. Revised by RAE through its decision no. 1434/2020 (Government's Gazette B' 4801/2020).
43. Revised by RAE through its decision no. 421/2021 (Government's Gazette B' 3727/2021).
44. Ministerial Decision no. 178065/08.08.2018 GG issue B 3430/2018.
45. Biofuel Directive.
46. See www.ec.europa.eu/clima/policies/strategies/2020_en.
47. Under Ministerial Decision no. 105040/2297/2019, Government Gazette B' 4315/2019).
48. Ministerial Decision no. 11017/24.07.2018 GG issue B 3173/2018.
49. Article 143D as amended by Article 129 of Law no. 4685/2020 and Ministerial Decision ΥΠΕΝ/ΔΗΕ/66754/810/09.07.2020 (Government Gazette B' 2852/2020).
50. Published in Government Gazette B' 2516/2011.

Energy law in Hungary

Recent developments in the Hungarian energy industry

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Continuing "Solar Boom"

The National Energy and Climate Plan ("NECP"), adopted in February 2020, envisages a changed electricity generation mix that builds extensively on nuclear and solar energy. Hungary is expected to meet its climate protection undertakings by, among other things, boosting photovoltaic ("PV") generation with expectations of achieving an installed solar capacity of 6,500MW by 2030. As of April 2022, the gross amount of inbuilt renewable energy source ("RES") generation capacities has exceeded 3,000MW (from the level of 668MW registered in 2018). Most new installations are subsidised through the feed-in-tariff ("FiT") or mandatory off-take regime while the new METÁR (an abbreviation for the Subsidy Scheme on the Offtake of Electricity Generated from Renewable or Alternative Energy Sources) or contract for difference ("CfD") Regime is also gaining ground. RES Generators under METÁR are exposed to a more market-based regime whereby RES Generators are selling the generated electricity on the free market; however, subject to the outcome of regular open tenders, a certain surplus (premium) may be awarded to RES Generators as a state subsidy to ensure returns on investments. Within the framework of this new subsidy scheme, the off-take of subsidised prices has decreased significantly.

Reform of grid connection allocation

The rapid growth of new solar power plants has led to the saturation of the electricity grids, resulting in a major reform concerning grid connection allocation. Under the amended system, every six months grid operators must publicise detailed information about free capacities and the technical and foreseeable economic conditions of connection. Additionally, grid connection applicants must pay financial guarantees for taking part in the capacity allocation. The available feed-in capacities are then allocated under competitive principles or, in the absence of further capacities, based on individual grid connection offers.

COVID-19 FDI screening regime

In addition to the already existing permanent foreign direct investment screening ("FDI") rules, a new FDI regime came into force in May 2020. Under the COVID-19 FDI regime, investments in strategic fields of industries (including the energy sector) are subject to prior review and acknowledgement by the competent Hungarian minister. The main purpose of the regime is to protect the Hungarian enterprises in strategic sectors from excessive foreign takeovers and to safeguard national interests. This means that Hungarian FDI rules now cover investors from both outside and within the European Union ("EU"), the EEA and Switzerland.

Guarantees of origin market changes

As of 1 January 2022, the Guarantees of Origin ("Guarantees") for RES Generators participating in the feed-in-tariff regime ("FiT Regime") are no longer given to the generators and must be sold by MAVIR ZRt ("MAVIR") at auction on the Hungarian Guarantees of Origin market which will be operated by the Hungarian Power Exchange ("HUPX") from June 2022 ("HUPX GO"). In the first phase of the operation of the HUPX GO, MAVIR, as the nominated buyer of Hungarian FiT production, will be the only seller of Guarantees in quarterly auctions. Alternately, the buyer side is open to energy traders, end-users and other market participants.

Overview of the legal and regulatory framework in Hungary

A. Electricity

A.1 Industry structure

General

The current structure of the Hungarian market was primarily established in the mid-1990s when the majority of large power plants, public utility suppliers and the distribution networks were privatised. However, since 2010 the Hungarian Government ("Government") has significantly increased the Hungarian presence on the market through acquisitions, eg the acquisition of electricity distribution system operators ("DSOs"), natural gas DSOs, electricity generators as well as electricity and natural gas retailers (universal service providers) from the subsidiaries of RWE, EDF (Engie), ENI and E.ON, respectively.

Presently, domestic power plants sell the majority of their power generation through framework contracts to the universal service providers and through bilateral contracts to traders. A significant part of the primary purchases of traders goes through a secondary trade within the trading sector before reaching final customers or export markets. Imports also play an important role in the Hungarian electricity supply.

The Hungarian electricity market is comprised of several participants: energy generators, the Transmission System Operator ("TSO"), the regulated market operator, DSOs, suppliers' storage operators, etc. Hungary has implemented the 'balance group model'. A balance group is a virtual group of suppliers and customers within which energy production and supply is balanced. While each market participant must be a member of a balance group, energy suppliers and traders may decide whether they join an existing balance group or initiate their own one.

Nature of the market

The implementation of the European Union ("EU") electricity related legislative packages has gradually liberalised the Hungarian electricity market. The entry into force of Act LXXXVI 2007 on electricity (the "Electricity Act") and the related secondary legislation has ended the public sector utility segment of the market with its state-set electricity prices. Since the Electricity Act, electricity prices have been liberalised, although some restrictions still apply.

Key market players

MAVIR, a member of the state-owned MVM Group, is the only Hungarian electricity TSO. One of the MAVIR affiliates, HUPX Zrt., is the operator of the Hungarian Power Exchange ("HUPX").

The electricity distribution systems are operated by six regional DSOs. Three of them (E.ON Dél-dunántúli Áramhálózati Zrt., E.ON Észak-dunántúli Áramhálózati Zrt. and ELMŰ Hálózati Kft.) are vertically integrated subsidiaries of E.ON Group. Two DSOs (MVM Émász Áramhálózati Kft. and MVM Démász Áramhálózati Kft.) are owned by MVM Group, while OPUS TITÁSZ Áramhálózati Zrt. is a member of the OPUS Group.

MVM Group is also the most important player on the electricity generation market. It operates the Paks nuclear power plant (2000MW), the lignite-fired Mátra power plant (950MW) as well as several other fossil-fueled units and power plants using RES throughout Hungaria. Another key player is the MET Group with its flagship facility, the gas-fired Dunamenti power plant. E.ON and Alpiq also own generation units operating in Hungary. Due to a large increase in solar energy generation in recent years, the gross installed capacity of solar power plants in Hungary has exceeded 3000MW, bringing a high number of smaller stakeholders into the market.

Regulatory authorities

The Hungarian Energy and Public Utility Regulatory Authority (*Magyar Energetikai és Közmű-szabályozási Hivatal*) ("HEA") is the chief public administrative authority for regulating and supervising the energy industry in Hungary. Among other things, the HEA's responsibilities include: issuing licenses, approving the general terms and conditions of the licensees, approving changes in the shareholder structure of the licensees and consenting to dispose of certain material assets of the licensee. All licensees must pay a yearly supervisory fee to the HEA.

In energy-related matters, the primary governmental authority is the Ministry of Technology and Industry.

Legal framework

The Electricity Act and the relevant secondary legislation adopted by the Government are the backbone of the applicable legislative framework. HEA is vested with derivative legislative powers and is entitled to adopt decrees in certain limited areas (eg grid connection fees).

Although not an authority in the legal sense, MAVIR, as Hungary's TSO, also plays a significant role as a market regulator. MAVIR is responsible for dispatching networks by managing balance circles and schedules. MAVIR's Commercial Code (*Kereskedelmi Szabályzat*) and Operational Code (*Üzemi Szabályzat*), as approved by the HEA, provide guidance to the market in this regard, and are applied in practice as by-laws of the electricity market. Similarly, the shared Distribution Code (*Elosztói Szabályzat*) of the DSOs, as approved by the HEA, provide the detailed rules concerning the access to electricity supply for end consumers (the relevant codes of the TSO and the DSO are hereinafter "Electricity Codes").

Implementation of EU electricity directives

The EU's Third Electricity Directive has been fully implemented in Hungary. On the basis of the Hungarian legislator's decision, the independent transmission operator ("ITO") model was used with MAVIR. The ITO model requires the ownership rights to the transmission system, and the operation activity thereof, to remain within the framework of a vertically integrated undertaking. Therefore, the implementing acts introduced a comprehensive and detailed set of unbundling rules to ensure the independence of the ownership and operation of the transmission system from generation and supply or trading activities.

A.2 Third party access regime

Third party access

Under the Electricity Act, the TSO and the DSOs ("Grid Operators") open the transmission and distribution networks they control to network users. The conditions to access these transmission and distribution networks may not:

- be discriminatory;
- provide grounds for abuse;
- contain unreasonable restrictions; or
- jeopardise the security of supply and the quality of services.

The TSO or DSOs may only refuse access or limit, reduce or suspend contracted supplies in an objective, transparent and non-discriminatory manner.

Service may be limited, reduced or suspended in advance or during the operation of the electricity system in the event of extraordinary network conditions, imminent danger of life or property, etc.

Network connection

Grid Operators must publish general terms and conditions ("GTC") and conclude agreements under the GTC with end users and generators, providing for their connection to the grid. The content of the grid operators' GTCs is primarily determined by the Electricity Codes. Grid users must connect their facility to the DSO operating in their respective service territory.

Until recently, developers were able to secure grid connection for new power plants using a relatively simple and unrestricted procedure. This meant that almost any developer requesting grid access and feed-in-capacity for a new power plant had received a binding offer from the competent Grid Operator setting out the financial and technical conditions of installing the connection and containing fairly reasonable terms on connection fees and timing. However, mostly because of the rapid development of solar power plants, the power grids have become saturated, and the grid operators have initiated the review of the applicable legislation. Due to the above, new and competitive capacity allocation principles were introduced in the Electricity Act, bringing conceptual changes to the previous system.

Under the new regime, which is applicable to capacity requests submitted after 3 May 2022 (no new grid connection request could be submitted under the transitional period lasting from July 2021 until May 2022), Grid Operators must make detailed information about free capacities public, broken down by high-voltage and high or medium-voltage transformer stations, and the technical and foreseeable economic conditions of connection, every six months. This is to facilitate the power producers' (both in cases of generation units using renewable and conventional energy sources) access to the public grid, awarded primarily through competitive tenders. On the other hand, grid connection applicants must pay financial guarantees for taking part in the capacity allocation (HUF900,000 + HUF3,600,000/MW) as an advance payment (partially or entirely) covering grid connection costs.

Within the framework of the first capacity publication on 3 May 2022, the Grid Operators stated that 0MW grid connection capacity is available for power plants and that there is also 0MW grid connection capacity available for weather-dependent power plants in the following six months. Thus, there was no tender procedure at this time where producers may have applied for grid connection capacities on predetermined terms (eg concerning grid connection costs or availability dates) and without additional technical requirements.

Nevertheless, developers are entitled to initiate individual procedures where they may be offered grid capacity on individual (and most likely unfavourable) terms established by the Grid Operators.

A.3 Market design

The Hungarian electricity market is fully liberalised. Currently, the free choice of energy supplier applies to every consumer, although the prices of universal suppliers are still regulated. New generation capacities may be set up by any person at their own business risk, with the exception of wind farms. The wholesale trade of electricity may take place on HUPX or on the basis of over-the-counter ("OTC") agreements. The market penetration of corporate power purchase agreements ("PPAs") is rising but is still relatively low.

A.4 Tariff regulation

As aforementioned, the price of electricity supply is no longer regulated, save for the price of electricity supplied in the framework of universal service, the one-time connection fee payable to the Grid Operators for installing a connection point in order to cover the necessary network development costs, and the network usage fees payable by network users for the use of the system.

Universal services

Universal services must be provided under fair, clearly comparable and transparent pricing mechanisms, primarily for residential customers and small and medium enterprises ("SMEs"). The price for universal services is determined on the basis of comparative analyses and prevailing market prices and shall be sufficient to cover the justified and reasonable operating expenses of efficient authorised operators, with a view to enforcing the lowest cost principle.

The price for mandatory universal services provided by universal service provider licensees, the conditions for charging such prices and the framework of price regulation, and the scope of some relevant services provided for special fees are decreed by the Minister of Technology and Industry (currently 4/2011. (I.31.) NFM Decree) on the basis of recommendations by the HEA.

Network usage fees

Under the Electricity Act, the network users should pay multiple fee elements including transmission and distribution fee elements for the use of the Hungarian electricity system. Together, these fee items are known as 'network usage fees' and the rates and the conditions of charging such fees are the same throughout the country. The network usage fees must be transparent, proportionate and non-discriminatory. The fees should be regulated by the lowest cost principle, so the justified and reasonable operational expenses may be adhered to.

Network usage fees are set each year within the framework of multiannual price regulation cycles; the current cycle lasting from 1 April 2021 until 31 December 2024. The price setting is primarily regulated by the Electricity Act and the decree of the HEA (most notably HEA Decree 10/2016 (XI.14.) and HEA Decree 12/2020 (XII.14.)) Components of the respective network usage fees, the principles and the regulatory framework for determining and regulating network usage fees are determined by the HEA by way of adopting a decree until 15 May of the year preceding the upcoming price regulation cycle. The HEA decree setting forth the actual amount of network usage fees must be published at least 45 days before it enters into force.

A.5 Market entry

Authorisations

The below activities may be carried out by entities who comply with and hold the appropriate licence issued by the HEA:

- small power plant with a nominal generation capacity of at least 0.5MW but less than 50MW: combined (establishment and operation) small power plant license;
- power plant with a nominal generation capacity of 50MW or more: its establishment, generation of electricity from the plant or its expansion, the increase or decrease of its nominal generation capacity (to an extent set out in other specific legislation), the suspension or termination of electricity generation or the decommissioning of the power plant;
- transmission system operation;
- the distribution of electricity;
- electricity trading;
- the provision of universal services;
- the operation of the regulated electricity market;
- the implementation, expansion and termination of private lines (*magánvezeték*) and direct lines (*közvetlen vezeték*);
- operating public light fixtures, excluding the light fixtures of the public lighting distribution network;
- recharging of electric vehicles ("EVs"); and
- the operation of an electricity storage facility with a nominal output capacity of 0.5MW or more.

Licensing regime

The applications for the licenses of the HEA are to be made on a specific form accompanied with the documents indicated in the Electricity Act and its implementation decree. The HEA shall issue the licenses if the application is in compliance with the requirements set forth by law.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The supply of electricity for household consumers and certain SMEs receiving low voltage electricity, with a connection capacity not exceeding 3x63A together for all service locations, falls within the category of universal services. In addition, certain public or governmental entities, state budgetary institutions and organs of local municipalities providing public services may ask the universal service provider to be serviced within the framework of the PSOs under the conditions (eg price or contractual terms) of the universal service.

Smart metering

As part of the introduction of intelligent metering systems, and for the purpose of carrying out related assessments, authorised network operators conducted pilot projects relating to the use of smart meters under the supervision of the HEA. Users were required to cooperate on the implementation of these pilot projects and to allow the installation of smart meters.

As of 1 January 2020, the Electricity Act prescribes the obligatory installation of smart meters in the case of, among other things, new network connections with a capacity of less than 3x80A and existing network connections with an annual consumption exceeding 5000kWh. In other cases, the consumer is entitled to request the installation of smart meters; the DSO must carry out such requests within four months.

Electric vehicles

In Hungary, only EVs and externally charged hybrid EVs that are, according to the official documents, capable of covering at least 25km in electric mode, constitute EVs and thus as 'environmentally friendly vehicles'. Although since the beginning of 2021 the ownership of electric cars has grown from 28,000 to almost 48,000, the share of battery EVs in the total stock of cars and vans in Hungary was only 0.3% in 2021, a figure that is significantly below the share of northern and western EU countries.

Currently, subsidies for the purchase of new electric cars are available on a grant basis as well as in the form of tax advantages (in terms of registration tax, vehicle tax, company car tax and transfer duty). The provisions on encouraging the use of electric cars include the obligation to install at least one electric charging point in non-residential buildings that are newly built or undergoing major renovation and have more than ten parking spaces. It is also mandatory to install charging points for shops with a net sales area of more than 300m2 in municipalities with a population of more than 50,000 inhabitants. Another advantage of electric cars is free parking in certain municipalities.

A.7 Cross-border interconnectors

The Electricity Act prescribes that only the electricity lines operated by the TSO may cross state borders. The following cross-border interconnectors exist between Hungary and its neighbours:

- Göd – Levice (Slovakia) (400kV);
- Győr – Gabčikovo (Slovakia) (400kV);
- Sajóivánka – Rimaszombat (Slovakia) (400kV);

- Gönyű – Nagygyőröd (Slovakia) (400kV);
- Albertirsa – Zakhidnoukrainska (Ukraine) (750kV);
- Kisvárda – Mukačevo (Ukraine) (220kV);
- Sajószöged – Mukačevo (Ukraine) (400kV);
- Tiszalök – Mukačevo (Ukraine) (220kV);
- Békéscsaba – Nadab (Romania) (400kV);
- Sándorfalva – Arad (Romania) (400kV);
- Hévíz – Zerjavinec (Croatia) (400kV);
- Paks – Ernestinovo (Croatia) (400kV);
- Sándorfalva – Subotica (Serbia) (400kV);
- Győr – Wien Südost (Austria) (400kV);
- Győr – Neusiedl (Austria) (220kV);
- Győr – Wien Südost (Austria) (220kV); and
- Cirkovice – Hévíz (Slovenia) (400kV).

Cross-border supplies must be notified to the TSO via the submission of an operating schedule. This is the responsibility of the relevant balancing circle representative (*mérlegkörfelelős*) (the "BCR") of the balancing circle which the trader has joined (or the trader itself if it has established an individual balancing circle).

The available transmission capacities on border crossing points are determined by the TSO with regard to: Regulation (EC) No. 714/2009 of the European Parliament and of the Council on conditions for access to the network for cross-border exchanges in electricity; and the Electricity Codes.

The TSO must publish its forecast for the available transmission capacities for the following 12 months on its website and, in the case of line bottlenecks, the TSO organises capacity auctions on the basis of its agreement with the TSOs of neighbouring countries. The auctions may be organised for specific time periods (eg yearly, monthly, weekly and daily).

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

The Hungarian oil supply mainly consists of imports from the Russian Federation through the Friendship (*Druzhba*) pipeline. Another important route is through the Adria pipeline starting from the Omisalj Oil Terminal, Croatia. The two pipelines are crossing at the Dunai Oil Refinery in Százhalombatta, Hungary. The refinery and the Hungarian sections of the above pipelines are operated by the MOL Group.

Oil is considered a state-owned mineral resource under the Act CXCVI on National Assets. Therefore, the Hungarian State has the right to search, explore and produce oil. The Hungarian State is authorised to transfer the exercise of these rights to individuals or legal entities, based on mining law, that have the necessary technical and financial means for the establishment and operation of such mining activities.

Key market players

The MOL Group, with more than 950 producing wells (oil and gas), accounts for almost 80% of Hungary's hydrocarbon production. Production is concentrated to South and East Hungary.

The MOL Group's Dunai Oil Refinery is one of the largest refineries in the Central and Eastern European region with a refining capacity of 165,000 barrels per day (8.1 million tonnes per year).

Regulatory authorities

As of 1 January 2022, the main authority in charge of regulating and supervising mining activities and issuing mining related permits is the Supervisory Authority for Regulated Services (*Szabályozott Tevékenységek Felügyeleti Hatósága*) ("Mining Authority") as a general legal successor of Mining and Geological Survey of Hungary (*Magyar Bányászati és Földtani Hivatal*).

Legal framework

Mining activities, among them oil exploitation from a deeper zone of the Earth's crust underneath the depth of 2,500 metres, are primarily regulated by Act XLVIII of 1993 on mining ("Mining Act") and its implementation decree.

Areas designated for mining underneath 2,500 metres qualify as 'closed areas'. The prospection, exploration and exploitation of such deep underground 'closed areas' is only permitted under a concession granted by the Hungarian state in a public tender under a concession agreement.

Gas

Nature of the market

Since the enactment of Act XL of 2008 on natural gas supply (*a földgázellátásról szóló törvény*) ("Natural Gas Act"), and subsidiary legislation such as Governmental Decree No. 19/2009 (I.30) on the implementation of the Natural Gas Act, the Hungarian natural gas sector has been fully liberalised, with former public utility suppliers being replaced by universal service providers. Market prices are now subject to the agreement of the parties except for universal services and network usage fees.

Hungary is an importer of natural gas, with the majority of gas arriving from Russia under long-term natural gas supply agreements. Hungary is connected to the international gas markets by, among others, the Fraternity (*Testvériség*) Pipeline from Russia, and the HAG pipeline from Austria. Interconnectors are also operational, crossing the Romanian, Serbian, Slovakian and Croatian borders.

The wholesale trade of gas may take place with bilateral contracts (OTC) or on the Central Eastern European Gas Exchange ("CEEGEX").

Key market players

The TSO in the Hungarian natural gas market is Földgázszállító Zrt. ("FGSZ"), a subsidiary of the MOL Group. At present, there are six major DSOs and two natural gas storage licensees operating in the market with MVM Group, E.ON group and OPUS Group being the operators of such infrastructure.

In terms of both the upstream and downstream markets, MOL Group is the dominant market player.

Regulatory authorities

The natural gas market is primarily regulated by the HEA. The HEA's responsibilities include: licensing the natural gas market, approving the general terms and conditions of the licensees, approving changes in the shareholder structure of the licensees, and consenting to dispose of certain material assets of the licensee. All licensees must pay a yearly supervisory fee to the HEA.

The Mining Authority is responsible for regulating mining activities, supervising the implementation of mining concessions and overseeing the construction and operation of natural gas pipelines.

In energy-related matters, the main governmental authority is the Ministry of Technology and Industry.

Legal framework

The Natural Gas Act and the relevant secondary legislation adopted by the Government is the backbone of the applicable legislative framework. HEA is vested with derivative legislative powers and is entitled to adopt decrees in certain limited areas (eg grid connection fees).

Although not an authority in the legal sense, the TSO still plays a significant role as a market regulator. The TSOs Commercial and Operational Code (*Üzemi és Kereskedelmi Szabályzat*), as approved by the HEA, provides guidance to the market and is applied in practice as a by-law of the natural gas market.

Implementation of EU gas directives:

The Third Electricity Directive was fully implemented in Hungary. On the basis of the Hungarian legislator's decision, the ITO model was with FGSZ. The ITO model requires the ownership rights to the transmission system, and the operation activity thereof, to remain within the framework of a vertically integrated undertaking. Therefore, the implementing acts introduced a comprehensive and detailed set of unbundling rules to ensure the independence of the ownership and operation of the transmission system from generation and supply or trading activities.

B.2 Third party access regime to gas transportation networks

Authorised system operators (ie the TSO, the DSOs and the gas storage operators) must make available any free capacity of the transmission and distribution pipelines, and the storage facilities they operate, to network users for consideration. Under the Natural Gas Act, 'network user' means a customer (eg a natural gas trader) who has access to the transmission or distribution pipeline or the natural gas storage facility for the purpose of injecting into or withdrawing natural gas under a capacity contract.

The conditions of access must be non-discriminatory and must not provide grounds for abuse, contain unjustified restrictions or jeopardise the security of supply and the quality of services. Authorised system operators must hold negotiations on the available capacity at the connection points of transmission and distribution pipelines, and the storage facilities they operate, and must make public the resulting capacity data following such negotiations.

The purchased capacity related to a connection point at a service location qualifies as a right with pecuniary value. If the service location or connection point is transferred to a third party, the available capacity is transferred automatically to the relevant third party.

B.3 LNG terminals and storage facilities

There are two gas storage licenses in the Hungarian natural gas market. These are held by HEXUM Földgáz Zrt. (former name: MMBF Zrt.), a subsidiary of the Hungarian Hydrocarbon Stocking Association, and Magyar Földgáztároló Zrt. (former name: E.ON Földgáz Storage Zrt.), a subsidiary of the state-owned MVM Zrt.

Magyar Földgáztároló Zrt. has four underground natural gas storage sites where gas is stored in depleted gas fields. The underground storage sites are located in Zsana, Hajdúszoboszló, Pusztaederics and Kardoskút, with a total annual working gas capacity of 4.2 billion cubic metres ("bcm"). The gas storage of HEXUM Földgáz Zrt is located in Algyő with a total working gas capacity of 1.9bcm.

B.4 Tariff regulation

Universal services

Universal services must be provided under mandatory, fair, clearly comparable and transparent pricing mechanisms, primarily for residential customers and SMEs. The price for universal services is determined on the basis of comparative analyses and prevailing market prices and shall be sufficient to cover the justified and reasonable operating expenses of efficient authorised operators, with a view to enforcing the lowest cost principle.

The price for mandatory universal services provided by universal service provider licensees, the conditions for charging such prices and the framework of price regulation, and the scope of some relevant services provided for special fees are decreed by the Minister of Technology and Industry (currently 69/2016. (XII.29.) NFM Decree) on the basis of the recommendations by the HEA.

System usage fees

The regulatory framework and the general rules of application of the system usage fees are laid down in the Natural Gas Act and the relevant decrees of the HEA. The annual rates of system usage fees are determined by the HEA, in compliance with the preliminarily set multiannual cycle price regulation principles. The current cycle lasts from 2021 until 2025 and is primarily regulated by HEA Decree 8/2020 (VIII.14.). The actual system usage fees are determined by the individual resolutions issued by the HEA to the system operators.

System usage fees must be transparent, proportionate and non-discriminatory. A system usage fee consists of transmission system related charges, fees for the distribution of natural gas, the fee for the storage of natural gas, and transmission system control fees.

The rates of system usage fees are determined either in a way that covers the capital invested and the justified and reasonable operating expenses of authorised operators, or on the basis of comparative analyses in accordance with the principle of minimum cost, in order to promote the improvement of the quality of services rendered by the operators and the security of supply.

B.5 Market entry

As a general rule, a new entrant must obtain a licence from the HEA in order to become a market participant in the Hungarian natural gas market. Under the Natural Gas Act, the following activities can be pursued with the possession of the relevant licence issued by the HEA:

- operation of the transmission system;
- distribution of natural gas;
- storage of natural gas;
- trading of natural gas;
- providing universal services;
- operation of a regulated natural gas market;
- restricted trading of natural gas;
- installation of direct pipeline (*célvezeték*); and
- supply of propane-butane gas.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The supply of natural gas for household consumers and certain SMEs falls within the category of universal services. In addition, certain public or governmental entities, state budgetary institutions and organs of local municipalities providing public services may ask the universal service provider to be serviced within the framework of the PSOs under the conditions (eg price or contractual terms) of the universal service.

Smart metering

Hungary does not currently have any developments regarding smart meters.

B.7 Cross-border interconnectors

The cross-border interconnectors and relevant TSOs are:

- Beregdaróc/Ukrtansgas (Ukraine);
- Mosonmagyaróvár/OMV Gas (Austria);
- Kiskundorozsma/Srbijagas (Serbia);
- Kiskundorozsma 2/Srbijagas (Serbia);
- Csanádpalota/Transgaz (Romania);
- Drávaszerdahely/Plinacro (Croatia); and
- Balassagyarmat/Eustream (Slovakia).

Network users are entitled to contract capacities at border crossing points according to the allocation mechanisms set out in the specific legislations (eg Hungarian and Austrian in case of the Mosonmagyaróvár/OMV Gas interconnector). Network users may also resell any unused capacity that they have at the border crossing points subject to prior notice to the relevant authorised system operator.

Network users must announce which cross-border capacities they intend to contract in the next gas year (beginning 1 October of each calendar year and ending 30 September of the following calendar year) to the TSO, in the form of a binding declaration of intent. In the case of an over-subscription for border crossing point capacity (ie the claimed capacities exceed the published free capacities) for border crossing points, the TSO announces auctions yearly, monthly or daily.

C. Energy trading

C.1 Electricity trading

Under the Electricity Act, an electricity trading licence, which also entitles the licensee to supply electricity directly to end-users, may be granted to a Hungarian business association with a legal personality, or the Hungarian branch of a company established in any Member State of the EU or the EEA.

Imbalance regime, notifications to TSO

To trade electricity on the Hungarian wholesale market, the electricity dealer must join the Hungarian balancing circle system. The balancing circle (*mérlegkör*) is a reimbursement or settlement system designed to balance electricity supply and demand, carry out related functions and regulate related liabilities. The Hungarian balancing circle system consists of several balancing circles, each of which comprises a BCR and the balancing circle members. The BCR must conclude a balancing circle agreement with the TSO, while the members of the balancing circle conclude a balancing circle membership agreement with the BCR. The balancing circle is represented by the BCR in matters regarding the TSO.

The sale and purchase of the balancing energy must be announced to the TSO using a special scheduling system into which the schedules of the planned transactions should be submitted by the BCR.

Trading OTC, EFET agreements, trading on exchange

Once an electricity trader becomes a member of a balancing circle, they may execute wholesale trading in Hungary either through direct deliveries OTC or on the HUPX.

In contrast to electricity supply agreements governing supplies to end-consumers, agreements between electricity traders are not subject to any specific restrictions. Hence, framework agreements, such as those provided by the European Federation of Energy Traders (EFET) are regularly used in Hungary as standardised model agreements.

HUPX operates an electronic platform offering spot trading and a physical futures market. The products traded on the HUPX are standard contracts for the physical delivery of electricity within the Hungarian transmission system. The clearing and the settlement of the transactions made on the HUPX is performed by the European Commodity Clearing AG, the clearing house of all European Power Exchange (EPEX Spot) markets.

With the entry into force of MiFID II regulation, the first Hungarian financial energy exchange, HUDEX, was launched on 3 January 2018. HUDEX offers a Hungarian Financial Power Base Load and Peak Load Products as well as a Hungarian Natural Gas Base Load Product.

EU market coupling

On 11 July 2013, representatives of the national regulatory authorities (ERU, URSO, HEA, URE and ANRE), TSOs (CEPS, SEPS, MAVIR, PSE, and Transelectrica) and market operators and power exchanges (OTE, OKTE, HUPX, TGE, and OPCOM) from the Czech Republic, Slovakia, Hungary, Poland and Romania, signed the Memorandum of Understanding on cooperation with respect to Romania's and Poland's adhesion to the integrated day-ahead electricity markets of the Czech Republic, Slovakia and Hungary.

On 19 November 2014, the CZ-SK-HU-RO Market Coupling was successfully launched, integrating the Czech, Slovak, Hungarian and Romanian day-ahead electricity markets and replacing CZ-SK-HU Market Coupling.

The DE-AT-PL-4M MC, also referred to as Interim Coupling Project, successfully executed the coupling of the 4M MC (Czech Republic, Slovakia, Hungary and Romania) and Multi Regional Coupling (MRC) on 17 June 2021. Interim Coupling connected the borders of 4M MC with the Multi-Regional Coupling by introducing Net Transmission Capacity based implicit capacity allocation on six borders (PL-DE, PL-CZ, PL-SK, CZ-DE, CZ-AT, HU-AT), resulting in more favourable conditions for the day-ahead power market participants. The project parties involved in the day-ahead Core Flow-Based Market Coupling project (Core FB MC) announced the successful launch of the project on 8 June 2022. Flow-Based Market Coupling mechanism optimises day-ahead European electricity market for 13 countries: Austria, Belgium, Croatia, the Czech Republic, France, Germany, Hungary, Luxembourg, the Netherlands, Poland, Romania, Slovakia and Slovenia. The harmonised capacity calculation methodology makes the system more efficient and robust, thereby increasing the efficiency of the capacity allocation.

C.2 Gas trading

Under the Natural Gas Act, consumers may purchase natural gas from a gas trader, a natural gas producer up to the volume of such producer's own production levels, on the organised natural gas market, or by way of importing natural gas.

The Natural Gas Act does not determine the conditions that are required to constitute part of the gas purchase agreement between the purchaser and the seller. Some mandatory provisions of the Natural Gas Act, or the Operational and Commercial Code of the TSO, will automatically apply, even where not specifically incorporated into the individual contracts (such as the quality of gas, pressure figures, several technical and safety rules, metering of gas, etc). However, the commercial terms of such contracts (the term of the contract, the volume and price of the gas sold and purchased) are subject to the agreement of the parties.

Imbalance regime, notifications to TSO

The TSO is responsible for maintaining hydraulic balance in the transmission pipeline. Network users must provide for trade balance on a daily basis; to this end, network users must feed the amount of natural gas withdrawn on a given gas day from the transmission pipeline back into the transmission pipeline on the same gas day.

In the event of failure to restore trade balance, the network user will be liable for covering all imbalance charges arising as a consequence. The TSO and distributors of natural gas are liable to provide for hydraulic balance during the day in the transmission pipeline and the distribution pipeline they operate.

D. Nuclear energy

The only nuclear power plant in Hungary is located in Paks and has a gross installed capacity of 2,000MW. It is owned and operated by MVM Group. The Paks Nuclear Power Plant has played a key role in the Hungarian electricity supply since its commissioning in 1982. The installation's generation licenses are set expire between 2032 and 2037, however if deemed technically feasible, MVM Group may consider extending their licenses.

By way of an intergovernmental agreement signed between Hungary and the Russian Federation in 2014, Hungary committed itself to install two new nuclear power plant blocks with each having a capacity of 1,200MW. The future of the Paks II project, currently being developed by Russian state-owned Rosatom Corporation, has become uncertain due to the sanction packages adopted by the EU in February 2022. However, Prime Minister Viktor Orbán, after sworn in as Hungary's prime minister for the fifth time on 16 May 2022, highlighted that the new Paks nuclear reactors were key to national security and must be handled with high priority. It is intended that the nuclear reactors will be commissioned in 2030.

E. Upstream

Upstream activity is relatively limited in Hungary due to the low number of efficiently exploitable oil and gas fields.

Upstream activities may be pursued by domestic or foreign legal entities or private persons subject to a concession agreement concluded based on an open tender. The term of the concession agreement may not exceed a maximum of 35 years; however, this term can be extended once by an additional term that is equal to half of the original duration.

The extraction of natural gas and oil is subject to the payment of mining royalty as stipulated by the respective concession agreement.

F. Renewable energy

F.1 Renewable energy

Under the Clean Energy Package as adopted between 2018 and 2020, Hungary has committed to increase the share of RES in its gross energy consumption mix to 21% by 2030 and to net zero emissions by 2050. The NECP, adopted in February 2020, envisages a changed electricity generation mix that builds extensively on nuclear and solar energy while continuing to use fossil-based (mainly natural gas fueled) power plants to compensate for imbalances in the grid caused by weather-dependent energy sources.

Hungary is expected to meet its climate protection undertakings through the ongoing nuclear power plant development of 2,000MW new generation capacity at the existing Paks site, and through boosting PV generation which is expected to achieve an installed solar capacity of 6,500MW by 2030. As of April 2022, the gross amount of inbuilt RES generation capacities has exceeded 3,000MW (from a level of 668MW registered in 2018).

Regarding most of the RES Generators currently operational and under construction in Hungary, the primary incentive is the mandatory offtake or FiT Regime. Under this FiT Regime, the RES Generators ("FiT Generators") are entitled to sell generated electricity at predetermined and regulated prices for a certain period of time and up to a certain quantity as determined by HEA. In order to apply the FiT Regime, MAVIR established a so-called mandatory off-take or feed-in-tariff balance group ("FiT Balance Group") and operates it as balance group operator. FiT Generators become members of the FiT Balance Group and they receive remuneration for the electricity generated by them and sold through the FiT Balance Group by MAVIR, at regulated prices specified by the HEA. FiT Generators are not allowed to sell electricity to any third party while participating in the FiT Regime. The detailed rules of the FiT Regimes are provided by Government Decree 389/2007 (XII. 23.).

Since 1 April 2016, the entire quantity of electricity generated by FiT generators is sold by MAVIR on the HUPX. In order to maintain the FiT Regime, a specific fund has been introduced through legislation. The costs of the FiT Regime are financed by other balance group operators (electricity traders) in the ratio of electricity sold to end-users in their balance group not licensed for universal service provision. The financial burden of such a fund is ultimately shouldered by free market end users (ie primarily by industrial and commercial users).

The support system for RES Generators has been amended significantly as changes in the relevant EU legislation took effect. As a result, an application for participating in the FiT Regime could only be submitted until 31 December 2016. As of 1 January 2017, a new CfD or premium based renewable energy support scheme has been introduced ("METÁR Regime" or "Premium System"). RES Generators under METÁR are exposed to a more market-based regime whereby RES Generators are selling the generated electricity on the free market (eg on HUPX or under corporate PPAs); however, subject to the outcome of regular open tenders, a certain surplus (premium) may be awarded to RES Generators as a state subsidy to ensure return on investment. However, the METÁR Regime requires participating RES Generators to pay money back when wholesale electricity prices are higher than the strike price established as a result of the tender. The detailed rules of the METÁR Regime are provided by Government Decree 299/2017. (X.17.).

Notwithstanding the above, the FiT Regime continues to apply for FiT Generators, ie those RES Power Plants that submitted their application for subsidy until 31 December 2016 and have been awarded an entitlement to participate in the FiT Regime.

Already existing biogas and biomass power plants are entitled to receive brown premiums under the METÁR Regime. Brown premium is a CfD type subsidy (working in the manner as described above) dedicated specifically for already existing biogas and biomass power plants that are no longer entitled to other types of operation subsidy (eg whose FiT entitlement expired). The brown premiums are determined by the HEA in individual licenses for a period of five years and are subject to annual price reviews.

The goals of the new support scheme are cost-effectiveness, the development of new generation capacities and ensuring competitiveness. Subsidies provided in the framework of the mandatory off-take regime, green premium and brown premium must promote the fair return of investments, meaning that no subsidy is due once the net present value an investment becomes positive.

F.2 Renewable pre-qualifications

The METÁR Regime or Premium System is, as a general rule, technologically neutral, ie it is open to any non-fossil and non-nuclear energy sources for generating solar, wind, geothermal, wave, tidal, hydropower and biomass energy, including energy sources produced directly or indirectly from biogases (landfill gas, sewage treatment plant gas and combustible gases produced from other organic substances). However, the installation of wind turbines is currently not possible due to administrative measures. A new tender in the Premium System is announced twice a year, each time with slightly modified terms.

In the last tender (March 2022) the minimum capacity of eligible power plants was 5MW, while the maximum was 50MW. The bid on the supported price was capped at HUF25,000/MWh (about €65/MWh). Winning projects were also required to install storage capacities equaling at least 10% of the installed capacity.

F.3 Biofuel

The Biofuel Directive was primarily implemented in 2010 by Act CXVII on the promotion of the use of renewable energy in transport and accordingly the decrease of greenhouse gas (GHG) emissions. Together with two pieces of secondary legislation, the provisions of the Biofuel Directive are considered to have been fully implemented in Hungary.

From 2020, the mandatory lowest ratio of biocomponents in all fuels has been 8.2% (and 6.1% in 95 octane petrol).

G. Climate change and sustainability

G.1 Climate change initiatives

The NECP provides a vision for the future of the Hungarian climate and energy sector in 2030. The main objectives are to make the energy sector 'clean, smart and affordable'. The NECP also focuses on the consumers, strengthening the security of supply, making the energy sector climate-friendly, and promoting innovation and economic development. Certain key action elements (among others) are:

- investments promoting the use of RES (including biogas, biomass power plants, geothermal energy);
- investments in the promotion of geothermal pumps for the heating and cooling of buildings;
- investments in energy storage facilities; and
- investments in the 'greening' of transportation including the establishment of electric charging stations.

G.2 Emission trading

RES Generators, further to the subsidies under the FiT and METÁR Regimes, also benefit from the system of tradable Guarantees as well. The purpose of the Guarantees is to verify to electricity buyers that the given volume of electricity originates from RES. Guarantees issued in other EEA member states also maintaining a system of tradable Guarantees are mutually accepted.

Until 31 December 2021, FiT Generators could request the HEA to issue one Guarantee for each MWh of electricity generated from RES. The awarded Guarantees were then allocated to an electronic account of the operator, and were tradable instruments, subject to market demand. Despite this, tradable Guarantees have not developed into a significant market in Hungary.

After the amendment of the Electricity Act and the Guarantees of Origin Decree entered into force on 1 January 2022, Guarantees of FiT Generators are no longer given to the generators, but must be sold by MAVIR at auction, more precisely on the HUPX GO which has been operated by HUPX since June 2022. In the first phase of the operation of the HUPX GO, MAVIR, as the nominated buyer of Hungarian FiT production, will be the only seller of the related Guarantees in quarterly auctions, while the buyer side is open to energy traders, end-users and other market participants. The incomes from the sale of such Guarantees will contribute to the fund financing the FiT Regime.

G.3 Carbon pricing

Carbon pricing in Hungary consists of primarily fuel excise taxes and to a smaller extent of carbon unit prices from the EU Emissions Trading Scheme (EU ETS).

G.4 Capacity markets

Under the respective Hungarian grid regulations, as the market operator, MAVIR is balancing the physical demand and supply of the electricity system through market measures, ie through balancing the energy market. Non-market measures, eg the forced amendment of generation schedules or the forced curtailment of electricity generation occurs only in the exceptional cases when the applied market measures are insufficient (eg major technical outages, extreme market anomalies). However, where such non-market measures are applied, the market operator must provide proper compensation to the affected power plants provided that the respective power plant's underlying grid connection agreement stipulates unrestricted feed-in availability.

H. Energy transition

H.1 Overview

The NECP foresees additional measures to tackle the challenges arising from the energy transition, including the support of energy efficiency measures, renewable fuels and smart city initiatives.

H.2 Renewable fuels

Hydrogen

To accelerate the green transition and reduce Hungary's dependence on energy imports, hydrogen is intended to become a substantial part of the Hungarian energy mix.

Accordingly, the Government adopted its National Hydrogen Strategy in July 2021. The main objectives are the production of large volumes of low-carbon and decentralised carbon-free hydrogen, the decarbonisation of industrial consumption (using hydrogen), the development of hydrogen-based green transport and the development of green balancing energy infrastructure.

Ammonia

There is no current or planned use of ammonia as a renewable fuel in Hungary.

H.3 Carbon capture and storage

The CCS Directive was introduced by a substantial amendment to the Mining Act. Under the Mining Act, the prospection, utilisation and closing down of geological structures suitable for carbon capture and storage is subject to a licence granted by the competent Mining Authority.

Prospecting activities may only be pursued on the basis of a prospection technical plan approved by the relevant territorial branch of the Mining Authority. If the prospection is successful, the relevant mining entrepreneur can then request that a mining plot is formed.

H.4 Oil and gas platform electrification

There is currently no oil and gas platform electrification in Hungary.

H.5 Industrial hubs

There are currently no industrial hubs in Hungary.

H.6 Smart cities

Certain major Hungarian cities, including Budapest and Debrecen, have already adopted smart city strategies.

The Smart City Budapest framework is a long-term umbrella strategy of the capital city which aims to significantly reduce the quantity of resources used, enhance the penetration of green mobility, create new and affordable education channels, improve quality of life, etc. The energy related chapters of the strategy are focused on the refurbishment of existing buildings to reduce energy use, setting up smart grids in relation to public transport and public utilities, and supporting green mobility and shared economy solutions.

I. Environmental, social and governance (ESG)

ESG-related expectations and requirements are slowly but steadily gaining ground in the Hungarian business landscape. The major ESG related changes are:

- introducing mandatory energy efficiency reporting obligation for major enterprises;
- publishing an ESG Reporting Guide for issuers of the Budapest Stock Exchange;
- encouraging green investments through subsidised loan schemes; and
- growing interest in long-term green PPAs.

Energy law in Iceland

Recent developments in the Icelandic energy market

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Sustainable energy future

In October 2020, the Minister of Tourism, Industry, and Innovation ("MTII") published an Energy Policy for 2050[1] (the "Energy Policy"), outlining a clear vision of a sustainable energy future. The Energy Policy is Iceland's first long-term energy policy and aims to protect the interests of both the current generation and future generations; efforts will be made to meet contemporary needs without curtailing the opportunities for future generations to meet their future needs. The future vision recognises the need for sustainable development and the importance of energy in the lives of the Icelandic population. The Energy Policy reflects the interaction between energy utilisation, environmental protection, and economic development, and the importance of these factors working together in harmony.

The Energy Policy presents a scenario for 2050 and describes the progress aimed for over a period of 30 years. By 2050, fossil fuels will have been entirely replaced by renewable energy sources ("RES"). Iceland will have achieved carbon neutrality by 2040, as planned in Iceland's Climate Action Plan.[2] Energy security has been achieved through a supply of varied renewable energy options and sound infrastructure. In the country, there is a general agreement on the need to balance the use of energy sources with conservation of nature and the development of energy infrastructure. Consumers have equitable and secure access to energy at competitive prices in an efficient energy market. The energy network is smart and flexible, with a focus on minimising waste. The economy benefits from the value creation, knowledge, and innovation arising from the energy sector.

Government administration will have an important role to play in supervising enterprises operating under concession contracts and in monitoring significant benchmarks, eg, regarding energy security, statistics, and the preparation of forecasts that are necessary for the government in deciding on policies. Also, administrative organisations and municipalities will watch over a regulatory framework designed to protect communities and businesses while at the same time considering environmental matters and compliance with the law. There will also be agencies and complaint boards that the public can consult if they believe their rights have been violated.

Hydrogen

In Iceland, hydrogen is receiving increased attention as a RES. 'Green by Iceland' *(Grænvangur)*[3] is a project and sub-governmental body founded by the Icelandic Government and parties of the energy industry, among which is Landsvirkjun, the national power company. The aim of the project is to support Iceland's Climate Action Plan[4] for being carbon neutral by the year 2040. Parties to the project, especially on the industry side, have urged governmental bodies to prepare a separate hydrogen policy for Iceland that is in line with what other countries are doing, especially Germany, along with the EU. Political discussion regarding such a policy is currently underway in Iceland.

However, no significant green hydrogen projects have yet been announced. Some parties of the energy industry have conducted extensive research in the field and are even prepared for some experimental projects, but they seem to await policies from the government before being able to act unitedly. *Landsvirkjun* is working on a hydrogen production project in one of its hydropower-plants[5].

Although, a development company called *Vetnis* has been focusing on the production and distribution of green hydrogen to power local heavy-duty transport. The company specialises in the simultaneous development, production and distribution of green hydrogen. Amongst future projects is the first hydrogen truck fleet in Iceland. Further information can be accessed on their website.[6]

Energy transition

The energy transition is now in progress in land, sea, and air transport. With the transition, fossil fuels are set to be replaced by RES. The long-term objective of the energy transition is for Iceland to no longer be reliant on fossil fuel and to meet all the energy needs of the country using RES.

The energy transition is making progress in transport on land. Iceland aims to increase the share of renewable energy in on-land transport from 10% in 2020 to 40% by 2030. The objective of the energy transition on land is for motor vehicles to be powered by RES. The appropriate infrastructure is necessary, as there is an emphasis on the Icelandic population having easy access to RES. TSOs and DSOs are also aware of the development and will need to ensure the transmission and distribution of the relevant energy sources. Transport by sea and air is at a preliminary stage.

Economic incentives and concessions will encourage consumers and businesses to choose renewable energy options. The development of infrastructure, such as charging stations outside urban areas, will support the transition. Increasing the energy efficiency of fuel, whether fossil fuels or renewable fuels, will contribute to energy savings.

In February 2022, Landsvirkjun and Icelandair, Iceland's largest airline, announced that they are working together to develop solutions for the energy transition in aviation in Iceland[7]. Together, the companies will assess the current situation in preparation for projects intended to advance the progress of the transition in aviation. A two-year term agreement has been signed to assess the possibility of implementing a development project, with the objective to create a platform for stakeholders and promote cooperation for the energy transition in aviation and inform both the public and stakeholders about the importance of the energy transition in aviation.

Updated Climate Action Plan

The Climate Action Plan is Iceland's main instrument that establishes Iceland's aims to reach its commitment under the Paris Agreement, specifically its emissions reduction goals for 2030. It is also the main instrument that outlines how Iceland aims to reach its stated goal of carbon neutrality by 2040. In 2020, the Minister for the Environment and Natural Resources (the "MENR") published an updated Climate Action Plan, which includes a total of 48 actions that are expected to decrease emissions in 2030 by more than one million tonnes of carbon dioxide ("CO_2") compared to 2005 in sectors that fall under the EU effort sharing regulation (the "ESR").

If all goes to plan, this means that Iceland should meet its climate commitments for a 29% reduction in ESR emissions from 2005 levels, as analysis indicates that Iceland should be able to reduce emission in the specified sectors by 35% through implementing the actions set out in the Climate Action Plan. In addition to this, actions currently in preparation are estimated to result in an additional cut in emissions of 5-11%, for a total decrease of 40-46% by 2030.

The Icelandic Government has signalled a willingness to achieve a reduction in emissions in ESR-sectors by 40%. This is more than is currently demanded by Iceland's international commitments. A minimum of ISK46 billion is expected to be spent on key climate action in the period 2020-2024. Actions taken in the areas of carbon sequestration and wetlands restoration are expected to lead to significant benefits, with an estimated increase of more than 500% compared to 2005 levels. These measures play an important role in achieving Iceland's goal of carbon neutrality by 2040.

CarbFix – capturing and storing CO_2

CarbFix[8] is an academic-industrial partnership which has developed a novel approach to capture and storing CO_2 by its capture from water and its injection into subsurface basalts. Research has shown that 95% of injected CO_2 solidifies within two years, using 25 tonnes of water per tonne of CO_2. CarbFix captures CO_2 either by its dissolution in water from power plant exhausts, or directly from the atmosphere by air capture followed by its dissolution in water. CarbFix operates a CO_2 capture and storage facility at *Hellisheiði* in Iceland, and ongoing research is implementing CarbFix approach. The CarbFix approach is currently being adopted at four new sites in Europe through the EU funded Geothermal Emission Control ("GECO") project.

Since 2014, CarbFix has injected just under 70,000 metric tonnes of CO_2 into subsurface basalts. Theoretically, CarbFix estimates that Europe could store at least 4,000 billion tonnes of CO_2 in rocks and has mapped out places[9] where the technology works.

Geothermal energy project between Iceland, Lichtenstein and Norway and Poland, Hungary and Slovakia

In October 2020, a project entitled 'Improving the energy efficiency of geothermal energy utilisation by adjusting the user characteristics' (the "Project") was launched. The Project is funded by Iceland, Lichtenstein, and Norway (the "Donor Countries"), through the EEA, and Norway Grants Fund for Regional Cooperation. The Project aims to increase the economics of geothermal district heating systems in Poland, Hungary, and Slovakia (the "Beneficiary Countries"), to support their sustainability and to decrease air pollution and CO_2 emissions. Meeting these goals should contribute to getting geothermal district heating ("DH") systems more popular in cities and to contribute towards mitigating climate change.

The Project aims to increase economic as well as environmental and climate benefits for the participating countries, as well as other countries of the world, by exchange of good practices in the management of geothermal DH between the Donor Countries and the Beneficiary Countries.

Other significant industry developments

The National Regulatory Authority published 12 Power Plant possibilities that had not previously been considered: ie one geothermal power plant, five hydropower plants, and six wind turbines. Included in the possibilities was the expansion of Landsvirkjun's (the biggest electricity producer in Iceland) three power plants. Landsvirkjun operates 19 power plants with the total production capacity of 2.155MW.

In recent years, data centres have begun operations in Iceland and developments in this area has resulted in data centres being potential future energy intensive customers. Iceland's RES, cool climate, regulatory certainty, and stable environment have been referenced when establishing the data centre industry in Iceland.[10] Since 2016, energy consumption by data centres in Iceland has quadrupled, and from 2018 to 2019, the amount of electricity sold by Landsvirkjun to data centres increased by 50%. Presently, four data centres purchase electricity from Landsvirkjun, Reykjavík DC, Etix Everywhere Iceland (Borealis Data Center), Advania Data Centres and Verne Global. There is currently an increased demand for electricity, particularly due to Iceland's goal to become carbon neutral. However, no decision has been made for new power plants in Iceland.

In February 2021, the Iceland Drilling Company (*Jarðboranir hf.*) handed over its extensive drilling report collection to the National Energy Authority for the purpose of filing and preservation.[11] The aim is to record and scan the contents of the drill report collection and make it available over time in a web solution, as well as other historical data that the National Energy Authority has been publishing recently, such as statistical information regarding the production, use and price of energy and various data on the energy resources already in use in Iceland.[12] The additional information being published by the National Energy Authority is a welcome addition to the information already available at the authority; the most well-known database is without a doubt the 'Borehole Register', which contains information on over 14,000 boreholes in

Iceland drilled since 1904.

In December 2022, the Ministry of Finance and Economic Affairs, on behalf of the Icelandic public treasury, entered into an agreement with Landsvirkjun, RARIK and Westfjord Power Company, in relation to the Icelandic State's acquisition of 93.22% of Landsnet's share capital. As a result of that agreement, Landsnet, the Icelandic TSO, is owned by the Icelandic State (93.22%) and Orkuveita Reykjavíkur (6.78%).

Endnotes

1. See www.stjornarradid.is/lisalib/getfile.aspx?itemid=e36477fd-3bc1-11eb-8129-005056bc8c60.
2. See www.government.is/library/01-Ministries/Ministry-for-The-Environment/201004%20Umhverfisraduneytid%20Adgerdaaaetlun%20EN%20V2.pdf.
3. See www.graenvangur.is (available only in Icelandic).
4. See www.government.is/library/01-Ministries/Ministry-for-The-Environment/201004 Umhverfisraduneytid Adgerdaaaetlun EN V2.pdf.
5. See www.landsvirkjun.is/frettir/graent-vetni-er-umhverfisvaenn-orkugjafi (availalbe only in icelandic).
6. See www.vetnis.com.
7. See www.landsvirkjun.com/news/collaboration-on-the-energy-transition-in-aviation.
8. See www.carbfix.com.
9. See www.carbfix.com/atlas.
10. See www.landsvirkjun.com/data-centers.
11. See www.orkustofnun.is/orkustofnun/frettir/jardboranir-hf.-afhenda-orkustofnun-borskyrslusafn (available only in Icelandic) and https://orkustofnun.is/borholuleit.
12. See www.nea.is/the-national-energy-authority/energy-data/.

Overview of the legal and regulatory framework in Iceland

A. Electricity

A.1 Industry structure

Nature of the market

The market for the sale of electricity in Iceland has been open to competition since 2006. Under the Electricity Act no. 65/2003 ("Electricity Act"), an authorisation from the National Energy Authority ("NRA") (icel. *Orkustofnun*) is required to operate a business for the sale of electricity.[1] However, such authorisation is distinct from the generation licence and the distribution licence and therefore does not constitute an exclusive right for the entity to which it is granted.

Iceland is a member of the internal market of the European Union ("EU") by virtue of the European Economic Area Agreement ("EEA Agreement"). Iceland's legislation with respect to the energy market is therefore highly influenced by EU legislation. However, directives and regulations of the EU are not binding for Iceland until they have been adopted into the EEA Agreement by a decision of the EEA Joint Committee, and until all of the European Free Trade Association ("EFTA") member states have fulfilled their respective constitution's requirements for approval of the decision.

Key market players

The Electricity Act defines the structure of the electricity market, and the rights and obligations of the main market players. The Electricity Act divides the electricity market into four main sectors, ie, generation, transmission, distribution, and supply.

The five major generators of electricity are Landsvirkjun, Orkuveita Reykjavíkur, HS Orka hf, Fallorka and RARIK ohf. The Icelandic transmission system operator ("TSO") is currently Landsnet hf, a limited company created by Act no. 75/2004. Landsnet is currently owned by the Icelandic State (93.22%) and Orkuveita Reykjavíkur (6.78%). There are currently six distribution system operators ("DSOs") in Iceland; each of these has been allocated to a specific area. There are currently nine market players licenced for electricity trading, one of which does not provide electricity to the public. The largest traders of electricity are Landsvirkjun, HS Orka, and Orkuveita Reykjavíkur.

Regulatory authorities

Under the Electricity Act, two authorities are in charge of regulating the energy market, ie the NRA and the Icelandic Competition Authority ("NCA"). The NRA is primarily responsible for ensuring that energy companies comply with their legal obligations under the Electricity Act and derived regulations. The NRA also issues the revenue caps necessary to calculate TSO and DSO tariffs, and supervises the control of quality and security of supply of electricity. Recently, the supervisory role of the NRA was strengthened, and the NRA can now impose fines in certain cases where an entity or an individual acts in violation of the Electricity Act, such as operating a power plant without a licence.

The NRA is responsible for reviewing the network development plan submitted annually by the TSO. The NRA will consult with the NCA on the regulation of the operation and tariffs of TSOs and DSOs. In relation to the unbundling regime, the NCA can order the formal separation of activities in order to prevent energy companies from subsidising their activities open to competition with another licensed activity, as per Article 27(2) of the Electricity Act.

On 2 September 2019, parliament passed a resolution ratifying the Decision of the Joint EEA-committee no. 39/2017 of 5 May 2017, which inter alia incorporates the Third[2] Electricity Directive in the EEA Agreement (the "Joint Committee Decision"). According to the Joint Committee Decision, the national regulatory authorities of EFTA member states will participate fully in the work of the Agency for the Cooperation of Energy Regulators ("ACER"). The ACER Regulation has been adapted in order for the ACER regulatory framework to fit within the EFTA/EEA institutional framework. For instance, the EFTA Surveillance Authority ("ESA") will adopt the binding decisions addressed to one or more EFTA member states that would normally be taken by ACER.

Legal framework

The main statute regulating the electricity market is the Electricity Act. Other statutes in the field of construction, planning, environmental impact, and natural resources[3] may also be relevant to the construction of electricity installations.

Some regulations have been issued under the Electricity Act, such as Regulation no. 1050/2004 on electricity trading and metering, Regulation no. 513/2003 on the management of the electricity network, Regulation no. 1048/2004 on the quality of electricity and the security of supply, Regulation no. 1040/2005 on the implementation of the Electricity Act, Regulation no. 350/2016 on the surveillance plan for the equal treatment of the TSOs clients, and Regulation no. 870/2016 on the network development plan.

In 2011, the Ministry of Industry and Energy published an energy policy for Iceland, with the main objectives of ensuring that energy production and consumption in Iceland would be sustainable and be managed in such a way that serves the public interest. In 2020, the Ministry of Industries and Innovation published an updated policy, extending to the year 2050. The objective of the policy is protecting the interests of both the current generation and future generations. The policy is guided by the objective of sustainable development, and reflects a balance between economic, social, and environmental factors. The policy is structured on the basis of a future vision, firm guidelines, and principal objectives. It also focuses attention on the pillars on which the policy rests, considering the entire energy value chain, from resource to consumer.

Another essential instrument of the energy sector regulatory regime in Iceland is the master plan for hydro and geothermal energy resources ("Master Plan"). The Master Plan has been in development since 1997 and is split into four phases. The results deriving from the first two phases was evaluation of about 100 energy options, including geothermal and hydro energy options. The evaluation committee issued an evaluation report in June 2011, and in May 2011 parliament passed a bill that gave the Master Plan legal force[4]. The main purpose of the Act is to ensure that the use of territories that have energy resources will be based on an overall assessment of interests and long-term objectives in which the preservation of nature and cultural heritage, economical aspects, and other public interests are secured. The Act requires parliament to issue a recommendation every four years, based on the Master Plan, as to which suitable energy projects should be permitted.

The third phase evaluation began in 2013 and was completed in 2016, whereas eight power plant options were evaluated and added to a list of energy utilisation options. The fourth phase evaluation began in 2017 and is ongoing. In March 2021, as part of the fourth phase, an experts committee submitted its recommendations to the Minister for the Environment and Natural Resources, which included recommendations for categorisation of power options. On 15 June 2022, the Icelandic parliament approved a parliamentary resolution on the updated classification of power generation options and protection of future options. The parliamentary resolution on the categorisation of power options became legally binding. A total of seven power options were put on hold, four of them were previously in the protection category of the framework plan and three in the exploitation category. One power option was moved to the utilisation category but was previously in the standby category. For the first time, wind energy zones were included in the utilisation category of the framework with two offshore areas defined.

Another important statute is the Act on Investments of Foreign Parties in Businesses no. 34/1991. This prohibits non-EEA residents from holding energy exploitation rights for hydro and geothermal energy unless specifically authorised by bilateral investment treaties. A similar restriction applies to generators or distributors of energy. This statute has been controversial in Iceland and there is considerable political pressure for a change.

The Electricity Act currently provides for a hybrid model halfway between a fully unbundled regime and the ITO model. The TSO is a separate entity and as provided by the Electricity Act, the TSO is majority owned by the State, municipalities and/or companies wholly owned by these parties[5]. The implementation of the Third Electricity Directive did not change the structure of the TSO as the Joint Committee Decision provides that Article 9 of the Third Electricity Directive does not apply to Iceland.

The Electricity Act provides for a similar unbundling regime in relation to DSOs. Under the Electricity Act, DSOs in distribution areas with more than 10,000 inhabitants must not have any other activities, as per Article 14 of the Act. Furthermore, the board of a DSO must remain independent from other energy companies involved in the generation, distribution, or supply of electricity. By definition, the unbundling regime of Article 26 of the Third Electricity Directive applies to Iceland. However, Iceland may apply for derogations from Articles 26, 32 and 33 of the Third Electricity Directive if it can demonstrate that there would be substantial problems for the operation of its systems if the unbundling regime were implemented.

Implementation of EU electricity directives

Three of the main EU directives concerning the energy market have been implemented into Icelandic legislation. These are the First and Second Electricity Directives, and the Renewable Energy Directive. The Third Electricity Directive has been incorporated in the EEA Agreement by the Joint Committee Decision. Iceland was granted several derogations from the Third Electricity Directive, as being a small isolated system and the transmission and distribution systems of electricity in Iceland are not entirely comparable to those of other countries. Also, Iceland was granted a derogation from the Third Gas Directive and the Gas Regulation, as there are no sources of natural gas in Iceland, and consequently it has no infrastructure in place for its distribution.

A.2 Third party access regime

The TSO and DSO must connect to the relevant grid any parties requesting access, provided that such party complies with the conditions set out by regulation and pays the relevant transmission or distribution fee.[6] However, access can be denied on the grounds of insufficient capacity or security and quality of the system. Such a restriction must be in writing and reasoned.

A.3 Market design

A generation licence is necessary for the construction and operation of power plants with a capacity of more than 1MW (see section A.5). The activity of electricity trading is subject to authorisation by the NRA. The transmission system is operated by one company, which is granted a special licence for that purpose. DSOs are granted a distribution licence by the NRA and must at all times have a majority ownership by the State or municipalities (see section A.5).

Under the Act on Investments of Foreign Parties in Businesses no. 34/1991, foreign ownership of Icelandic energy companies is somewhat limited. In principle, only Icelandic citizens or other Icelandic entities may own rights to generate power from hydro or geothermal resources for purposes other than personal use unless specifically authorised in bilateral investment treaties. The same applies to businesses specialising in power generation and distribution. Since 2006, the ownership of these businesses is also open to individuals or legal entities with their registered office or domiciled in other member states of the EEA, EFTA or in the Faroe Islands.

A.4 Tariff regulation

The use of the transmission system is subject to the payment of an annual transmission tariff by the relevant user. The transmission tariff is calculated by the TSO based on the revenue cap issued by the NRA. The NRA issues two kinds of revenue caps; one for transmission to DSOs, and one for transmission to power intensive users. The TSO also charges energy producers for feeding energy into the transmission system. Power plants with a capacity of more than 10MW must be connected to the national transmission system[7]. Power plants with a lower capacity may be connected directly to a regional distribution system. In such case, the input charge must be paid to the relevant DSO.

As of 1 April 2022, transmission tariffs in Iceland are:

Input:	
Capacity charge per MW per year	ISK 711,672
Output:	
Distribution system operators:	
Delivery charge per year	ISK 6,584,826
Capacity charge per MW per year	ISK6,760,830
Energy charge per MWh	ISK 489.56
Power intensive users:	
Delivery charge per year	US$47,097
Capacity charge per MW per year	US$ 27,435
Energy charge per MWh	US$1.388

A.5 Market entry

Generation

Electricity generation is subject to the issuance of a licence by the NRA. The construction of electricity plants also requires such a licence to be obtained. No licence is required for the construction and operation of power plants with a nominal capacity of lower than 1MW, unless the power generated by that plant is supplied to the distribution system or transmission system. If the nominal capacity of the power plant is lower than 100kW, no generation licence is needed. A generation licence expires ten years following the date of issue if its beneficiary has not yet commenced construction. If construction has begun but operation has not commenced, the relevant Generation Licence expires 15 years following the date of issue.[8] The beneficiary of a Generation Licence can apply for an extension.

The main conditions to be fulfilled for the issuance of a Generation Licence are:

- the applicant must be an independent legal and tax entity;
- a Generation Licence can only be granted for the construction and operation of power plants using renewable energy sources ("RES"); and
- to the extent relevant, a final decision from the administration on the environmental impact of the project must be provided.

All construction operations based on the Generation Licence must conform to the urban planning requirements in force. Before commencing any construction work or operations, the beneficiary of the Generation Licence must prove that the necessary finance can be raised.

Transmission

Under the Electricity Act, the transmission system can only be operated by one independent limited company. The TSO maintains a transmission system that integrates the objectives of security, efficiency, and the reliability of supply and quality of electricity. The TSO is responsible for connecting the relevant parties to the transmission system, for balancing the electricity system by procuring energy to cover the loss in the system and, thereby, for ensuring the reliability in the operation of the system and ensuring the offer of reserve capacity. The TSO may not carry out any other activities, except that it may operate the electricity market, provided that certain conditions relating to its accounts are fulfilled. The TSO has worked on the creation of an energy market, ie ISBAS, which is an electronic market for electricity trading. To date, the market has not yet opened.

Distribution

A distribution licence granted by the NRA is necessary to build and operate a distribution system. The majority shareholding of any DSO will always be owned by the Icelandic state, municipalities or entities wholly owned by them.[9]

The role of DSOs is to oversee and manage the distribution of electricity in the area allocated to them. DSOs also have the duty to build and maintain such distribution systems that integrate the objectives of security, efficiency, reliability of supply and quality of electricity.

A.6 Public service obligations, smart metering and electric mobility

Public service obligations (PSOs)

The Electricity Act imposes PSOs on the TSOs and DSOs, such as the obligation to maintain, improve, and develop network systems economically, considering security, efficiency, the security of supply, the quality of the electricity as well as the Icelandic government policy on the transmission system. The PSOs provided for in the Electricity Act are to, among other things:

- connect all parties that apply for such connection to the network, subject to conditions being fulfilled. The operators can deny access for certain limited reasons. The denial must always be in writing, stating the grounds for such denial;
- ensure reliability in the operation of the system;
- provide electricity as compensation for electricity that is lost in the transmission or distribution system;
- supply public authorities, customers, and the public with information necessary to assess whether the operator is performing its obligations; and
- operate in a non-discriminatory manner and maintain confidentiality regarding information relating to the business interests of final customers and all other information that should fairly and reasonably remain confidential.

Smart metering

The Icelandic TSO is now focusing on digital development and has made an ambitious decision that all new and refurbished substations be made fully digital. The utility has already implemented local smart grid schemes. Its transition to a digital substation will further raise the requirement for inter-substation communication. Therefore, making the most out of the implementations will extend the possibilities for smart grid development, improving flexibility for the transmission system as well as customers.

In 2018 the TSO implemented a Smart Grid control system, developed by the European research project 'MIGRATE', which is to provide stability and security in transmission of electricity in Iceland. However, Iceland does not have an explicit policy on smart grids or smart metering. Furthermore, few smart grid development projects are underway, although the TSO continues engaging in digital development as it has proven to be effective in terms of transmission system operation and cost compared to other investments. For example, the TSO operates a micro smart grid in North-western Iceland.

The TSO has ongoing work to develop a new ancillary service and settlement format for fast frequency response providers to increase the available volume of response and further improve the overall stability and reliability of the transmission system.

Electric vehicles

Iceland's Climate Action Plan ("Action Plan"), as launched in September 2018 and extending to the year 2030, includes electric vehicles ("EVs"). Under the new Action Plan, Iceland will ban new registrations of fossil fuels cars after 2030. Iceland already has generous temporary tax incentives for the purchase of electric cars and other clean vehicles and recently the Icelandic government introduced a VAT discount for the resale of eco-friendly vehicles. The tax incentives have had a positive effect of the Icelandic market and in 2021, newly registered electric cars accounted for 58% of all newly registered cars in Iceland and for the first months for 2022 that percentage was 70%. Furthermore, under the new energy policy extending to 2050, the Icelandic government will increase governmental support of the build-up of charging stations for EVs and also extend the support to infrastructure of other types of clean energy and fuels, such as hydrogen and methane. Building and spatial planning rules and regulations will be reviewed to ensure that new buildings will be designed allowing for infrastructure to charge electric cars. A system of rebates for decommissioning high-polluting cars is also currently being reviewed as it may speed up the phase-out of older high-polluting cars. Government offices and state enterprises will also be in the forefront of cleaning up transport in Iceland over the next few years by using electric cars or other non-emitting vehicles for their own use.

A.7 Cross-border interconnectors

Due to its geographical position, Iceland does not have any interconnections with other countries. However, Iceland is working on a submarine electricity cable project. Such submarine cables would enable the exportation of electricity to other countries and allow for the diversification of the Icelandic energy market. Several projects are being considered including cables to Norway, Scotland, or Germany. The IceLink project between Iceland and the UK is set to lift the isolation of the Icelandic electricity market and assist Europe to achieve interconnection capacity targets amounting to 10% of installed capacity. The project also opens new markets for both Iceland and UK suppliers.

B. Oil and gas

B.1 Industry structure – oil

Nature of the market

All oil in Iceland is imported by Icelandic oil companies from suppliers abroad and it is transported to storage facilities located around Iceland, owned by the Icelandic oil companies. The sale of fuel in Iceland is managed by a few distributers, both through fuel stations and by direct sale to larger buyers.

Key market players

The two largest oil companies in Iceland, N1 (owned by the listed company Festi) and Skeljungur, are listed on NASDAQ OMX Iceland. Three other companies can be identified as key market players: Olís and Atlantsolía, with operations around Iceland, and Costco Iceland with operations in the capital area (around Reykjavík).

Regulatory authorities

Not applicable – the oil and fuel market in Iceland is not regulated separately from other markets.

Legal framework

Not applicable – the oil industry is not subject to separate legal framework.

B.2 Industry structure – gas

Nature of the market

There are no natural gas activities in Iceland.

Implementation of EU gas directives

The Second Gas Directive is incorporated into the EEA Agreement, however, it has not been implemented in Iceland. The reason for the non-implementation of the Second Gas Directive is that there are no natural gas systems operating in Iceland and no plans have been made to initiate such systems.

B.3 Third party access regime to gas transportation networks

Not applicable (see section B.2).

B.4 LNG terminals and gas storage facilities

Not applicable (see section B.2).

B.5 Tariff regulation

Not applicable (see section B.2).

B.6 Market entry

Not applicable (see section B.2).

B.7 Public service obligations and smart metering

Public service obligations (PSOs)

Not applicable (see section B.2).

Smart metering

Not applicable (see section B.2).

B.8 Cross-border interconnectors

Not applicable (see section B.2).

C. Energy trading

C.1 Electricity trading

In Iceland, electricity trading takes place through bilateral contracts. Although Icelandic law provides for the possibility of a power exchange, no such market has been created in Iceland to date.

As the electricity trading sector has been open to competition since 2006, an electricity supplier need not be an electricity generator. However, in most instances, Icelandic electricity suppliers are also energy producers, and their majority shareholders are the Icelandic state or municipalities. There are some exceptions, such as HS Orka, which is partially owned by a privately owned foreign entity.

Electricity supply to household consumers is made based on standard electricity supply contracts. Such contracts must be in writing. The parties to such contracts can agree to enter into an ad hoc agreement, which must also be in writing. Household consumers and electricity suppliers are entitled to terminate the electricity supply contracts with one month's notice. If a consumer defaults in payments, the electricity supplier is entitled to request the relevant DSO to stop the delivery of electricity. The DSO acts, upon notification of the electricity supplier, on its own initiative if a cancellation of delivery is used as a remedy for the non-payment of distribution fees. In all circumstances, a warning notice must be sent to the consumer with 14 days' written notice, informing the consumer of the intended break in supply. The electricity supplier is also entitled to terminate the electricity supply contract if the household consumer does not make the contractual payment. The termination is subject to 14 days' written notice. Claims for payment of electricity price and distribution and transmission fees are immediately enforceable; they do not need to be recognised in a judgment to become enforceable. Electricity suppliers are entitled to collect the payments for the sale and distribution of electricity. The invoice must specify the amounts charged for the sale, transmission, and distribution of power, respectively.

Large-scale users and electricity suppliers generally enter into ad hoc agreements with electricity generators.

C.2 Gas trading

Not applicable (see section B.2).

D. Nuclear

Iceland does not have any nuclear power plants.

E. Upstream

Oil and gas exploration has, to date, not reached beyond the prospection stage in Iceland. This is changing as seismic surveys and other geophysical measurements indicate that producible quantities of oil and gas could be found in the Dragon Area. The Dragon Area is located in an area of the North-Atlantic Ocean north-east of Iceland, a part of which is held by Iceland and a part of which is held by Iceland and Norway jointly. NRA issued two hydrocarbon exploration licences on 4 January 2013. This marks the beginning of upstream hydrocarbon activity in Iceland.

The Hydrocarbons Licensing Directive has been implemented in Iceland by Act no. 13/2001 on prospecting, exploration, and production of hydrocarbons ("Hydrocarbon Act"). Other relevant statutes, regulations, and international agreements in the field of upstream hydrocarbon activity are:

- Act no. 109/2011 on the Taxation of Hydrocarbon Extraction ("Hydrocarbon Tax Act");
- Regulation no. 884/2011 on Prospecting, Exploration and Production of Hydrocarbons ("Hydrocarbon Regulation");
- Regulation no. 39/2009 on the Hydrocarbon Research Fund; and
- Agreement of 22 October 1981 between Iceland and Norway on the continental shelf in the area between Iceland and Jan Mayen.

The governmental agency in charge of upstream hydrocarbon activity is the NRA.

E.1 Ownership of the hydrocarbons

The hydrocarbons outside the 115 metres zone from the shore (*Icel. netlög*) within Iceland's territorial waters and economic zone and on the Icelandic continental shelf are under the ownership of the Icelandic state. However, under the Hydrocarbon Act, the holder of a production licence may be granted ownership of the hydrocarbons that they produce. By leaving the question of the ownership of the hydrocarbons open, the Hydrocarbon Act allows for several regimes to be put in place, such as concessions, licences, or production sharing contracts.

E.2 Licences

Under the Hydrocarbon Act, there are three types of licences, all granted by the NRA, ie a licence to prospect, a licence to explore and a production licence.

A licence to prospect for hydrocarbons is generally granted for a period of three years at a time. The holder of a licence to prospect for hydrocarbons does not have the right to engage in exploration or production of hydrocarbons and does not enjoy any priority to obtain a licence to engage in such activities. The prospection licence is cancelled if the licensee does not pay the supervision fee when it is due.

Licences for the exploration and production of hydrocarbons give the licensee exclusive rights for exploration and production and may only be granted to applicants who are considered by the NRA to have the requisite expertise, experience, and financial capacity to undertake these activities. It is also a condition for the granting of a licence that a company is incorporated in Iceland for the purpose of the hydrocarbon activities in the country. This condition is fulfilled in the case of an Icelandic branch or agent of a company registered in an EEA or EFTA member state or in the Faroe Islands. There is no requirement as to the form of the company, but it must be registered with the Icelandic registry of incorporations, and the NRA may impose certain requirements regarding the organisation and the equity structure of the licensee. The object of the licensee must be linked with prospecting, exploration and/or the production of hydrocarbons. Exploration and production licences, or parts thereof, cannot be transferred, directly or indirectly, to a third party or another licensee of the same licence without the permission of the NRA. In addition, the transfer of shareholding or other titles of ownership in such a volume that may change the ruling majority in a company holding or co-holding a licence, or making contracts to the same effect, requires the consent of the NRA. The NRA may demand a fee for permitting transfer of licences. It should be noted that the Hydrocarbon Act has recently been amended to enable the application of joint ventures for exploration and production licences.

Upon the granting of an exploration and production licence, the NRA will decide on an operator for each licence. The conditions applicable to the licensee generally apply to the operator.

However, more stringent requirements may apply to operators. Operators may, for example, be requested to give additional information regarding their experience, such as a list of oil or gas fields worldwide that have been or are in operation, or a review of the measures made by the relevant operator on these fields or previous drilling experience.[10] The appointment of a new operator must be submitted to the NRA for approval. In special circumstances the NRA may change operators on its own initiative.

The operator is responsible for the calculation and payment of the fee on behalf of the licensee. Additionally, the NRA is permitted, when deciding on an operator, to provide that liability for damages should also extend to an operator who is not a licensee.

E.3 Licensing rounds

The process for the granting of exploration and production licences is described chiefly in Article 8 of the Hydrocarbon Act. Iceland usually carries out licensing rounds. The main features of the process are as follows:

- a public notice inviting applications is normally published in the National Gazette and the Official Journal of the European Community prior to the granting of the licence;
- the deadline for the application is indicated in the notice and may not be shorter than 90 days;
- the notice defines the area to which the licence applies and other conditions of the licence;
- discrimination between applicants in the granting of a licence is prohibited, and the equality of rights must be observed;
- decisions on granting a licence for exploration and production are based mainly on considerations of the financial and technical capacity of applicants, on whether the production from a given resource is viable by measures in relation to the demands of the national economy and ways in which the submitted exploration plan may reach a given goal; and
- if the NRA considers two or more applications equal according to the criteria given above, the NRA is permitted to rate applications by other criteria.

In limited cases, the NRA may also grant exploration and production licences without public notice.

A licence for exploration will be granted for a period of up to 12 years, and the term may be extended for up to two years at a time. The maximum duration of such exploration licence may not exceed 16 years.[11] The holder of an exploration licence has priority for the granting of a production licence for up to 30 years, provided that the conditions of the exploration licence have been fulfilled. The NRA may request the licensee to relinquish a certain part of the licence area before extending the production licence. A model licence for exploration and production of hydrocarbons is used by the NRA and is part of the documents submitted to potential bidders in licensing rounds.

If the licensee ceases production for more than three consecutive years, the licence is cancelled at the end of that three-year period. The licence may be revoked if the licensee is taken into liquidation or seeks a voluntary arrangement with its creditors. Exploration and production licences are cancelled if the supervision fee is not paid when it is due.

E.4 Security interest in offshore facilities

The NRA may limit its approval for the construction and instalment of offshore facilities and the operation of pipelines with equipment for the production and transportation of hydrocarbons. Approval must be given by the NRA for any form of security interests or any other direct or indirect ownership rights, including option rights or other such rights, of a third party to offshore facilities, partially or wholly, that are connected to the licensee's hydrocarbon activities.

E.5 State participation

Under the Hydrocarbon Act, the Icelandic state may participate in hydrocarbon production. If the state decides to exercise its right to participate, it must incorporate a special purpose limited liability company in charge of guarding the interests of the Icelandic state. The Hydrocarbon Act provides for further details such as the composition of the company's board and the objectives and tasks of the company. The company may not operate as a production company.

Under an agreement between Iceland and Norway from 1981, Norway has the right to a participation of up to 25% in exploration licences that relate to a specific part of the Dragon Area.

E.6 Taxation

The Hydrocarbon Tax Act provides for the main tax framework applicable to the production of hydrocarbons. The taxation of hydrocarbon production is threefold, consisting of a production levy, an area fee, and a special hydrocarbon tax. The area fee is calculated and charged in accordance with the provisions of the Hydrocarbon Act and corresponds to the fee charged for the granting of prospection, exploration or production licence for a given area. Licensees must also pay a special production levy based on the quantity of hydrocarbons, counted in barrels, that they produce each year. The production levy is 5% and is a part of operational expenses. It is paid monthly as a withholding tax. The special hydrocarbon tax is levied on the profit generated by the activity. Its rate is progressive and is calculated as the product of the profit rate and the ratio of 0.45. Payment of the special hydrocarbon tax is made in advance towards the final levying, based on retrospective assessment.

E.7 Decommissioning

Under the Hydrocarbon Act, the decommissioning of an offshore installation, including the cessation of maintenance, is subject to the consent of the NRA. Licensees must present themselves to the NRA for approval, and they must provide a plan for decommissioning offshore installation, which contains, among other things, information on how decommissioning will take place. The plan for decommissioning must fulfil the requirements of the Hydrocarbon Act, the relevant licence, and the Hydrocarbon Regulation. The plan must also contain information on the following items:

- the extraction of hydrocarbons in the area;
- the location and nature of the offshore facility;
- possibilities for continued production;
- recommendations of the licensee on a method for decommissioning, including an implementation schedule;
- alternative methods for decommissioning an offshore

facility; and

- other items of importance in connection with the selection of methods for decommissioning an offshore facility.

Further, the plan must take into consideration:

- technical, security, safety, environmental and economic aspects; and
- an evaluation of the impact on fisheries and navigation.

The NRA may grant exemptions from the requirements regarding the contents of the plan and may also require additional information and evaluations to those stated in the plan.

The offshore installation will normally be removed wholly or partly. The NRA can, however, agree to its continued use for the exploration and production of hydrocarbons or other kinds of usage. If there is reason to assume that a licensee does not have the financial ability to pay for the cost of decommissioning an offshore installation, the NRA can at any time demand that the licensee prove their ability to pay or provide necessary guarantees.

F. Renewable energy

F.1 Renewable energy

Iceland is unique given the high level of electricity and heat being generated from renewable sources. The total energy consumption originating from RES in Iceland is about 76%. Electricity is almost entirely generated from renewable sources – 71% from hydro and 29% from geothermal. As a result, Iceland is one of the most sustainable countries in the world regarding its energy consumption. The unique position of the Icelandic energy market is demonstrated in legislation where, under Regulation no. 1040/2005, it is stated that Generation Licences (see section A.5) for building electricity plants can only be granted for the exploitation of RES.

The Renewable Energy Directive was implemented into Icelandic law with Act no. 30/2008, which originally implemented the Promotion of RES Directive. Act no. 30/2008 was amended by Act no. 81/2012, effective from 19 June 2012, whereby the TSO was authorised to issue green certificates under the Renewable Energy Directive. As a result of the amendment, Icelandic electricity generators can now sell their green certificates on the European green certificates market. The updated Renewable Energy Directive no. EU2018/2001, is yet to be implemented.

F.2 Renewable pre-qualifications

In Iceland, renewable energy projects are not carried out based on auction.

F.3 Biofuel

The Biofuel Directive has been incorporated into the EEA Agreement by a decision of the EEA Joint Committee dated 30 October 2015. The Biofuel Directive was implemented in Iceland by a regulation on fuel quality dated 11 November 2016.

Research has also shown that greenhouse gas ("GHG") emissions of the Icelandic ship fleet could be reduced by 70% by using biofuels.[12] However, the biofuel in question is a first-generation biofuel such as vegetable oil. There is still debate as to whether the use of such biofuels is in fact benefiting the environment.[13] The research will nevertheless continue under the supervision of the Ministry of Industry and Ministry of Fisheries, and the ministries believe that the outcome could be globally beneficial.

F.4 Energy efficiency

Although the Energy Performance of Buildings is part of the EEA Agreement, it does not apply in Iceland. Iceland was granted an exemption due to special features of the Icelandic energy market.

The directive was incorporated into the Icelandic legislation by amendment of Act. no. 72/1994, dated 28 January 2015.

Iceland has transposed the Ecodesign Requirements for Energy Related Products Directive and relevant implementing legislation by Act no. 42/2009.

Iceland implemented the Energy Efficiency Labelling Programme for Office Equipment Regulation with Regulation no. 819/2010.

The Promotion of Cogeneration Directive has been transposed into Icelandic legislation through Act no. 80/2010, amending Act no. 30/2008 on the guarantee of origin of electricity generated from RES.

G. Climate change and sustainability

G.1 Climate change initiatives

In June 2020, Iceland issued a Second Edition of its Action Plan, describing governmental actions to reduce GHG emissions by 2030. The Action Plan is Iceland´s contribution to the objectives of the Paris Agreement and achieving the UN Sustainable World Goals, with emphasis on goals no. 8 (decent work and economic growth), 11 (sustainable cities and communities), 12 (responsible consumption and production), 13 (climate action), and 17 (partnership for the goals). The aim of the plan is to reduce emissions of GHGs and to lay the foundation for the goal of carbon neutral Iceland in 2040.

The Action Plan is a holistic plan consisting of 48 concrete measures, thereof 15 new measures that have been added since the previous version of the Plan. The government has emphasised the need to start implementing the measures quickly and the implementation of 28 measures has already started.

The Action Plan is divided into sections depending on how the measures are linked to Iceland´s international commitments as well as from which sources the emissions originate. There is more focus on low-carbon commute, such as walking and cycling, waste management gets more attention than in the first version and there is emphasis on measures where the public sector acts as a role model.

Iceland places special emphasis on the melting of glaciers due to global warming, which will continue to increase in the future. The melting will have a far-reaching impact on the management of earth's water supply and sea level. Amongst other things, this was a point of emphasis on behalf of Iceland at the UN Climate Change Conference 2019 (COP25).

G.2 Emission trading

Icelandic legislation on GHG emissions was almost non-existent before 2006, when Act no. 107/2006 on the Registration of Emission of Greenhouse Gases was passed. This statute has since then been replaced with Act no. 65/2007 on GHG emissions and later with the Climate Change Act no. 70/2012 (the "CC Act"). Act no. 65/2007, which aimed to fulfil the country's obligations under the Kyoto protocol, was amended by Act no. 64/2011, effective from 10 June 2011, whereby the EU Emissions Trading System Directive ("EU ETS") and the Aviation EU ETS Directive were implemented. However, very few domestic industries were covered by that amendment and the scheme was not fully implemented until the passage of the CC Act. Aviation became part of the scheme on 1 January 2012 and several other industries became part of the scheme from the beginning of 2013, for example aluminium smelting, ferrosilicon production and rock wool production. It is foreseeable that the scheme will cover 40% of all GHG emissions within a few years.[14] With the CC Act, Iceland has fully implemented the New EU ETS Directive. Iceland has also adopted the EU ETS Trading Regulation, amending the CC Act.

Another important object of the CC Act is to implement an overall legislative framework on climate change issues. The CC Act includes an obligation on the government to issue a climate change strategy that must be revised every three years and must be subject to a cost estimate in this time frame.

G.3 Carbon pricing

In 2018, effective carbon rates in Iceland consisted of fuel excise taxes and, to a smaller extent, of carbon taxes and of permit prices from the EU ETS. Iceland priced about 80% of its carbon emissions from energy use and about 41% were priced at an Effective Carbon Rate above €60 per tonne of carbon dioxide ("CO_2"). Emissions priced at this level originated primarily from the road transport sector. Most unpriced emissions were from the industry sector and the road sector.

Iceland has a general tax on carbon in place, as per the Act on Environmental and Resource Taxes no. 129/2009, which covers all fossil fuels. The tax was increased by 50% in the beginning of 2018, again by 10% in 2019 and again by 10% in the beginning of 2020. Along with general increasing due to price level changes, the carbon tax has almost doubled since the beginning of 2018.

G.4 Capacity markets

In Iceland, Capacity Markets are not operated. Iceland has very little volatile generation capacity, and water reservoir levels can be projected with relatively high certainty. Although potential wind generation in the future will make it more volatile, wind power shares are expected to be quite small compared to the flexible hydropower sources. On the demand side, there is little electric heating and few EVs, so sudden big changes in demand are unlikely.

In September 2020, a workgroup with the Ministry of Industries and Innovations delivered a report on Secured Access to Electricity in Iceland. The group pointed out that the Electricity Act does not clearly state the goal of Secured Access of the public to electricity.

The group proposed amendments to the Electricity Act with regards to observing Secured Access of the public to electricity as a National Matter and that Secured Access to Electricity be defined in the Electricity Act, based on four criteria:

1. Energy Policy for five to ten years that includes long-term energy supply;
2. Delivery Security for two to five years;
3. Production Safety for one year; and
4. Real-time Security.

The Minister of Industries and Innovations proceeded with a bill before parliament, where the aim is to define Secured Access of the public to electricity. The bill also proposes revisions on Regulation no. 1048/2004 on Quality and Transportation Security of Electricity.

H. Energy transition

H.1 Overview

Iceland has in recent decades achieved success in energy transition in its district heating and electricity systems, where fossil fuels have been replaced by renewable energy (geothermal and hydropower). This earlier energy transition has proven advantageous for the country and macroeconomically beneficial. The population has enjoyed improved energy security, lower energy prices and a cleaner environment.

The energy transition is now in progress in land, sea, and air transport. With the e-transition, fossil fuel will be replaced by RES. The long-term objective of the energy transition, as per Iceland's Energy Policy to the year 2050, is for Iceland to no longer rely on fossil fuels and to meet all the energy needs of the country using RES.

Parliamentary resolution on energy transition in on-land and offshore transport was approved by parliament on 31 May 2017. The resolution proposes an action plan to increase the share of domestic RES at the expense of imported fossil fuels. The energy transition will result in increased energy efficiency and energy security, as well as a reduction in foreign currency expenses and GHG emissions.

The objective of the energy transition is to increase the share of renewable energy in on-land transport from 6% in 2016 to 10% by 2020 and 40% by 2030. An additional goal is to increase the share of renewable energy in the fisheries sector from 0.1% in 2016 to 10% by 2030.

Economic incentives and concessions will encourage consumers and businesses to choose renewable energy options. Development of infrastructure, such as charging stations outside urban areas, will support the transition. Increased energy efficiency of fuel, whether fossil or renewable, will contribute to energy savings.

The action plan involves further measures, eg, cooperation and research, development, innovation and international cooperation, as per Parliamentary Resolution no. 18/146.

H.2 Renewable fuels

Hydrogen

There is no separate strategy for Hydrogen in Iceland. Iceland's Energy Policy to the year 2050 has the underlying guideline of sustainable development but does not have a separate sub-policy regarding hydrogen.

However, Act no. 40/2013 on Renewable Fuels in Land Transport covers all types of RES, including hydrogen, with regards to fuel production for land transport. The Act came into force in 2015 and imposed obligations on fuel retailers with regards to renewable origin of fuels for transports on land. Requirements have also been set out for information and certificates of origins for manufacturers and dealers, showing that fuel is renewable. Act no. 70/2012 on Climate Change also covers hydrogen, aiming at reducing GHG emissions with a general approach.

Some parties of the energy industry are looking into experimenting with hydrogen. However, they seem to be awaiting policies from the government to be able to act unitedly. One of the five major electricity producers in Iceland, Landsvirkjun, is working on a hydrogen production project in one of its hydropower-plants[15]. The company is also reviewing the possibility of exporting hydrogen through Rotterdam, the biggest energy port in Europe.

Ammonia

There are no ammonia activities in Iceland as ammonia is not a part of Iceland's Energy Policy and there is no separate strategy or legislative framework for ammonia as a renewable fuel.

H.3 Carbon capture and storage

The CCS Directive is relevant to the EEA and was adopted into the EEA Agreement by the EEA Joint Committee on 15 June 2012. The directive was implemented into Icelandic legislation by amendment by Act no. 62/2015.

Research has shown that afforestation and reforestation have considerable carbon capture possibilities.[16] Although such projects could only counterbalance the country's carbon emissions to some extent, it is estimated that Europe could theoretically store at least 4,000 billion tonnes of CO_2 in rocks.

CarbFix is an academic-industrial partnership which has developed a novel approach to capture and store CO_2 by its capture in water and its injection into subsurface basalts. For further information on CarbFix, see Iceland recent developments chapter.

H.4 Oil gas platform electrification

Iceland does not have oil or gas platforms.

H.5 Industrial hubs

Reykjanes Resource Park is an example of an industrial hub in Iceland. The Resource Park is enabled by the unique conditions of geothermal power plants which deliver multiple resource streams to a varied range of businesses: the 'Blue Lagoon spa', cosmetics manufacturers, biotechnology companies, and aquaculture. The Resource Park offers renewable power and sustainable effluent from the geothermal power plants, combined with efficient logistics to mainland Europe and North America.

H.6 Smart cities

Reykjavík, the capital city of Iceland, aims to use information, communications, and telecommunications technology to improve quality of life in a sustainable way. Reykjavík gathers and combines data from different databases related to the infrastructure of the city and uses it to improve services, quality of life and environment. In this way, Reykjavík is heading towards becoming a 'smart city'.

As an example of smart projects of the city is 'Better Reykjavík', where citizens are given the chance to present their ideas on issues regarding services and operations of the City of Reykjavík via an online consultation forum. Also, the participatory democracy portal *Hverfið mitt* (My Neighbourhood), is one of the city's first smart projects, enabling city residents to present their ideas, and vote on ideas to be implemented. The result is decision-making based on the needs of city residents.

In 2014, an app was launched for public transportation city buses, which has been a great success. Additionally, the Land Information System of the Reykjavík area, covering the Reykjavík municipality area of 270km^2, is accessible online via a joint GIS-system[17] – The Reykjavik Land Information System (LUKR Outsourcing Website). The LUKR website stores important geographic information about streets, buildings, landscapes, parking and more in Reykjavik. Information is free of charge and in digital form.[18]

I. Environmental, social and governance (ESG)

The ESG criteria is part of the Energy Policy to the year 2050 (the "Energy Policy"). As part of the Energy Policy, future energy production is to be found a place in planning, where the greatest consensus can be achieved regarding location and environmental impact is to be minimised to the extent possible. As an example, environmental factors are to be considered when deciding on energy transmission and distribution systems.

Act no. 106/2000 on Assessment on Environmental Impact provides for assessment of probable environmental impact of certain projects. The impact of a project is analysed and assessed, and the conclusion of the assessment is considered when granting permits for the project in question. If a permit is to be granted, the result of the assessment will be used in the final implementation of the project, so that its negative impact on the environment can be reduced as much as possible. Project developers are responsible for the environmental assessment being performed and the relevant municipality grants permits based on the assessment. Governmental bodies can comment on certain elements of the assessment as relevant to their operation, as well as the public is given an opportunity to express its views during public consultation. The National Planning Agency is responsible for overseeing environmental assessments and general enforcement of the Act on Assessment on Environmental Impact.

Social factors are also part of Iceland's Energy Policy, under which all Icelanders are to have equal access to energy, and the benefits of energy resources will accrue to local communities and the whole nation.

Endnotes

1. Article 18 Electricity Act.
2. See www.efta.int/media/documents/legal-texts/eea/other-legal-documents/adopted-joint-committee-decisions/2017%20-%20English/093-2017.pdf.
3. Such as the Planning Act no. 123/2010, the Act on Hygiene and Pollution Control no. 7/1998, Act on Environmental Impact Assessment no. 106/2000 and Natural Resources Act no. 57/1998.
4. Act no. 48/2011.
5. Article 8(1) Electricity Act.
6. Articles 9 and 16 Electricity Act.
7. Article 5(3) Electricity Act.
8. Article 4(2) Electricity Act.
9. Article 14 Electricity Act.
10. Guide to Application Procedures, Second Licensing Round on the Icelandic Continental Shelf, Licences for Exploration and Production of Hydrocarbons, Orkustofnun, see www.nea.is/media/2nd-round/guide_to_applications_2nd_round-26032012.pdf.
11. The first two hydrocarbon exploration licences in the Dragon Area were issued for a period of seven years, with the possibility of extending the period up to a maximum of 16 years. The third licence was issued for a period of 12 years.
12. Climate Action Plan (*Aðgerðaáætlun í loftslagsmálum*). Ministry for the Environment, p.28.
13. Ibid., p.29.
14. Climate Action Plan (*Aðgerðaráætlun í loftslagsmálum*). Ministry for the Environment, p.13.
15. Landsvirkjun's announcement announcement, see www.landsvirkjun.com/news/green-hydrogen-is-an-environmentally-friendly-energy-carrier.
16. Carbon capture in plants and soil in Iceland (*Kolefnisbinding í gróðri og jarðvegi á Íslandi*). Þórðardóttir, Þórey Dalrós. Reykjavík 2004, p.8.
17. See further information regarding Iceland's basic data here: www.government.is/topics/information-society/geodata.
18. See further information on the LUKR website: www.reykjavik.is/en/landupplysingar.

Energy law in Ireland

Recent developments in the energy sector in Ireland

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Ireland is on a legally binding path to net zero emissions by no later than 2050, and to a 51% reduction in emissions by 2030, following the enactment on 23 July 2021 of the Climate Action and Low Carbon Development (Amendment) Act 2021 (the "Act").

The Act provides a framework for Ireland to meet its EU and international commitments to address climate change. Under the Act, Ireland is committed to pursuing and achieving transition to a climate resilient, biodiversity rich, environmentally sustainable and climate-neutral economy no later than 2050.

The Act sets out, among other things, that Government ministers will be responsible for achieving the legally binding targets for their own sectoral area and that each minister will be accountable each year for their performance towards sectoral targets and actions before an Oireachtas committee. The Oireachtas is the bicameral parliament of Ireland.

The Act also sets out that the Government must publish a climate action plan for key sectors in Ireland. The published climate action plan must be updated annually with actions specific to key sectors also updated annually. Local authorities must also prepare individual climate action plans to be updated every five years. The local authorities' climate action plans must include mitigation and adaptation measures and the authorities' development plans must be aligned with their climate action plan.

Climate action plan 2023

The Climate Action Plan 2023 ("CAP 2023") sets out, among other things, the current state of play in 'six vital high impact sectors' in Ireland, and the measures to be implemented to achieve target reductions in emissions in each of these key sectors by 2030. In relation to these six sectors, the plan sets out individual targets for reduction in emissions in respect of each sector.

The six key sectors, and the respective target emissions' reduction by 2030 are: (i) powering renewables, with a target reduction of 75%; (ii) commercial/public buildings, with a target reduction of 45%, and residential buildings with a target of 40%; (iii) transport with a reduction target of 50%; (iv) making family farms more sustainable with a reduction target of 25%; (v) industry and enterprise with a target of 35%; and (vi) land use, for which an exact reduction target at date of publication was not set.

The plan also outlines measures on how these target reductions are to be achieved, which include Government driving policies to reduce carbon emissions and initiatives such as supporting farmers to continue to produce food while seeking to diversify income through eg energy generation and forestry.

For powering renewables, the measures set out under the CAP 2023 to achieve the targeted reduction of 75% emissions by 2030 include accelerating the delivery of onshore and offshore wind and solar, with 9GW onshore wind, 8GW solar and at least 7GW offshore wind to be delivered by 2030. The measures also anticipate 2GW of offshore wind to be earmarked for the production of green hydrogen. Other measures include the support of at least 500MW of local community based renewable energy projects, an increase in the levels of new micro-generation and small-scale generation, the phase out of coal and peat in electricity generation and the introduction of a green electricity tariff. The tariff is to be developed in 2025 and is aimed at incentivising the use of lower cost renewable electricity at times of high wind and solar generation.

Wind energy is the primary source of renewable energy in Ireland currently. In 2022, Ireland's wind farms provided 34% of Ireland's electricity demand, a total of 13,213GWh, equivalent to the electricity consumption of about three million Irish homes; to date, there are about 300 wind farms in Ireland.

To achieve the 40%-45% target emissions reduction in buildings, various measures are set out in relation to energy efficiency which include increasing retrofitting of dwellings to 120,000 by 2025 and 500,000 by 2030, installing heat pumps into 45,000 existing and 170,000 new dwellings by 2025, and up to 400,000 existing and 280,000 new dwellings by 2030. The measures also envisage the generation of up to 0.8TWh of district heating by 2025, increased to up to 2.5TWh by 2030.

For transport, it is envisaged that, among other things, by 2030 nearly one in three private cars will be electric vehicles. In respect of making farms more sustainable the measures include expanding the indigenous biomethane sector through anaerobic digestion and, by 2030, reaching up to 5.7TWh of biomethane. To achieve the 35% target reduction of emissions in the business and enterprise sector it is envisaged that by 2030 there will be a reduction by at least 30% in the use and production of carbon construction materials in Ireland, final consumption of fossil fuel will be reduced to 45% by 2025 and further by 2030, and the increase in carbon neutral heating will increase from 50%-55% in 2025 to up to 70%-75% by 2030. The CAP 2023 sets out that, for changes in land use, there will be a first phase review which will then inform Government on how land is being used and how it can be used more effectively. Among the changes in land use envisaged in the CAP 2023 are an increase in annual afforestation rates to 8,000 hectares annually from 2023 onwards, and the rehabilitation of 77,600 hectares of peatlands. Other actions under the CAP 2023 include measures such as an enhanced new forestry programme to include a range of forest creation measures and planting of small native areas, and also encouraging the use of renewables in the petroleum refining process.

Carbon budgets

Under the Act, the Climate Change Advisory Council is enabled to propose carbon budgets to match the Government's climate change targets and meet with its international obligations. The Climate Change Advisory Council is an independent advisory body tasked with assessing and advising on how Ireland is making the transition to a low carbon, climate resilient and environmentally sustainable economy by 2050.

The Act provides that the first two five-year carbon budgets proposed by the Climate Change Advisory Council should equate to a total reduction of 51% over the period to 2030, relative to a baseline of 2018. In 2022, Ireland introduced economy wide carbon budgets, which came into effect on 6 April 2022, and sectoral emissions ceilings, which were approved on 28 July 2022. The CAP 2023 implements a carbon budget programme that comprises of three five-year budget periods (2021-2025; 2026-2030; 2031-2035 (provisional)) with sector-specific emissions ceilings operating within the parameters of the budgets.

A carbon budget represents the total amount of emissions (CO_2/tonnes equivalent) that a county or region may emit during a specific time period. A sector ceiling represents the maximum amount of greenhouse gas emissions permitted within different sectors of the economy during a carbon budget period. The sectors include electricity, transport, built environment - residential, built environment - commercial, industry, agriculture, land use, land-use change and forestry (LULUCF), and other sectors (eg gases, waste and petroleum refining).

National energy security framework

From the onset of the Russian invasion of Ukraine and the resulting impact on global energy markets, the Irish Government has sought to address the negative impacts of higher energy prices on consumers, society and the economy. In April 2022, the Government launched the National Energy Security Framework, which encompasses three key areas of action: domestic energy consumer protection, with a specific focus on the most vulnerable residential consumers, near term energy security supply, which specifically focused on winter 2022/2023, and reducing national dependency on imported fossil fuels in the context of the phasing out of Russian energy imports across the EU.

In January 2023, the Oil Emergency Contingency and Transfer of Renewable Transport Fuels Functions Bill 2022 (the "Bill") was approved by the Government. According to the Government, the main purpose of this Bill is to strengthen the Government's ability to manage stocks in the unlikely event of a curtailment of oil supplies. The Bill provides for more clarity around the powers of the Minister of Environment, Climate and Communications and how quickly they can be deployed to control the supply and distribution of fuel in an emergency. The Bill puts all aspects of oil emergency planning on a statutory footing and, among other things, establishes a register of oil suppliers to ensure fast communication to retailers.

Programme for government

In July 2022, the Programme for Government set a target for 7GW of offshore wind by 2030; the initial wind target for 2030 was 5GW.

Wind power is projected to provide an additional 2.6GW by 2027, and several solar photovoltaic (PV) and biomass cogeneration plants are also expected to come onstream. Fossil fuels continue to dominate and accounted for about 72% of all energy used in Ireland in 2021. The Sustainable Energy Authority of Ireland ("SEAI") found that oil remained the dominant source of residential energy demand in 2021, and accounted for about 41% of all home energy use, followed by electricity at 25% and gas at 19%. The SEAI also reported that in 2021 due to a low wind year for renewable generation, Ireland used more coal and oil for electricity generation, the result of which increased the carbon intensity of Ireland's electricity by 12.5%.

Maritime area planning

The Maritime Area Planning Bill (the "MAPB") was enacted in December 2021. The MAPB ensures that the consent mechanism for offshore renewable energy projects complies with EU environmental assessment obligations and enables Ireland to deliver projects conducive to national climate targets for 2030. It reshapes the consenting regime by providing that two separate consents will be required for the development of offshore renewable energy projects. One consent is needed to occupy the maritime area, ie a Maritime Area Consent ("MAC"), and another to allow development of that area, ie a development consent (planning permission).

A MAC must be obtained first, following which the development permission can be sought under the Planning and Development Act 2000. The MAPB also established the Maritime Area Regulatory Authority (MARA), which is a new regulatory authority responsible for the granting of MACs and the enforcement of the new regulatory regime. For projects that already have a foreshore lease or licence under the Foreshore Act 1933, the MAPB provides that a holder of a foreshore authorisation does not need to apply for a MAC until its foreshore authorisation is going to expire, or unless it wishes to amend its currently authorised activity or occupation of the maritime area.

Interconnectors

The construction of the Greenlink 500MW interconnector between Ireland and the UK is underway. The project reached financial close in March 2022 and is expected to be operational in 2024. The project has been designated a European Project of Common Interest ("PCI"), which means it can benefit from improved regulatory conditions and EU financial assistance from the Connecting Europe Facility (CEF). The project developer and promoter is Element Power, which is also a shareholder along with its owner Hudson Sustainable Investments, and Partners Group, a private markets investor. The Greenlink interconnector is a bi-directional power system which will be capable of continuously transferring 504MW of power to/from the 220kV substation at Great Island in Ireland to/from the 400kV substation at Pembroke in Wales, UK.

The North-South interconnector, which is a 400kV overhead line that will connect the electricity grids of Northern Ireland and Ireland proposed by NIE Networks and EirGrid, is the second high-capacity transmission link between Ireland and Northern Ireland. The North-South interconnector has received planning approval in Ireland and Northern Ireland and is expected to be commissioned during 2025. The interconnector is expected to become fully operational by 2026.

The Celtic HVDC 700MW interconnector is being constructed between Ireland and France and is due to be completed in 2026. The project has been designated a PCI and is being jointly developed by EirGrid, the Irish transmission system operator ("TSO"), and Réseau de Transport d'Électricité (ie RTÉ), the TSO in France. In January 2019, the energy regulator in Ireland, ie the Commission for Regulation of Utilities, decided to progress the project to stakeholder consultation, which resulted in a positive progression of the project. In April 2019, EirGrid launched a public consultation to shortlist the options for the proposed landfall locations for the project on the coast of East Cork and the proposed location zones for a converter station in East Cork. In November 2020, EirGrid announced that the interconnector power cables will reach landfall in Ireland at Claycastle Beach in Youghal, County Cork. A further public consultation on the Foreshore Licence Appropriate Assessment was launched in March 2022.

The interconnector's application for a foreshore licence in Ireland was granted in 2022 along with a marine licence to undertake the installation of the portion of the interconnector that is within the UK Exclusive Economic Zone ("EEZ"). EirGrid and RTÉ signed the key technical and financial agreement in November 2022 and the interconnector is expected to go live in 2026.

Further interconnector projects include the MaresConnect interconnector, which is included in European Network of Transmission System Operators for Electricity (ENTSOE) Ten Year Network Development Plan 2020. The MaresConnect interconnector will run between Ireland and Great Britain ("GB") and is part of a wider project that includes a sea water pumped hydro station. This interconnector project is aimed to achieve an increase of 750MW of cross border transmission capacity of green energy between Ireland and GB.

Offshore wind auction

The provisional results for Ireland's first offshore wind auction under the offshore renewable electricity support scheme ORESS 1 were published in May 2023. Under the scheme, a capacity of 12,117GWh for four provisionally successful projects was awarded. The projects are: the North Irish Sea Array (NISA) (500MW), Dublin Array (824MW), Codling Wind Park (1,300MW) and Sceirde Rocks (450MW). The average strike price was €86.05/MWh Under the scheme, the winning projects will have to produce power before 2032.

In furtherance of its commitment to the development of offshore wind, the Irish Government plans to develop a National Industrial Strategy for Offshore Wind; the strategy is expected to be published in 2024.

Overview of the legal and regulatory framework in Ireland

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Ireland is fully liberalised for both the generation and retail markets and, since April 2011, all suppliers are free to offer electricity prices without consultation or the prior approval of the energy regulatory, ie the Commission for Regulation of Utilities ("CRU") (previously named the Commission for Energy Regulation ("CER")). Competition continues to increase and the number of players in both the generation and retail markets is growing; state-owned companies however continue to play a dominant role in these markets.

The Single Electricity Market ("SEM") was integrated in 2018 in order to be consistent with the European target model[1]; the new integrated SEM ("iSEM") went live on 1 October 2018. The SEM is the all-island wholesale electricity market with one set of rules and regulations that cover the two jurisdictions of Ireland and Northern Ireland; the SEM has been in place since 2007 (see section C.1).

The Government's commitment to decarbonise the power sector includes the phasing out of three peat-fired generation plants, which together account for 346MW, and ceasing to use coal for the only coal-fired power station in Ireland (Moneypoint power station) by 2025.

EirGrid plc, the state-owned electric power transmission operator ("EirGrid"), has noted that several older generating stations are also due to be decommissioned, mainly due to emissions restrictions. Two generating stations with a total capacity of 353MW were closed in 2018 and an additional 786MW of capacity is due to cease operations by end of 2023. If all proposed decommissioning proceeds, about 2.4GW of installed thermal capacity will be lost by the mid-2020s.[2]

Key market players

The Electricity Supply Board ("ESB") is a state-owned vertically integrated company that owns about 47% of the electricity generation capacity. The company's assets include the Moneypoint power station (915MW), two peat-fired power stations, several gas units and increasing numbers of renewable energy generation. The ESB was previously involved in generation, transmission and distribution, however, pursuant to the Third Electricity Directive, the company has been unbundled. The ESB continues to have a statutory monopoly on the ownership of Ireland's transmission and distribution systems. Under the Electricity Regulation Act 1999 ("Electricity Act"), state-owned EirGrid is the only body authorised to operate, maintain and develop the Irish electricity transmission network. EirGrid took over the role of transmission system operator ("TSO") on 1 July 2006. State-owned ESB Networks DAC is the only body authorised to operate, maintain and develop the Irish electricity distribution network. ESB Networks DAC was vested as the distribution system operator ("DSO") in Ireland on 1 January 2009.

Key market players in electricity generation in Ireland include SSE Airtricity Limited, Viridian Energy Limited, Tynagh Energy Limited, Brookfield Renewable Ireland Limited and the semi-state-owned Bord na Móna. The ESB is the largest player in the SEM, with about 40% of generation held in 2021, SSE Airtricity held about 15% and Viridian (Energia) held about 14%. Smaller players include the privately owned Tynagh and Aughinish, and the semi-state-owned Bord na Móna, each of which held about 5% or less generation.

As of the end of 2020, the largest market share in domestic electricity supply was held by Electric Ireland, which is the supplier arm of the ESB, with 50.6%, followed by Bord Gáis Energy (Centrica) with 15.9%, SSE Airtricity with 10.7%, Energia with 8.6%, PrePayPower with 7.6%, Panda with 2.5% and Pinergy with 1.3%.[3]

The largest players in Ireland have a presence in both the generation and supply markets. The ESB (Electric Ireland), Centrica (Bord Gáis Energy), SSE (Airtricity) and Viridian (Energia) all hold renewable and conventional generation assets while maintaining a considerable presence in the retail market.

Regulatory authorities

The Department of Environment, Climate and Communications ("DECC"), (previously, the Department of Communications, Climate Action and Environment ("DCCAE")), is the main government department with responsibility for energy policy. DECC determines policy on energy security, competitiveness and sustainability. The Minister for the Environment, Climate and Communications (the "Minister") has overall policy responsibility for the energy sector.

The primary legislation governing the electricity sector in Ireland is the Electricity Regulation Act 1999 (the "Electricity Act") under which the CRU was established. The CRU is the independent regulator of electricity and natural gas. The CRU is also Ireland's designated national regulatory authority ("NRA") for the purposes of the Third Electricity and Gas Directives. The CRU, which was originally the CER and changed its name to the CRU in 2017 to reflect its broadening remit to regulate energy, energy safety and water. The CRU has responsibility for electricity and gas regulation and licensing, which includes electricity generation, electricity and gas networks, electricity and gas supply activities, and the regulation and promotion of electrical, gas and petroleum safety. The CRU also oversees market arrangements, which includes approving changes to the electricity and gas industry codes, regulating permitted revenues and tariffs for incumbents, settling disputes, ensuring a high standard of protection for end customers, and cooperating with other NRAs and the European Commission (the "Commission"). The CRU can also take any necessary actions in power or gas emergency situations.

The CRU jointly regulates the all-island wholesale SEM (the iSEM) with the Utility Regulator, its Northern Ireland counterpart, as part of the Single Electricity Market Committee ("SEMC"). The SEMC is the decision-making authority that aims to promote competition in the sale or purchase of electricity through the SEM.

Legal framework

The principal legislation governing the electricity industry is the Electricity Act, ie the Electricity Regulation Act 1999, as amended. The Electricity Act provides for the establishment of a regulatory framework that introduces competition in generation and supply.

Other legislation governing the Irish electricity sector includes:

- Electricity (Supply) Act 1927, which established the ESB;
- European Communities (Internal Market in Electricity) Regulations 2005;
- Energy (Miscellaneous Provisions) Act 2006 and the Electricity Regulation (Amendment) (Single Electricity Market) Act 2007, which provide the legal basis for the SEM in Ireland, including the establishment of a committee for the SEM;
- European Communities (Renewable Energy) Regulations 2014, which transpose the Renewable Energy Directive, as supplemented by the Sustainable Energy Act 2002 (Section 8(2)) (Conferral of Additional Functions - renewable Energy) Order 2012; and
- Energy Act 2016, which provides for enhanced enforcement powers for the CRU, among other things.

To address the security of supply issues facing Ireland, in July 2022, the Government enacted the EirGrid, Electricity and Turf (Amendment) Act 2022.[4] This Act allows EirGrid to acquire electricity generation plants that it sells to an electricity generation company. According to the Act, EirGrid would not operate the plant but would instead enter into an agreement with the generation company to operate it. Funds to achieve this would come from Government. The Act provides for the increase of the amount of money that EirGrid may borrow from the Government and for that purpose amend the Electricity Regulation (Amendment) (EirGrid) Act 2008.

Implementation of EU electricity directives

The First Electricity Directive has been transposed into Irish law through the European Communities (Internal Market in Electricity) Regulations 2000. The Second Electricity Directive has been transposed and further implemented by the European Communities (Internal Market In Electricity) (Electricity Supply Board) Regulations 2008, which transpose and further implement the Second Electricity Directive.

The Third Electricity Directive has been transposed through the European Communities (Internal Market in Electricity) Regulations 2010 (S.I. 450 of 2010) ("Internal Market in Electricity Regulations"), which give effect to certain provisions of the Third Electricity Directive and mark the first step in its full transposition. The Internal Market in Electricity Regulations include provision for, among other things, enhanced security of supply, a new role for the CRU in monitoring and regulating the electricity retail market and taking action, increased levels of consumer protection, stronger independent regulation, the licensing of a public electricity supplier and designation of a supplier of last resort.

The Minister introduced new legislation on the redesigned Energy Efficiency Obligation Scheme ("EEOS")[5]. The scheme has been redesigned in response to amendments to the EU Energy Efficiency Directive ("EED") and the Government's climate priorities. The new EEOS Regulations establish a new scheme from the year 2023 for the achievement of energy savings required under Article 7 of the EED. The EEOS places a legal requirement on larger energy companies to help energy users save energy. This can be achieved by supporting the energy user (financially or otherwise) to implement energy saving practices or to carry out energy upgrades in their property.

Ireland's transmission network operates under the independent system operator ("ISO") unbundling model. The ESB retains ownership of the network assets but EirGrid is responsible for the operation and development of the transmission system. EirGrid has been certified as an independent transmission operator and is the TSO; the ESB continues to own the transmission assets and must fund, maintain and construct the transmission network as necessary.

A.2 Third party access regime

The Electricity Act governs access to transmission and distribution systems, arrangements and agreements relating to the transmission system (including the Northern Ireland transmission system), and interconnectors. Eligible customers, or those holding a licence or authorisation, can apply to EirGrid for connection to the transmission system and to ESB Networks DAC for connection to the distribution system.

From time to time, the CRU can issue directions to the system operator specifying the terms of connection. Such directions may concern the terms and conditions of a connection offer or the percentage of costs to be incurred by the relevant system operator and connecting parties. A system operator can only refuse to make a connection offer if the CRU is satisfied that the connection is not in the public interest, that the connection would be a breach of the Electricity Act or its regulations, the grid code, or a condition of a licence or authorisation, or if the applicant refuses to be bound by the terms of the grid code. The grid code is the technical document under which the rules that govern the operation, maintenance and development of the transmission system are established. The grid code also sets out the procedures that govern the actions of the transmission system users.

Holders of licences to transport electricity and maintain interconnectors must offer access to the interconnector. Such access must be based on published non-discriminatory terms that have been approved by the CRU. Interconnector operators can refuse to allow access if they can demonstrate to the CRU that such access would not be in the public interest or would be in breach of the Electricity Act, its regulations, the grid code, distribution code, or the operator's licence or authorisation.

A.3 Market design

The SEM has been in operation since 2007. The market operator role is performed by the Single Electricity Market Operator ("SEMO"), which is a joint venture between EirGrid and the System Operator for Northern Ireland ("SONI"); both EirGrid and SONI are part of the EirGrid Group. The SEM was brought into compliance with the European Union ("EU") Third Energy Package when the new iSEM went live on 1 October 2018.

The SEM is now coupled with other EU Member States via Great Britain and uses single day-ahead market coupling. The SEM consists of five markets, ie forward, day-ahead, intraday, balancing and capacity. These new and more competitive trading arrangements allow for better use of existing infrastructure, and ensure interconnectors operate in the most efficient manner, especially for system balancing. The SEM is also expected to give investors clearer indications of the Irish market, and reward generators that are best meeting the market's requirements.

A.4 Tariff regulation

Under section 35 of the Electricity Act, the CRU determines the transmission use of system charges ("TUoS") on the basis of statements prepared for the CRU's approval by EirGrid. TUoS is the system of charging for transporting power in bulk across the power system, ie the high voltage transmission system, and are separate to the payments made by customers when buying energy from suppliers or generators. The TUoS charges apply to generators on an all-island basis, demand customers in Ireland, ie larger commercial or business users of electricity, and suppliers in Northern Ireland. The TUoS charges are also paid by customers that rely on the transmission system.

A.5 Market entry

An authorisation to construct or reconstruct a generating station is required to construct a generation facility. The authorisation is issued by the CRU under section 16 of the Electricity Act. A generation licence is required to operate a generation facility, such licence is issued by the CRU under section 14(1)(a) of the Electricity Act. Suppliers of electricity must also be licenced by the CRU and such licences can be granted to eligible customers, which is effectively all customers, as the market is fully liberalised.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Under the Electricity Act (section 39), the Minister must direct the CRU to impose public service obligations on holders of electricity licences. These obligations were mainly due to security of supply concerns before the SEM was established.

Smart metering

ESB Networks announced the first phase of a €1.2 billion national electricity and gas meter programme in January 2019. The programme began in 2019 and a total of 2.4 million meters are due to be in place by 2024, with the intention that every home and business in Ireland will have a smart meter.

The meter replacement programme will upgrade electricity meters to smart-ready technology and the programme is considered a key element of the drive to combat climate change, allowing electricity suppliers to offer smart energy services and support the change to a low-carbon electricity system. The installation of the smart meters initially focused on replacing old meters. The smart meters provide information on consumption, and accurate and regular information on usage, seeing an end to estimated bills.

Electric vehicles

The Government aims to have one million EVs on the road by 2030 along with 1,500 electric buses in the public transport fleet.[7] As of February 2023, there were about 67,000 EVs and plug-in hybrids on Irish roads. The Government has also set a target to end the sale of cars powered only by fossil fuels by 2030.

A purchase grant of up to €5,000 is available towards the cost of buying a qualifying new battery EV ("BEV"), with up to €3,800 available for qualifying new commercial BEVs. BEVs have no tail pipe emissions of CO_2. A grant of €600 is also available for electric car owners to help with the purchase and installation of home charger systems.

The ESB has developed 1,200 public charge points across the island of Ireland, with about 900 of these in Ireland. Charging vehicles is free but charges are being applied on a phased basis.

The Government also proposes to develop the EV charging network to support the growth of EVs to at least 800,000 by 2030.

A.7 Cross-border interconnectors

Existing interconnectors

There are two HVDC electricity interconnectors between the island of Ireland and Great Britain, ie the 500MW HVDC Moyle Interconnector between Northern Ireland and Scotland, which was completed in 2003 and is owned by Mutual Energy, and the 500MW East-West interconnector between Ireland and Wales, which is owned by EirGrid Interconnector DAC.

There are three electricity interconnectors between the Northern Ireland grid and the Ireland grid; the Northern Ireland grid is operated by Northern Ireland Electricity Networks ("NIE Networks"). The Northern Ireland and the Ireland transmission systems are connected through a 275kV line with capacity reliance restricted to 100MW North to South and 200MW South to North. There are also two interconnectors with 120MW capacity each; however, these are mainly used to allow the two grid companies to provide mutual technical assistance.

Proposed interconnectors

NIE Networks and EirGrid have proposed the construction of the North-South interconnector, which is a 400kV overhead line that will connect the electricity grids of Northern Ireland and Ireland.

This, the second high-capacity transmission link between Ireland and Northern Ireland, has received planning approval in Ireland and Northern Ireland and is expected to be commissioned during 2025. The interconnector is expected to become fully operational by 2026.[8]

The Celtic interconnector is proposed to be constructed between Ireland and France. EirGrid submitted an investment request in September 2018 to the CRU for the Celtic HVDC 700MW interconnector project. The project has been designated a PCI and is being jointly developed by EirGrid, the Irish TSO, and Réseau de Transport d'Électricité (ie RTÉ), the TSO in France. In January 2019, the CRU decided to progress the project to stakeholder consultation, which resulted in a positive progression of the project. The Celtic interconnector is due to be completed in 2026.

ENTSOE's most recent Ten Year Network Development Plan 2020 notes a further interconnector project (MaresConnect) proposed from Ireland to Great Britain. This interconnector is part of a wider project that includes a sea water pumped hydro station.[9]

The construction of the Greenlink interconnector is underway. Greenlink is a new 500MW interconnector between Ireland and the UK, which is expected to be operational in 2024. The interconnector is a bi-directional power system which is capable of continuously transferring 504MW of power to/from the 220kV substation at Great Island in Ireland to/from the 400kV substation at Pembroke in Wales, UK.

The project has been designated a European Project of Common Interest ("PCI"), which means it can benefit from improved regulatory conditions and EU financial assistance from the Connecting Europe Facility ("CEF"). The project developer and promoter is Element Power, which is also a shareholder along with its owner Hudson Sustainable Investments, and Partners Group, a private markets investor.

CRU determines approach to cap and floor regime

Greenlink has secured 'cap and floor' regimes with both the regulators in Ireland, ie the CRU, and in the UK, ie Ofgem. Under the cap and floor regime, interconnectors earn revenue from the allocation of capacity. The floor is the minimum amount of revenue that an interconnector can earn and the cap is the maximum amount. If an interconnector does not receive enough revenue from its operations, its revenue will be 'topped up' to the floor level, with funds being transferred from the system operator to the interconnector. If an interconnector's revenue exceeds the cap, the interconnector will transfer the excess revenue to the system operator, which will in turn reduce transmission charges, ultimately reducing costs for the end consumer.

Ireland is the second jurisdiction outside Great Britain to adopt the cap and floor regime; Belgium has also adopted the regime.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Oil is the largest energy source in Ireland and accounts for about half of the total primary energy supply (about 45% in 2021). There is no indigenous oil production in Ireland and no oil pipelines with other countries. Ireland is therefore totally reliant on oil imports, and imports about 63% of its oil products from the UK. Ireland's crude oil imports are sourced from Norway, Denmark, the US, the UK and OPEC member countries. Refined products are sourced from the UK, the US, Sweden, the Netherlands, Norway, Belgium and previously Russia.

From the onset of the Russian invasion of Ukraine and the resulting impact on global energy markets, the Government has sought to address the negative impacts of higher energy prices on consumers, society and the economy. In April 2022, the Government launched the National Energy Security Framework, which encompasses three key areas of action: domestic energy consumer protection, with a specific focus on the most vulnerable residential consumers, near term energy security supply, with a specific focus on winter 2022/2023, and reducing national dependency on imported fossil fuels, in the context of the phasing out of Russian energy imports across the EU.

In January 2023, the Oil Emergency Contingency and Transfer of Renewable Transport Fuels Functions Bill 2022 was approved by the Government. According to the Government, the main purpose of this Bill is to strengthen the Government's ability to manage stocks in the unlikely event of a curtailment of oil supplies. The Bill provides for more clarity around the powers of the Minister and how quickly they can be deployed to control the supply and distribution of fuel in an emergency. The Bill also provides for putting all aspects of oil emergency planning on a statutory footing and establishing a register of oil suppliers to ensure fast communication to retailers.

Gas

Nature of the market

The Irish natural gas market was fully liberalised in July 2007 pursuant to amendments to the Gas Act 1976, as amended ("Gas Act") by the Energy (Miscellaneous Provisions) Act 2007. In 2014, the gas market was fully price-deregulated and there are currently a number of licenced suppliers in the market. In 2021, natural gas accounted for about 41% of the total primary energy supply and was the second-largest source of energy in Ireland (oil being the largest source). Ireland sources about one quarter of its gas from the Corrib gas field, off the coast of County Mayo, Ireland, with the balance imported via the UK from various sources, mainly indigenous supplies and via pipeline from Norway.

Key market players

Ervia, established in 2014, is a state-owned multi-utility company responsible for delivery of gas and water infrastructure in Ireland. The Department of Planning, Housing and Local Government is responsible for corporate governance of Ervia, which includes Gas Networks Ireland ("GNI") (previously Gaslink) as a subsidiary. GNI was created in 2014 as a stand-alone gas network business within Ervia. GNI holds two licences from the CRU for operation of Ireland's gas transmission and distribution systems, and builds and develops Ireland's infrastructure, operating over 13,954 kilometres of gas pipelines.

The state-owned multi-utility company Ervia (previously Bord Gáis Eireann) owns the entire transportation (transmission and distribution) system. GNI was established as the ISO for the Ervia transportation system (distribution and transmission system) under the European Communities (Internal Market in Natural Gas) (BGE) Regulations 2005 (as amended).

The main domestic gas supplier is Bord Gáis Energy Limited (now owned by the Centrica plc group). Flogas Natural Gas Limited supplies gas to domestic customers in a number of newly connected towns. Other domestic suppliers include Energia (a subsidiary of the Viridian Group, which is the largest independent electricity supplier in Ireland), SSE (Airtricity) and Electric Ireland. Non-domestic suppliers include Energia, SSE (Airtricity), Electric Ireland, Vayu, Gazprom and Phoenix Energy. The single largest consumer of gas in Ireland is the power generation sector. Most power generation companies have licences to ship their own gas.

Kinsale Head gas field, off the coast of County Cork in the south of Ireland, is Ireland's first domestic gas production field. Production began in 1979, however, the field began to decline in the late 1990s. Other fields nearby helped to offset this decline, ie Ballycotton (1989), South West Kinsale (1999), which became depleted in the late 1990s, and Seven Heads (2003).

In April 2019, the Minister of State at the DECC approved the decommissioning plans for the Kinsale Head and the Seven Heads gas fields. The gas reserves came to the end of their productive lives and were fully depleted by 2020. The offshore decommissioning activities, which take about two to three years to complete, began in July 2020. The decommissioning activities include the plugging and abandoning of development wells, the removal of two platform topsides structures and the removal of a number of subsea facilities. The onshore decommissioning occurred during 2022.

The Corrib gas field, off the coast of County Mayo in the north-west of Ireland, was discovered in 1996. Production began in late 2015, and in 2017 the Corrib gas field accounted for 95% of the 3.5 billion cubic metres ("bcm") of domestic gas production. The Corrib gas field supplies about 30% of Ireland's gas needs with the balance being imported from the UK through two interconnectors via the Moffat entry point in Scotland.

The annual demand for gas in Ireland is expected to be at a maximum of 23% by 2026. Gas demand for power generation is expected to decrease from 2016 to 2026 due to increased renewable power capacity. However, up to 2026, industry and commercial sector gas demand is expected to grow by 9.8%. This expected increase is due to the potential attractiveness of Ireland as a destination for data centres.

Approximately 125,000 new residential customers are expected to be connected by GNI to the gas distribution network by the end of 2027, which implies a switch from oil to gas for heating. This projected increase in gas usage is however counterbalanced by improved energy efficiency.

In 2021, the largest market share of the domestic gas market was held by Electric Ireland with 43%, followed by Bord Gáis Energy with 21%, Energia with 12%, SSE Airtricity with 10%, PrePayPower with 7%, Flogas and Panda Power, each with 2% and Pinergy and Iberdrola, each with 1%.

Regulatory authorities

The CRU is the regulatory authority for the downstream elements of the gas sector. The Petroleum Affairs Division of the DECC is the authority responsible for the upstream elements. The Minister maintains overall policy responsibility for the gas sector.

Legal framework

The Gas Act is the main piece of legislation for the gas sector together with the Gas (Interim) (Regulation) Act of 2002 ("Gas Regulation Act"). Bord Gáis Eireann (now Ervia) was established under the Gas Act.

The Petroleum and Other Minerals Development Act 1960 (as amended) ("Petroleum Act") governs gas exploration and production of natural gas. The Petroleum Act is given effect through the Licensing Terms for Offshore Oil and Gas Exploration, Development and Production 2007. Those wishing to explore for gas must obtain a licence under the regime set out in the Petroleum Act. Developers wishing to participate in production operations must obtain a petroleum lease under section 13 of the Petroleum Act.

A system of licensing for the supply, storage and shipping of gas is provided for under the Gas (Interim) (Regulation) Act 2002 ("Gas Regulation Act") at section 16; licences for supply and shipping are issued by the CRU. The Gas Regulation Act also sets out a system of licensing for the operation or ownership of a distribution or transmission pipeline, related powers of the CRU regarding provision of information, and an appeal process in connection with conditions of third party access.

Developments in the gas sector have seen the implementation of binding EU gas codes, which are sets of rights and obligations that apply to parties operating in the European gas markets. To date, gas network codes have been formally adopted for gas for interoperability, balancing, capacity allocation mechanism, congestion management procedures and transmission tariff structures.

Implementation of EU gas directives

The Third Gas Directive, except for Article 3 and Article 41(1) (o) and (q) and Annex I, have been transposed into national law through the European Communities (Internal Market in Natural Gas and Electricity) Regulations 2011 (S.I. 630 of 2011).

B.2 Third party access regime to gas transportation networks

The Gas Act[10] sets out a statutory framework for third party access to the gas transportation system. Third party access is regulated and based on published tariffs, which are approved in advance by the CRU, along with the methodologies for their calculation.

Operators licensed under section 16 of the Gas Regulation Act that receive an application for third party access for a transmission or distribution pipeline must offer to enter into an agreement for such access, which is subject to the applicant meeting the criteria set out in the Gas Regulation Act. If the applicant requires a connection, the offer of access must include terms and charges for that connection. Pipeline operators can refuse requests for access on the basis of a lack of capacity in the pipeline.

The Ervia transportation system is governed by the code of operations ("Code"), which is based on an entry/exit capacity regime. The Code is set out in sections that outline general principles, regulatory compliance, capacity arrangements (both entry and exit), nomination and allocation arrangements, balancing, shipper registration, gas specification and congestion management, among other things.

Under the Code, shippers can purchase entry capacity, back-up capacity, exit capacity from the transmission system, and supply point capacity for exit from the distribution system. Shippers can also reserve primary capacity directly from the transporter. Short-term capacity products have been available under the Code since 2007. To accede to the Code, shippers must enter into a binding framework agreement; shippers that are active at entry points must also accede to the relevant entry point agreements at that point. The latest version of the code (version 5.03) was published in January 2020.[11]

B.3 LNG terminals and gas storage facilities

To date, no liquefied natural gas ("LNG") terminals have been constructed in Ireland. There is an operational gas storage facility in Kinsale, County Cork.

A project to develop an LNG import terminal alongside a deep water site on the Shannon River estuary in the west of Ireland ("Shannon LNG") is seeking planning permission for the project. The Shannon LNG also plans to build an associated 500MW combined heat and power ("CHP") plant.

In January 2019, the Friends of the Irish Environment ("FiE") brought a case against the developers of the €500 million LNG processing terminal to the High Court. In February 2019, the High Court ordered the developers not to begin construction of the LNG terminal and referred the case to the Court of Justice of the European Union ("CJEU") to rule on issues relating to the European Habitats Directive. One of the main issues in the case was the question of to what extent the Directive should have applied when An Bord Pleanála extended planning permission to Shannon LNG. On 9 September 2020, the CJEU delivered judgment finding that where an original consent had expired, that the extension did amount to an agreement, which required, among other things, screening to be conducted by the planning authority for appropriate assessment under the Habitats Directive, and depending on the result of the screening, may necessitate further steps to be taken[12].

As of April 2023, Shannon LNG has yet to get planning permission for the project.

B.4 Tariff regulation

The Gas Regulation Act governs gas tariffs and provides that the holder of a licence to own and operate the gas transmission or distribution system must adopt and publish tariffs. These tariffs must be approved by the CRU under a methodology compatible with Article 41(6) of the Third Gas Directive. Such methodology must be non-discriminatory and cost reflective. The current price control period for GNI operates from October 2017 to September 2027.[13]

B.5 Market entry

Parties wishing to explore and produce gas must be licensed under the Minerals Development Act 1960. Shippers of gas must be licensed, accede to the Code and must also enter into a number of agreements.

In February 2021, the Minister introduced new legislation to end the issuance of new licences for the extraction and exploration of gas and oil. Existing licences for exploration and extractions will remain in place. The legislation is included in the Climate Action and Low Carbon Development (Amendment) Bill 2021. The legislation also involves amendments to the Petroleum and Other Minerals Development Act 1960, which is the legislation governing the issuing of petroleum authorisations in the Irish offshore (see section E).

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The PSO is collected from electricity. For more see section A.6.

Smart metering

Smart meters are optional. For more see section A.6.

B.7 Cross-border interconnectors

GNI operates both the transmission and distribution gas networks in Ireland, which deliver gas to over 680,000 customers. Gas is transported via the transmission network entry points at Moffat in Scotland, Inch in County Cork, Ireland, and Bellanaboy in County Mayo, Ireland, to the distribution networks and connected loads. Gas is also supplied to Northern Ireland and the Isle of Man via the GNI transmission network.

The GNI network is connected to the national grid gas network in the UK at the Moffat entry point. Moffat allows gas to be imported to Ireland via two subsea interconnectors, which currently do not allow Ireland to export gas as they are unidirectional. The Inch entry point connects the Kinsale and Seven Heads gas fields offshore County Cork to the GNI network onshore, and Bellanaboy connects the offshore County Mayo Corrib gas field to the GNI network.

A gas pipeline runs from Gormanston, in County Meath, to Ballyclare, County Antrim ("South-North pipeline"), where it links into the North-West pipeline in Northern Ireland. The South-North pipeline created an all-island gas transmission network, connecting the grids north and south for the first time.

C. Energy trading

C.1 Electricity trading

Until October 2018, the SEM had been organised around one pool and timeframe; however, following the introduction of the new iSEM, which went live on 1 October 2018, the market is now organised around different markets with different timeframes. The key benefits of the iSEM include creating a more competitive market, making efficient use of existing infrastructure, maximising use of renewables, providing better investment signals for investors, promoting security of supply and providing a larger more dynamic market.

The new trading opportunities present generators and suppliers with multiple opportunities to trade. The iSEM offers flexibility in who can take part and the different ways in which the participants can trade over different time periods. The different trading markets include the forwards market, financial trading rights, day-ahead markets and intraday markets. The SEM allows participants to spread the risk of their financial commitments as their contractual investments can be offset or spread, ie hedged (which includes contracts for difference (CfDs)). The trading before (ie ex-ante market) allows participants to send in bids before the delivery of power. Under the day-ahead market early bids can be made from 19 days out up to a day before trading. Under the intraday market, participants can change their bids much closer to the time on which the power is delivered; the market runs right up to one hour before trading.

The market price is set through market forces, ie suppliers are price makers that set limits on what they are willing to pay in each market, and the price settles where the suppliers' limits cross with what generators accept.

Under the new iSEM, suppliers and generators must match their actual generation and usage with what is traded. If generation or usage figures differ, the suppliers or generators will be liable for the difference in costs in the balancing market. Capacity payments are paid to generators only when their output is required to meet demand and only if they can meet such demand. Interconnection capacity on trading across interconnectors with Great Britain is allocated based on prices of electricity flowing from the cheapest to the most expensive market.

Generators with capacity of more than 10MW must participate as a generator in the SEM, however, generators with capacity of less than 10MW may participate in the SEM but are not required to do so.

C.2 Gas trading

The Irish Balancing Point ("IBP") operates under the entry/exit capacity regime. The IBP is a notional point on GNI's network gas system where shippers can trade entry-paid gas. GNI has prior to this procured balancing gas via rigid bi-lateral contracts with limited volume and timing constraints. GNI uses Trayport Vision provided by Energy Brokers Ireland to facilitate the IPB market, which was launched in 2016, and uses a standard IBP trading contract based on the national balancing point terms.

D. Nuclear energy

Ireland has chosen not to develop a nuclear power industry for the generation of electricity. Moreover, the generation of electricity in Ireland from nuclear energy is prohibited by law. Under section 18(1) of the Electricity Act, the Minister must specify the criteria according to which an application to the CRU for an authorisation to construct a generation station is determined. Under section 18(6) of the Electricity Act, such an order is prohibited from providing for the use of nuclear fission in the generation of electricity.

Section 37K of the Planning and Development (Strategic Infrastructure) Act 2006 provides that no development in respect of nuclear installations is authorised.

E. Upstream

To date, there have been no commercial discoveries of oil in Ireland. There have been four commercial natural gas discoveries since exploration began offshore Ireland in the early 1970s, ie Kinsale Head, Ballycotton and Seven Heads gas fields off the south coast, and the Corrib gas field off the north-west coast. For more on gas see section B.1.

By operation of law, the Irish State does not hold ownership interests in any hydrocarbon projects. Operators must obtain the approval of the Minister, however, there are no express qualifications on who can be an operator.

Petroleum exploration and development

The Petroleum Act, ie the Petroleum and Other Minerals Development Act 1960 (as amended) governs oil exploration and production. The Petroleum Act is given effect through the Licensing Terms for Offshore Oil and Gas Exploration, Development and Production 2007. Those wishing to explore for oil must obtain a licence under the regime set out in the Petroleum Act.

Climate action and low carbon development

The Climate Action and Low Carbon Development (Amendment) Bill 2021 proposes amendments to Petroleum Act which aim to statutorily prohibit the granting of new petroleum prospecting licences, licensing options, exploration licences, lease undertakings and petroleum leases in line with commitments under the Programme for Government.

Offshore exploration

The Petroleum Affairs Division of the DECC is responsible for licensing and regulating oil and gas exploration and production activities, both offshore and onshore Ireland. To explore the Irish offshore, or onshore, for oil and gas, companies must be issued with an authorisation to do so by the Minister, which the Minister issues under the Petroleum Act. Potential exploration and production activities may also require a foreshore licence under the Foreshore Act 1933 (as amended), the provisions of the Planning and Development Acts 2000 to 2013, and the Continental Shelf Act 1968 (as amended). Applications for foreshore licences must be made to the Department of Housing, Planning and Local Government.

The various authorisations that can be applied for include:

- Petroleum prospecting licence (issued under section 9(1) of the Petroleum Act), which is a non-exclusive licence that gives the holder the right to search for petroleum in any part of the Irish offshore that is not the subject of a petroleum exploration licence, reserved area licence or petroleum lease granted to another party.
- Licensing option (issued under section 7(1) of the Petroleum Act), which is a non-exclusive licence that gives the holder the first right, exercisable at any time during the period of the option, to an exploration licence over all or part of the area covered by the option.
- Exploration licence (issued under section 8(1) of the Petroleum Act), of which there are three categories, ie standard exploration licence for water depths up to 200 metres, deepwater exploration licence for water depths exceeding 200 metres, and frontier exploration licence for areas so specified by the Minister.
- Lease undertaking (issued under section 10(1) of the Petroleum Act), which is an undertaking by the Minister to grant a petroleum lease at a stated future date subject to certain conditions. This is issued in circumstances where a discovery is made and the licensee is not in a position to declare the discovery commercial but expects to do so in the foreseeable future.
- Petroleum lease (issued under section 13(1) of the Petroleum Act), which is issued when a commercial discovery is

established and the holder of the authorisation must notify the Minister of such discovery and apply for a petroleum lease with a view to its development.

- Reserved area licence (issued under section 19(1) of the Petroleum Act), which a holder of a petroleum lease can apply for in respect of an area adjacent to or surrounding the leased area that is subject only to a petroleum prospecting licence.

When considering applications for authorisations, the Minister takes into account the proposed work programme, technical competences and offshore experience, financial resources, and, if relevant, the applicant's performance under other authorisations, among other things.

The relevant authorisations specify minimum work obligations and authorisations may be revoked in the event of substantial breaches or non-observance of requirements set out in law or by direction of the Minister. Other situations where relevant authorisations may be revoked include failing to pay monies due within 30 days, withholding significant information from the Minister, giving false information to the Minister, and on appointment of a receiver or liquidator. The Minister must be notified of any transaction that results in either a major change in the shareholdings of the authorisation holder or of its parent company, or a major change in the control of the authorisation holder or its parent company.

There are no Government consents required under statute to grant security over a petroleum interest, however, the terms of the petroleum lease may contain restrictions. A lease may be assigned with, typically, the Minister's prior written consent, and there are usually no express restrictions on change of control. However, under the Licensing Terms for Offshore Oil and Gas Exploration, Development and Production (2007) ("Licensing Terms"), the Minister may impose conditions on the new licensee at the consent stage. The Licensing Terms are the terms and conditions under which petroleum authorisations are granted. There is no third party access regime in relation to any upstream exploration, production or transport facilities.

The Minister introduced the petroleum production tax ("PPT")[14], which replaced the profit resource rent tax for new authorisations. The PPT applies at variable rates of 0% to 40% linked to the profitability of any discoveries and is permitted as a deduction from corporation tax. There is a minimum annual PPT payment of 5% of the gross revenues of a field once production begins. The revised tax terms have been implemented by way of section 20 of the Finance Act 2015, which was enacted on 21 December 2015, and the revised terms apply for authorisations first awarded from 18 June 2014.

The Petroleum (Exploration and Extraction) Safety Act 2010 ("Petroleum Safety Act 2010") amended the Electricity Act to give the CRU responsibility for regulating the safety of petroleum undertakings engaging in certain petroleum activities. Under the Petroleum Safety Act 2010, the CRU must establish and implement a risk-based petroleum safety framework ("Framework"). The High Level Design of the Petroleum Safety Framework provides an overview of this Framework, which is currently in operation. The Framework includes a number of other documents, including the Safety Case Guidelines, the ALARP Guidance, the Compliance Assurance System, the Petroleum Safety (Petroleum Incident) Regulations 2014 (S.I. 4 of 2014) and the Petroleum Safety (Designation of Certain Classes of Petroleum Activity) Regulations 2013 (S.I. 89 of 2013) ("Petroleum Safety Regulations 2013").

The Petroleum Safety (Petroleum Incident) Regulations 2016 (S.I. 166 of 2016) ("Petroleum Safety Regulations 2016") enable Part IIA of the Electricity Act to have full effect and prescribe the class of event for the purposes of defining a petroleum incident, among other things.

The Offshore Safety Directive has been transposed into Irish Law by the Petroleum (Exploration and Extraction) Safety Act 2015 ("Petroleum Safety Act 2015"). Under the Petroleum Safety Act 2015, the CRU is identified as the competent body for offshore safety, the risk and potential consequences of major accidents (including major environmental incidents) is covered, and certain responsibilities for the safety of petroleum activities carried on offshore are transferred from petroleum undertakings to operators and owners of non-production installations.

F. Renewable energy

F.1 Renewable energy

In 2020, Ireland generated 12.6TWh of electricity from RES, which accounted for 36.4% of the total electricity generated.

A number of Government measures encourage investment in renewable energy include:

- A biofuels obligation scheme (see section F.3) and registration of hybrid EVs and flexible fuel vehicles.
- A renewable electricity support scheme ("RESS"), which broadly expands the renewable technology mix in Ireland and sees a series of renewable technology competitive auctions run throughout its lifetime. The RESS encourages community-based ownership and participation in renewable energy installations. There have been two RESS auctions to date.
- A programme supporting solar PV installation that focuses on technology, battery storage and the impact of microgeneration on consumers' energy behaviour.

F.2 Renewable pre-qualifications

RESS is available under two categories of preference, ie the all projects category and the community preference category. Applicants under the community preference category must be 100% community-owned, with a minimum offer quantity of 0.5MW and a maximum offer quantity of 5MW.

Community zero-bond projects are excluded from the all projects category. However, community-led projects are still eligible if the project can offer a bid bond and performance security. The minimum offer quantity is 0.5MW, with the maximum offer the MW equivalent of 600GWh/year. Solar projects and hybrid solar and storage projects will have an evaluation correction factor of 0.90 under the all projects category. Other relevant eligible technologies will have an evaluation correction factor of 1.

Applicants cannot aggregate smaller projects to achieve the minimum offer quantity for a preference category. However, they may be able to do so if an applicant organises one single project behind a single meter and a single applicant entity that meets all of the qualification requirements under the terms and conditions.[15]

F.3 Biofuel

About 240 million litres of biofuel are placed on the Irish market annually. Under the Renewable Energy Directive, all EU Member States had to achieve a minimum target of 10% renewable energy in the transport sector by 2020. In an effort to achieve this target, Ireland introduced a biofuels obligation to be imposed on suppliers of petrol and auto-diesel, ie the Renewable Transport Fuel Obligation ("RTFO"), previously the Biofuels Obligation Scheme ("BOS"). The BOS, now RTFO, was introduced through the Energy (Biofuel Obligation and Miscellaneous Provisions) Act 2010, which came into force on 1 July 2010, and is administered by the National Oil Reserves Agency ("NORA"). The Act is a primary policy measure introduced to increase the proportion of renewable energy in the transport sector and its introduction has also contributed significantly to reducing GHG emissions.

Under the RTFO, road transport fuel suppliers must include a certain proportion of environmentally sustainable biofuels in their general fuel mix and each supplier must fulfil their requirements by having the required number of biofuel certificates. Additionally, under the RTFO, suppliers of mineral oil in Ireland must ensure that 16.985% (of volume) of the motor fuel they place on the Irish market is renewable, eg bioethanol or biodiesel. This means that about 17% of motor fuels, ie petrol and diesel, on the Irish market are to be produced from renewable sources. Public consultations took place in 2022 for changes proposed for 2023. The public consultation closed on 7 December 2022; no result was available as at date of publication. Subsequently, further consultations are to take place every two years in advance of any proposed changes to the RTFO.

Under the National Oil Reserves Agency Act 2007 ("NORA Act"), biofuel certificates obtained in one year can be carried over and counted up to a maximum of 25% of a party's biofuel obligation in either of the following two years.

This flexibility is important as it allows the transport industry to respond to market changes, however, it also runs the risk that the overall contribution to national targets in a particular year may be considerably less than the obligation rate. It was therefore proposed to reduce the carryover of biofuel certified from 25% to 15% from 1 January 2020. It its consultation report of 2022, the Department of Transport stated that it did not propose to make any changes in 2023 in relation to the 15% carryover limit. The renewable transport fuel obligation rate trajectory is expected to be sufficiently high by mid-2020s to meet the Fuel Quality Directive[16] annual target of 6% GHG reduction.

The Biofuels Directive was transposed into Irish law by the European Communities Act, 1972 (Environmental Specifications for Petrol, Diesel, Fuels and Gas Oils for use by non-road mobile machinery, including inland waterway vessels, agricultural and forestry tractors, and recreational craft) Regulations 2011 (S.I. 155 of 2011).

The Energy Act 2016 provides for increased flexibility concerning end of period reconciliation dates and also allows NORA to determine the deadline dates for quarterly applications for certificates under the BOS.

G. Climate change and sustainability

G.1 Climate change initiatives

Ireland introduced a carbon tax on the supply of fossil fuels in 2010. The carbon tax was implemented by way of a new mineral oil tax carbon charge (which is included in the existing mineral oil tax) and a new natural gas carbon tax. Carbon tax is charged at a rate of €20 per tonne of CO_2 emissions.

A solid fuel carbon tax ("SFCT") was introduced in May 2013. SFCT is an excise duty that applies to solid fuel (coal and peat) supplied in Ireland.

Effective as of 1 May 2022[17], coal is taxed at an SFCT rate of €107.98 per tonne and peat briquettes at a rate of €75/17 per tonne. In respect of peat, Bord na Móna suspended its peat harvesting operations in Ireland in 2018 and, following a High Court judgment in 2019, formally ended all peat harvesting on its lands in 2019. Peat briquettes will no longer be made in Ireland after 2024.

The Taxes Consolidation Act 1997 (as amended) sets out a securitisation regime, which extends carbon offsets that include both GHG allowances under an approved scheme by a Governmental institution and GHG allowances produced under a voluntary scheme sponsored by a state institution or commercial enterprise that is subject to independent monitoring and reporting. The regime also extends to include forest carbon offsets.

The Government has introduced various incentives to expand the use of alternative fuels and technologies, which include:

- an excise rate for natural gas and biogas used in transport at the EU minimum rate of €2.60 per gigajoule;
- a new accelerated capital allowance programme for gas-fired commercial vehicles;
- grants of up to €5,000 to incentivise consumers to purchase a battery EV or a plug-in hybrid EV; and
- accelerated capital allowance for energy efficient equipment purchases by companies paying corporation tax.

The Government is also investing in maintaining and expanding public transport infrastructure, and is allocating €2.6 billion for investments and renewal of assets and €1 billion for targeting congestion. Access to alternatives to private cars is also improving through initiatives such as the Smarter Travel Programmes, to which the Government has allocated €100 million.

National mitigation plan

The DECC (then the DCCAE) published the first National Mitigation Plan towards decarbonisation, focusing on electricity generation and achieving a low carbon energy sector by 2050, taking into consideration that the EU has set out ambitions to reduce GHG emissions by 80% to 95% by 2050, compared with 1990 levels.[18]

Ireland's first National Mitigation Plan includes the built environment, focusing on improving energy efficiency and reducing GHG emissions; transport, focusing on containing the level of emissions associated with the transport sector and identifying a range of potential additional measures that can help to intensify mitigation efforts within the sector; and the agriculture, forest and land use sectors, focusing on an approach to carbon neutrality that does not compromise capacity for sustainable food production.

The mitigation measures proposed in the plan include:

- a new public service obligation funded renewable electricity support scheme;
- further electricity interconnection;
- keeping the rate at which carbon tax is set under review;
- no longer supporting electricity generated from peat under the public service obligation; and
- support for ocean research, development and demonstration.

All of Government plan on climate disruption

The Government gave the Minister a mandate to prepare an All of Government Plan on Climate Disruption to bring about a change in Ireland's climate ambition up to 2030 and beyond. The plan sets out the actions that must be taken to make Ireland a leader in responding to climate change. The plan builds on existing policy and is be organised under six themes that focus on sectors that contribute to GHG emissions. These themes include:

- framework conditions;
- adopting known technologies;
- driving change in business models;
- addressing market failure;
- public sector leading by example; and
- promoting behavioural change (ie harnessing the citizen and community effort).

Climate action plan

The Government published its 2023 climate action plan, ie Climate Action Plan 2023 (CAP 2023) in December 2022. CAP 2023 is the second annual update to Ireland's initial Climate Action Plan 2019 and, building on the 2019 plan, sets out a course of action to address climate disruption in Ireland with the aim of achieving a 50% reduction in overall GHGs by 2030 and net zero emissions by no later than 2050. These targets are set out in legislation under the Climate Action and Low Carbon Development (Amendment) Act 2021.[19]

The CAP 2023 sets out, among other things, the current state of play in 'six vital high impact sectors' in Ireland, and the measures to be implemented to achieve target reductions in emissions in each of these key sectors by 2030. The six vital high impact sectors set out are: powering renewables, commercial/public and residential buildings, transport, agriculture, enterprise and services, and land use. The target reduction emissions by 2030 are to be reduced respectively by: 75%, 45%-45%, 50%, 25%, 35%. The plan notes that for land use the exact reduction target is yet to be determined.

The plan outlines how these target reductions are to be achieved with Government driving policies to reduce carbon emissions and with initiatives such as supporting farmers to continue to produce food while seeking to diversify income through eg energy generation and forestry.

The CAP 2023 also sets a target of up to 80% renewable electricity by 2030, an increase of 10% of the target set under the Programme for Government.[20]

Carbon budgets

Ireland has introduced economy-wide carbon budgets, which came into effect on 6 April 2022, and sectoral emissions ceilings, which were approved on 28 July 2022.

A carbon budget represents the total amount of emissions (CO_2/tonnes equivalent) that a county or region may emit during a specific time period. A sector ceiling represents the maximum amount of GHG emissions permitted within different sectors of the economy during a carbon budget period. The sectors include: electricity, transport, built environment - residential, built environment - commercial, industry, agriculture, land use, land-use change and forestry ("LULUCF"), and other sectors (eg gases, waste and petroleum refining).

CAP 2023 implements a carbon budget programme that comprises three five-year budget periods (2021-2025; 2026-2030; and 2031-2035 (provisional)) with sector-specific emissions ceilings operating within the parameters of the budgets. Other actions include measures such as an enhanced new forestry programme to include a range of forest creation measures and planting of small native areas, and also encouraging the use of renewables in the petroleum refining process.

Transition funding

Ireland has secured €84.5 million under the EU Just Transition Fund ("EU JTF"). The EU JTF was established as part of the EU Green Deal to support the most affected regions in the EU member states to meet the changes associated with achieving the EU's climate targets for 2030 and climate neutrality by 2050.

The funding secured from the EU JTF will be matched by exchequer resources (up to €169 million). The support will contribute to economic diversification in the midlands region of Ireland through enhancing the regional economy by, among other things, generating employment for former peat communities, supporting rehabilitation and restoration of degraded peatlands, and providing smart and sustainable mobility options to former peat communities.

Energy efficiency

Suppliers face increased obligations with regard to energy efficiency pursuant to the Energy (Miscellaneous Provisions) Act 2012 ("Energy (MP) Act 2012"), which include ensuring the offer and promotion to final customers of competitively priced energy services, ensuring the availability and promotion to final customers of competitively priced energy audits. Suppliers must also ensure the availability and promotion to final customers of competitively priced energy efficiency improvement measures or contributions to the fund, ie the Ireland energy efficiency fund ("IEEF") established under the Energy (MP) Act 2012, at a rate specified by the Minister.

A €75 million IEEF was established to deliver energy efficiency projects across the Irish public and private sector. The IEEF finances energy efficiency projects and also seeks to partner with clients to deliver the projects. The various projects include building retrofit (including lighting, heating, ventilating, and air-conditioning, waste heat recovery, process optimisation) and generation, which includes CHP, boilers and heat pumps. The projects are focused on key sectoral areas including agri-food, hospitality, healthcare, retail, education, industrial processes and facilities, and data centres.[21]

The Energy Efficiency Directive is transposed (certain provisions) into Irish law through the EU (Energy Efficiency) Regulations 2014 ("Energy Efficiency Regulations") and the EU (Energy Efficiency Obligation Scheme) Regulations 2014.

The Energy Efficiency Regulations, among other things, impose obligations on public bodies relating to the efficient use of energy, require the publication of minimum criteria for energy audits and the establishment of a national registration scheme for the registration of energy auditors, and set out other requirements and measures relating to energy efficiency.

Ireland's National Energy and Climate Plan ("NECP") was published in 2020 and sets out Ireland's ambition for energy efficiency savings in the period to 2030, which projects 62.2TWh of primary energy savings in 2030. The policies, measures and programmes that Ireland is already undertaking, developing and considering to achieve energy efficiency and climate objectives are set out in, among others, the National Energy Efficiency Action Plan (2014), the National Mitigation Plan (2017), Long Term Renovation Strategy (2017) and National Development Plan (2018). These plans set out policies and measure target savings in all sectors, including the introduction and use of measures such as carbon tax.

G.2 Emission trading

The New EU ETS Directive has been implemented in Ireland by the European Communities (Greenhouse Gas Emissions Trading) Regulations 2012, which consolidated Ireland's regime and revoked a number of previous regulations implementing the EU ETS in Ireland.

The EU ETS is being implemented in distinct phases or trading periods, ie Phase I and II for 2005 to 2012, Phase III for 2013 to 2020, and Phase IV for 2021 to 2030.

In Phase III, auctioning progressively replaced free allocation as the main method for allocating allowances to all EU ETS sectors. All EU Member States appoint an auctioneer that offers the allowances to be auctioned to the auction platform on behalf of the Member State. The Environmental Protection Agency ("EPA") was appointed as auctioneer for Ireland under the European Communities (Greenhouse Gas Emissions Trading) Regulations 2012 (S.I. 490 of 2012).

The ETS in Ireland is run on a day-to-day basis by the EPA. The EPA compiles Ireland's annual GHG emission inventories and projections, which allow the Government to assess progress in meeting targets, among other things. The EPA inventory compiles historical GHG emissions, ie a summary of past emissions, from sources such as transport, power generation, industry and agriculture, from 1990 to the most recent year for which data is available. The EPA GHG emissions' projection is an estimate of what emission levels may be in the future based on key assumptions such as economic growth, fuel price and Government policy.

The legislative framework of the EU ETS was revised in 2018 to enable it to achieve the EU's 2030 emission reduction targets in line with the 2030 climate and energy policy framework and as part of the EU's contribution to the Paris Agreement.

The Irish Carbon Trading Platform (ie Cosain) is Ireland's own voluntary carbon exchange platform. Cosain allows installations and brokers to trade allowances online, and also facilitates the trading of carbon credits in voluntary offset markets (permitting the holder to emit one tonne of carbon dioxide).

G.3 Carbon pricing

Ireland, as a member of the EU, implements its carbon pricing through the EU ETS.

Ireland is also one of 15 EU member States that has economy-wide pricing through a combination of the ETS and a separate domestic carbon tax that is applied to sectors not included in the ETS.

Under the Finance Act 2020, natural gas carbon tax and solid fuel carbon tax increase each year over a period of 10 years to conclude at €100 in 2030 per tonne of CO_2 emitted. An increase of €7.50 per tonne of CO_2 took effect as from 1 May 2022, with the amount charged per tonne increased to €41 per tonne. Future increases will take effect as of 1 May each year up to and including 2030.[22]

G.4 Capacity markets

Ireland has an all-island wholesale electricity capacity market, ie the SEM capacity market, which is designed to ensure that there is sufficient electricity power in both jurisdictions of Ireland and Northern Ireland up to an accepted loss of load expectation (LOLE) standard of risk. Additional capacity is needed for operational reserves and to facilitate transmission outages planning. The SEM is regulated by the Single Electricity Market Committee (SEM Committee) which comprises three representatives from each of the Irish regulator, ie the CRU, and the Northern Ireland regulator, ie the Utility Regulator, and two independent members. EirGrid and SONI operate the integrated SEM (iSEM) under the joint venture SEMO.

The capacity market auction takes place every year for capacity in a future year (year(s) ahead), either for the year ahead (T-1 auctions), two years ahead (T-2 auctions) or four years ahead (T-4 auctions). The amount of generation required in the SEM capacity market is set by the capacity requirement, which is calculated by EirGrid and SONI in accordance with the methodology as set out within the Capacity Requirement and De-Rating Factor Methodology Detailed Design Decision Paper[8] and subsequently approved by the relevant regulatory authorities, ie the CRU in Ireland and the Utility Regulator in Northern Ireland.

Under the SEM, only generating units that are successful in the capacity auctions will receive capacity payments. The aim of the auction is to ensure that consumers do not pay for more capacity than is needed. The generators that are successful at the auctions will receive regular payments for which they must deliver on their capacity market obligations.

For the SEM 2023/2024 T-4 capacity auction, 124 capacity market units ("CMU") were submitted for which a total of 8,413.442MW of de-rated capacity was offered into the auction. A CMU is a unit of electricity generation capacity or electricity demand reduction that can then be put forward in a future capacity market auction.

The T-4 auction secured a total of 7,322.471MW for the island.

H. Energy transition

H.1 Overview

The energy transition is taking effect in Ireland in a variety of ways. The country has set ambitious targets for reducing GHG emissions and increasing the share of renewable energy, and there are a range of policy and regulatory initiatives in place to support these goals.

In July 2022, the Government reached agreement on sectoral emissions ceilings which set maximum limits on GHG emissions for each sector of the Irish economy to the end of the decade. The sectoral emissions ceilings have been set for the electricity, transport, buildings, industry and agriculture sectors to reach an overall goal of 51% reduction in GHG emissions by 2030. The new agreement commits additional resources for offshore wind (moving from a target of 5GW to 7GW), green hydrogen (an additional 2GW), agro-forestry and anaerobic digestion (up to 5.7TWh of biomethane) and solar (more than doubling the target to 5.5GW). The additional commitments are aimed at further accelerating the reduction of overall economy wide emissions.

Offshore wind

In March 2023, the Irish government formalised plans to accelerate the delivery of 5GW offshore wind capacity by 2030. The Policy Statement on the Framework for Phase Two Offshore Wind outlines how the first auction for offshore wind under the Renewable Electricity Support Scheme (ORESS 2) is expected to launch by the end 2023, following a public consultation on draft auction terms and conditions in mid-2023; the first auction was launched by EirGrid in December 2022.

Phase one output will be subsidised through ORESS 1, which will have a maximum offer price of €150/MWh. However, with a combined capacity of phase one projects totalling around 4.4GW, coupled with prospects that some phase one projects may fail to secure a route to market or development consent, additional offshore projects are expected to be needed to meet 5GW by 2030. This transition from phase one to the longer term enduring offshore regime is known as phase two.

The first auction relates to the delivery of offshore wind capacity on the south coast of Ireland, geographically aligned with available onshore grid capacity. This auction, and all subsequent phase two auctions, will result in the development of offshore wind capacity within 'Offshore Renewable Energy (ORE) Designated Areas'. These areas, which will be designated according to legislative provisions for Designated Maritime Area Plans (DMAPs) in the Maritime Area Planning (MAP) Act, will guide investment and decision-making and will complement the network of Marine Protected Areas.

Beyond phase two and the 5GW objective, Government has further committed to introducing a new phase, ie phase three, which targets an initial 2GW of floating offshore wind capacity off Ireland's South and West coasts. These projects are expected to be in development by 2030 and may include projects available for green hydrogen production and non-grid uses.

Biomethane

Ervia and GNI have jointly developed a long-term vision to outline how they could play a part in decarbonising Ireland and in particular the electricity, heating and transport sectors. This vision involves using natural gas as a bridging fuel out to 2030 and then using decarbonised gas as a destination fuel out to and beyond 2050.

GNI facilitate the injection of renewable gas onto the Irish Gas Network via a direct connection with a pipeline connecting a biomethane plant to the network or via transporting the biomethane to a central grid injection facility where the biomethane is injected into the gas network.

Solar

In January 2023, the solar independent power producer ("IPP") Power Capital Renewable Energy announced the closing of a €240 million construction equity facility. The facility will support the IPP's plans for 1.2GW of solar power projects to be operational by 2025. This support is expected to enable solar electricity to replace fossil fuel usage to power Ireland on sunny days and contribute to Ireland's target of up to 5GW of solar energy by 2025.

H.2 Renewable fuels

Hydrogen

One of the key priorities of the National Energy Security Framework is to set out a hydrogen strategy for Ireland to outline the road towards the production of green hydrogen and its use in the energy mix. The potential for green hydrogen to support decarbonisation across many sectors including electricity generation and high-temperature heat for industry was initially set out in the Climate Action Plan 2021.

In July 2022, the Government opened a public consultation on developing a hydrogen strategy for Ireland; the consultation closed on 2 September 2022. The consultation considered various aspects of hydrogen including research and development, demand for hydrogen in the heat, transport and electricity sectors, the supply, transportation and storage of hydrogen, export opportunities, and safety and regulation.

The hydrogen strategy is expected to provide a roadmap for the deployment of hydrogen in Ireland over the coming years and is expected to include targets for the deployment of hydrogen in key sectors such as transport, heating, and industry, as well as a range of policy measures to support research into and development of hydrogen infrastructure and the deployment of hydrogen technologies.

In respect of research and development, the SEAI is developing a number of initiatives on the role of hydrogen in decarbonisation, and considering options for green hydrogen in the heating and cooling sectors in Ireland by 2050.

Ireland's climate action plan also sets out a number of actions being undertaken including the testing and technical feasibility of safely injecting green hydrogen blends into the gas grid and assessing the potential for integration of green hydrogen into the electricity and gas networks in terms of its production, storage and use.

Various projects are being undertaken to address various challenges to the development of hydrogen, eg HyLIGHT and HySkills:

- HyLIGHT is funded by Science Foundation Ireland (SFI) and MaREI, which is a consortium of 25 industry bodies. The aim of the project is to provide knowledge, data and the tools necessary to guide decarbonisation through the implementation of cost-effective and sustainable large-scale hydrogen technologies in Ireland.
- HySkills, in which Dublin City University are involved with partner colleges across Europe, aims to develop a modular training course that includes practical elements focused on green hydrogen technical and safely skills.

Ireland is considered to be in a favourable position in the area of the green hydrogen production. with research indicating that Ireland could have optimal levelised costs of production of hydrogen of €3.5/kgH_2 in 2030, which would be 8% lower than optimal production costs in Spain and 35% lower than in Germany. Ireland is considered therefore to have the potential to produce the cheapest green hydrogen in Europe by 2030.[23]

Under its 2023 climate action plan (CAP 2023), Ireland has set a 2030 target of 2GW offshore wind set aside for the production of green hydrogen. The CAP 2023 sets out potential options for closing the unallocated emissions saving gap, which includes more reliance on emerging technologies eg hydrogen and carbon capture and storage ("CCS"). The plan highlights that further research is needed on the operational and implementation feasibility of emerging technologies and the potential of these technologies in the abatement of emissions. The plan also recognises that green hydrogen can play a significant role in the longer term in the area of increasing integration of energy supply and end-use sectors. The 2031-2035 (third carbon budget) measures under the plan include the development of policies for hydrogen, and CCS, to be undertaken following the publication of the Government's hydrogen strategy and roadmap.

Some commercial hydrogen projects are underway, eg, Indaver have received planning permission for a 10MW electrolyser to be constructed at its waste-to-energy facility in County Meath[24] and Mercury Renewables is pressing ahead with its plans to build a wind-powered green hydrogen plant in Firlough, County Mayo[25].

Ammonia

Ammonia emissions are subject to reduction commitments under the EU National Emission Reduction Commitments (NEC) Directive. Ammonia emissions decreased slightly in Ireland in 2020, however emissions continued to be non-compliant with the National Emissions Reduction Commitment (ERC), which at that time showed that ammonia emissions had been non-compliant for eight of the previous nine years.

The use of abatement technologies has led to the reduction in ammonia emissions with low emissions spreading techniques being used to apply about 36% of cattle slurries in 2020, which avoided over 5,600 tonnes of ammonia emissions; an increased uptake of 62% in protected urea fertiliser also saved over 500 tonnes of ammonia emissions, however usage was considered to remain low compared to other fertiliser types.

H.3 Carbon capture and storage

The European Communities (Geological Storage of Carbon Dioxide) Regulations 2011 transposed the CCS Directive into national law in Ireland.

For more on CCS see section H.2.

H.4 Oil and gas platform electrification

N/A. Ireland imports all the oil that it uses.

H.5 Industrial hubs

N/A. Ireland's industrial hubs are currently more focused on the areas of manufacturing and digital services.

H.6 Smart cities

One of the main initiatives in relation to smart cities is the establishment of a collaborative forum, which is supported by Maynooth University, County Kildare. The aim of the All Ireland Smart Cities Forum is for member cities to work together in relation to collaborative research and sharing of insights to advise stakeholders.

The forum is an all-island cross-border initiative between Ireland and Northern Ireland. The initiative includes local authority representation from Cork, Dublin (all four local authorities), Limerick, Galway, Waterford, Belfast, Derry and Newry with the aim of working together to explore common challenges related to implementing smart city policies and projects.

There are a variety of projects being undertaken in the smart cities arena, one of which is the 'CityTrees' project. This project consists of five striking high-tech 'CityTrees' being installed in Cork city centre as part of Cork city council's air quality strategy. The project has been put in place as a site-specific solution to the challenge of air pollution and to support public health across Cork city. The CityTrees are smart street furniture units which are four metres tall and are covered in a mixture of moss cultures that filter harmful pollutants out of the air. Each one of the CityTrees can filter the air usage equivalent of up to 7,000 people per hour and the 'trees' record the air quality around the units and have display screens for sharing information.

I. Environmental, social and governance (ESG)

Ireland is recognised internationally as one of the world's leading investment fund and management company domiciles with a growing green bond sector.

Ireland's heavily subscribed first sovereign green bond was issued for €3 billion, and the Irish Stock Exchange ("ISEQ") has a number of private green bonds listed. Investment in renewable energy in Ireland is proving very attractive and Ireland was placed 13th most attractive market internationally for renewable energy investment in 2022.

The effects of legislative developments in the EU in relation to ESG issues are yet to be experienced but it is clear that companies are increasingly prioritising ESG in recognition of these issues as key performance indicators for their companies. As of print, about 40% of top ISEQ-listed companies having dedicated ESG or sustainability committees.

Endnotes

1. The European target model includes both allocation of annual and monthly transmission rights (derivatives market) and implicit allocation in the day-ahead and intraday markets (spot market).
2. See www.connaissancedesenergies.org/sites/default/files/pdf-actualites/Energy_Policies_of_IEA_Countries_Ireland_2019_Review.pdf.
3. See www.statista.com/statistics/753319/domestic-electricity-market-share-of-customers-in-ireland.
4. See www.irishstatutebook.ie/eli/2022/act/17/enacted/en/pdf.
5. See www.gov.ie/en/press-release/e5331-new-legislation-introduced-for-the-energy-efficiency-obligation-scheme.
6. The criteria to which the CRU may consider when determining an application for such an authorisation are set out in the Electricity Regulation Act 1999 (Criteria for Determination of Authorisations) Order 1999.
7. Energy in Ireland 2020 Report SEAI, available at www.seai.ie/publications/Energy-in-Ireland-2021_Final.pdf at p.20.
8. See www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf at p.45.
9. See www.eirgridgroup.com/site-files/library/EirGrid/208281-All-Island-Generation-Capacity-Statement-LR13A.pdf at p.47.
10. Section 10A (inserted by section 14 of the Gas (Interim) (Regulation) Act 2002) of the Gas Act 1976 amended by S.I. No. 426/2004 - European Communities (Internal Market in Natural Gas) Regulations 2004. See www.irishstatutebook.ie/eli/2004/si/426/made/en/print.
11. See www.gasnetworks.ie/corporate/gas-regulation/service-for-suppliers/code-of-operations.
12. Friends of the Irish Environment v An Bord Pleanála (Shannon LNG) Case C-254/19.
13. See www.cru.ie/publications/26988.
14. Introduced in 2014.
15. See www.eirgridgroup.com/site-files/library/EirGrid/RESS-2-Qualification-Information-Pack-(R2QIP).pdf and www.seai.ie/community-energy/ress/overview.
16. Directive 98/70/EC of the European Parliament and of the Council of 13 October 1998 relating to the quality of petrol and diesel fuels and amending Council Directive 93/12/EEC.
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Energy law in Israel

Recent developments in the Israeli energy market

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Electricity sector

IPPs gaining a market foothold

During the last decade, Independent Power Producers ("IPPs") have made steady progress in expanding their market share in Israel's electricity generation sector. From roughly a 13% market share in 2014, IPPs installed capacity reached 39% in 2021 and is expected to reach 56% by 2025.[1] The share of IPPs in the generation of electricity in 2021 was higher with a share of 48%, respectively. The market expansion is fuelled by the availability of natural gas and facilitated by provisions in the Electricity Sector Law 1996 ("ES Law") and its regulations requiring Noga – Israel Independent System Operator Ltd. ("Noga" or the "System Manager"), and the Israel Electric Corporation ("IEC") (both a state-owned company) to purchase electricity generated by conventional, cogeneration and renewable energy IPPs. The IEC must also provide transmission and backup supply services to customers of licensed IPPs.

Reforming the IEC

Despite the rapid growth of the IPPs market share in the generation and supply sectors, the IEC is still the most dominant player in the electricity market, constituting a vertical monopoly throughout most of the sector's segments, ie generation, transmission, distribution and supply.

On 3 June 2018, following more than 20 years of negotiations for a large-scale structural change in the IEC, the Israeli Government ("Government") issued Government Decision no. 3859, approving the structural reform in the electricity sector and the IEC ("Reform"). This Reform is the most comprehensive ever approved in the Israeli economy and once completed, is expected to have a significant impact on the electricity sector and the general Israeli economy. The Reform is expected to be completed by 2026 and includes reforms in, among other things, the generation segment, system management, transmission inspection, transmission, distribution and supply segments, and organisational change and streamlining.

Generation segment

IEC shall reduce its activity in the generation segment through the sale of its power plants and will not be permitted to construct new generation facilities other than two new power plants, subject to certain rules:

- Sale of the IEC's power plants: As per the Reform, the IEC must sell half of its natural gas fired power plants, with a total capacity of 4,500MW, (including infrastructure and the land of each site), over a period of five years, by way of tenders to be published by IEC and in accordance with the regulations of the EA. The sale of the first power station, Alon Tavor (583MW), was completed in December 2019, followed by the sale of Ramat Hovav (1,137MW) in January 2020 and by the sale of the eastern part of Hagit power station site with a capacity of about 660MW which was concluded in December 2021. The western generation site of Hagit remained in the IEC's possession. The next power plant that is expected to be sold is Eshkol Station (the biggest of all power stations, in a capacity of 1683MW) by 2023.[2]

  Once the Reform is fully implemented, the IEC's market share of installed capacity in the generation segment is expected to decrease from about 80% in 2017 to about 44% in 2025, and to about 33% several years thereafter.
- Establishment of new power stations by the IEC: The Reform allows for the IEC, by means of a wholly owned subsidiary, to receive new generation licences for two natural gas combined cycle gas turbine ("CCGT") units, with a total installed capacity of about 1,200MW.[3,4] These units are expected to commence their operation during 2023-2024.[5]

System management

The role of the system manager is defined broadly under the ES Law, and includes, among other things, responsibility for the optimisation of the sector, operation of electricity trading mechanisms, the statutory and engineering planning of the transmission network, long-term planning and forecasts of demand in the market, etc. The Reform mandated that the system manager shall be a separate Government-owned company. As of November 1, 2021, the system management activity has been transferred completely from the IEC to Noga.

Transmission inspection

Under the Reform, the IEC will establish a new transmission inspection administration to operate the transmission and transformation system in accordance with the instructions of Noga.

Transmission and distribution segments

The Reform allows the IEC to continue to transmit and distribute electricity as a monopoly through separate profit centres. To maintain the stability and quality of the electricity supply, the IEC will develop the transmission network according to a development plan to be approved in accordance with the ES Law. Furthermore, the IEC's distribution segment licence includes an obligation to enter into agreements with renewable energy IPPs that connect directly to the distribution network for the sale and injection of their electricity to the distribution network.

Supply segment

To maintain stability in the supply sector (sale of electricity to the consumers), the Reform requires opening the supply segment to competition. The supply segment for high-voltage, extra-high-voltage and ultra-high voltage consumers (mainly large business consumers) has been fully opened up to competition; the IEC remains a default supplier and is prohibited from competing by offering different tariffs from the tariffs determined by the EA.

By contrast, the supply segment for low-voltage consumers (including household consumers) will be gradually opened up to competition so that throughout the Reform period the IEC's market share will not fall below 60%. Should the IEC's market share drop below 60%, the IEC will be permitted to compete in the household consumer segment subject to regulation to be established.

In February 2020, the EA published a decision setting the principles for opening of the low-voltage supply segment for competition, in an initial quota of up to 400MVA, 100MVA of which was allocated for household consumers (which was further increased in 2021 to 1,400MVA and 100MVA, respectively). This decision is the first milestone towards the opening of the supply market for competition.[6] In the framework of this decision, and for the first time, new players are invited to apply for the receipt of a supply licence, even if they do not operate a power station (subject to their compliance with certain regulatory requirements, mainly demonstrating that they have an equity of at least NIS50 million). Such new suppliers will purchase the electricity for their consumers from the system manager. In response to the EA decision, 26 licenses were already granted by the EA as of January 2022.

Organisational change and streamlining plan

In the framework of the structural change, the IEC undergoes a streamlining process, in which the number of the IEC's permanent employees will be reduced by 25% between 2018 and 2025. Some of the employees will move to Noga or to the companies that purchase the IEC's generation units.

The Reform also places an emphasis on environmental considerations, mandating the closure of the coal-fired power stations in order to reduce the use of polluting fuels, and defining multi-year goals for promoting and increasing the use of renewable energy.

The Reform opens up great potential for new players to enter the energy market in Israel as well as enabling existing participants in the market to increase their exposure in the electricity sector.

Special increase of the electricity tariffs

On 28 July 2022, the EA published its decision regarding the annual update of the electricity tariffs (as of 1 August 2022). According to the decision, the cumulative tariff for domestic consumers is increased by about 13.6% compared to 2021.[7] The EA explained that most of the increase is due to the soaring coal prices and changes in the exchange rates. The EA further explained that the raise does not cover all costs, but taking into consideration the substantial decrease in the use of coal over the next years, this tariff might cover the costs during the upcoming years.

Upstream oil and gas sector

Since the final approval of the Natural Gas Framework ("NGF") in 2016, there has been notable progress in implementing its ultimate goals, ie upstream investment has reinitiated and the Leviathan field has been developed and is supplying gas to various IPPs and to clients in Jordan and Egypt. The Karish and Tanin reservoirs were purchased in 2016 by Energean Israel Limited ("Energean") which is expected to supply gas to the local market in Q3 2022 and NewMed sold its entire holdings in the Tamar reservoir, in accordance with the NGF framework.

In June 2020, the EA published its third competitive tender process for granting a single exploration block, 257km in size, in the northern part of the Israeli Exclusive Economic Zone ("EEZ") (block 72). The offered block is mainly comprised of the Alon D licence area previously held by Noble and NewMed. The identity of the winner of the offered exploration block is pending the Ministry of Energy's ("MOE") decision.[8]

In January 2022, the IEC signed an amendment to its gas supply agreement with the partners of the Tamar reservoir. According to public records, the amendment included, among other things, a reduction of the gas price purchased under the agreement, in exchange for its extension until the end of 2031 and the IEC's commitment to purchase additional gas quantities.[9]

Moreover, due to the geopolitical changes in Europe caused by the war in Ukraine and the increasing demand in Europe to diversify its energy sources as a result of such geopolitical changes, in May 2022, the Minister of Energy directed its office to promote a fourth competitive tender for natural gas exploration in the EEZ. [10] In addition, on 15 June 2022, Israel, Egypt and the EU signed a Memorandum of Understanding ("MOU") for collaboration on trade, transportation and the export of natural gas to EU countries.[11]

Increased demand for natural gas

In 2021, the increase in natural gas consumption from the Israeli natural gas fields has continued both in the domestic and export markets and reached a total of 19.50 billion cubic metres ("bcm") (an increase of 21% in comparison to 2020). During 2021, the local market consumed a quantity of 12.33bcm, and such consumption is likely to increase throughout 2022.[12]

Additionally, the Government has taken several steps that are expected to increase demand for natural gas by replacing other fuels. For example, in 2021, as part of a pilot led by the MOE, a residency neighbourhood was connected to the natural gas grid for the first time. Under the pilot, a further 31,000 residential units are expected to be connected in the next three years.[13] Furthermore, the MOE approved during 2021 grants of up to NIS37 million to accelerate the connection of various hospitals to the natural gas distribution network. These grants are in addition to a budget of NIS40 million approved by the government in July 2020, to support hospitals in their connection the natural gas network.[14]

In May 2021, as part of the MOE's efforts to accelerate the connection of the industry sector to the natural gas grid, the MOE announced the allocation of NIS200 million to the gas distribution network companies to accelerate the connection of additional industrial consumers. This grant is followed by former grants which have already been allocated, and which have provided financial support to the natural gas network expansion, in order to connect hundreds of consumers in Israel.[15]

Gas explorations in the mediterranean

Since October 2020, Israel and Lebanon have undertaken negotiations under U.S mediation to reach agreements regarding the delimitation of the maritime border between both countries. The issue became highly relevant following the past discovery of gas fields in the Mediterranean, and the common interest to exploit the economic benefit of its production. The tension between the two countries spiked in June 2022 when Energean's Floating Production Storage and Offloading vessel (FPSO) arrived near the Israeli Karish reservoir for final preparations for gas production in 2022. As a result, in August 2022, U.S mediator Amos Hochstein arrived in the Middle East to continue the indirect negotiation process between the two countries under his supervision.[16]

In light of the diplomatic normalisation agreement signed between Israel and the United Arab Emirates ("UAE") in September 2020, new collaboration opportunities are expected between the two countries. To date, several working groups have been established to promote the potential cooperation in the energy and technological sectors, for example, natural gas, renewable energy and cyber protection.[17] As part of such cooperation, in October 2021, the Israeli pipeline company EAPC reported that it had signed a preliminary deal to help transport oil from the UAE to Europe, via a pipeline that connects the Red Sea city of Eilat and the Mediterranean port of Ashkelon.[18]

Additionally, as mentioned above, NewMed sold its share in the Tamar field to a UAE company.

Further to these developments, Israel is a part of a new initiative for the developing the natural gas fields in the Mediterranean, the East Mediterranean Gas Forum (EMGF), established in 2019 and its current members are Israel, Egypt, Italy, Greece, Cyprus, Jordan, France and the Palestinian Authority. On 22 September 2020, the member countries signed a formal charter which will enable the forum to carry out its business in the Mediterranean area,[19] and a recent conference of the EMGF was held in February 2022.[20]

Further to the MOU signed on 5 November 2019 for connecting Israel's EEZ via the EastMed pipeline to Europe through Greece, in a manner that will allow the export of natural gas from Israel to Europe; in March 2021, Israel Natural Gas Lines Ltd. ("INGL") signed an addendum to the MOU for the design of the connection to INGL's transmission system. According to the addendum, the parties will promote the planning and licensing of the facilities within Israel's EEZ.[21]

Recent developments in Israel's renewables sector

Since ratifying the Paris Agreement in 2016, Israel has made strides in promoting the use of renewable energy in energy generation. In recent years, the EA has published several competitive procedures and issued a variety of conditional generation licences for wind, biogas, photovoltaic ("PV"), hydroelectric and biomass technologies. As of 2021, the annual production potential of domestic energy consumption in renewables accounted for 9.4%.[22]

Israel is continuing to promote the renewables sector. Government Resolution 465 issued of 25 October 2020 approved the MOE plan concerning the Energy Economy Objectives for 2030.[23] The plan stipulates that by the end of 2030, the objective for electricity generation from RES is 30% of Israel's total electricity consumption and sets a corresponding intermediate target of 20% by 2025.[24] The plan seeks to decrease the use of polluting fuels in the electricity sector by replacing them with more efficient energy sources, including natural gas and renewable energy. The decision sets out principles for promoting greenhouse gas ("GHG") reduction, as well as a plan of cooperation between various governmental ministries to promote the establishment of renewable energy production facilities in built-up areas in order to minimise land use. The decision further examines the establishment of a loan fund for the planning and construction of renewable energy systems as well as storage facilities, and also to instruct the EA to promote corresponding regulation to support the 2030 targets.[25]

As an example of inter-ministerial initiatives, in May 2021, the MOE together with the Ministry of Agriculture and Rural Development jointly published an invitation to receive proposals from entrepreneurs to examine the feasibility of dual-use of agricultural land for electricity generation from solar energy, while maintaining yielding agriculture in parallel in those areas.[26] In November 2021, the results for the competitive process were published and tariff was established at NIS0.175kW/h (about US$0.05kW/h).[27] Additionally, as part of the EA's efforts to promote electricity generation from renewable energy, several competitive procedures, mainly concerning PV installations, have been conducted from 2017 to 2021, helping to increase competition, decrease the feed-in tariff rates and develop Israel's renewable energy sector. These competitive procedures are expected to continue, alongside the publication of new tenders seeking to promote new projects in Israel's renewables sector. As an example, during the second half of 2020, the EA published two tenders for PV facilities with combined storage capacity of 168MW and 609MW, respectively.[28]

Furthermore, in April 2021, the MOE published a national master plan for the energy economy's infrastructure for the years 2030 and 2050 (Roadmap for a low-carbon energy economy by 2050). The plan sets a reduction target of 85% for GHG emissions by 2050, as well as a commitment to shut down coal-fired power plants by 2025 and a reduction of GHG emissions in the electricity sector at a rate of between 75% and 85% by 2050.[29] The plan also aims to increase energy efficiency by an annual permanent percentage (1.3%) and expand the use of renewable energies by increasing solar energy production and grid connection to neighbouring countries, including Europe. The plan also examines the potential use of nuclear energy.

In May 2022, the MOE together with the EA published the operative master plan for reaching the energy economy objectives for the years 2025 and 2030 (as described above). The plan mapped three key areas of action in order to achieve these objectives: network limitations, regulation barriers and land availability. The MOE formulated about 50 policy measures for overcoming such barriers. Among them, expanding the land permits for local authorities, setting arrangements with the Ministry of Defence in order to construct PV installations on army facilities and establishing a new regulation for importing electricity from neighbouring countries.[30]

On 28 August 2022, the EA published its decision for the update of the demand hours clusters of the electricity tariffs due to changes in the electricity generation segment, such as the entrance in big quota of renewable energy facilities. The changes which the EA are promoting include (i) cancelling shoulder rates; (ii) reducing the amount of peak hour clusters and increasing the amount of Off-peak clusters; (iii) shifting the hours of peak hour clusters to evening time (5pm-10pm in winter and shoulder seasons and 5pm-11pm in summer season) instead of noon time; and (iv) substantially increasing the difference between the tariffs during the peak hour clusters and the off-peak clusters in the summer and winter seasons. The main purpose of the EA in changing the demand hour clusters of the electricity tariffs is to reflect the true economic value of electricity generation costs and reduce cross subsidies between different consumer groups.[31]

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Overview of the legal and regulatory framework in Israel

A. Electricity

A.1 Industry structure

Nature of the market

Until recently, there was no competition in the Israeli electricity sector. Since its incorporation in 1923 and the grant of concessions by the British Mandate authorities, the Mandate-era tariff setting remained largely unchanged until the enactment of the Electricity Sector Law 1996 ("ES Law"). The ES Law was intended to introduce competition into the sector by unbundling the various electricity activities and determining timetables regarding the revocation of the Israel Electric Corporation ("IEC") licences (or at least partially) in order to create reforms for unbundling and privatising the various electricity sectors, culminating in the IEC Reform approved in 2018.

In order to incentivise the entrance of IPPs into the market, the provisions of the ES Law and its regulations require the system manager (until recently the IEC) to purchase electricity from cogeneration, conventional, and renewable energy Independent Power Producers ("IPPs") (with the level of purchase commitment varying among the different technologies). This critical requirement serves as the financial and practical backbone for overhauling the structure of the electricity market by facilitating and enabling the market entrance of IPPs and has resulted in their rise in the generation sector.

The IEC in its capacity as transmission system licence holder must provide electricity transmission services and back-up electricity supply to customers of a licensed IPP (which hold a supply licence), when such electricity is sold to private customers in exchange for a tariff. In addition, related regulation includes provisions designed to provide security and comfort to financing entities of IPP projects in light of regional security concerns. These provisions, detailed in the Book of Standards (see section A.3) deal with the allocation of risk and responsibility between certain IPPs (which meet certain requirements) and the System Manager in case of force majeure, especially with respect to events of war and terror attacks. During the COVID-19 pandemic, the Electricity Authority ("EA") granted relief to certain IPPs who were in the process of constructing their facilities (mainly photovoltaic ("PV") facilities), by granting an extension of the deadlines of their construction under the regulation applicable to them.[1]

Key market players

For more than 90 years, Israel's electricity sector has been dominated by the IEC, a vertically integrated state-owned enterprise responsible for transmission, distribution, and system management, with the generation and supply sectors gradually moving over to IPPs.

On 3 June 2018, the Israeli Government ("Government") approved the details of the structural change in the electricity sector and the IEC, the most comprehensive reform in the Israeli economy to date ("Reform"). The Reform is being implemented gradually up to 2026, starting with the sale of Alon Tavor station with a capacity of about 583MW which was concluded in December 2019, the sale of Ramat Hovav power station with a capacity of about 1,135MW in December 2020, and followed by the recent sale of Hagit-East power station site with a capacity of about 660MW which was concluded in December 2021. The Reform is being continued through the upcoming sale of the Eshkol Power Station Sites (see the 'Recent developments in the Israeli energy market' article). The Reform is expected to have a significant impact on the electricity sector and the general economy.[2]

Further to the electricity sector Reform, the IEC's dominance is being diminished so that while the IEC still operates both the transmission and distribution grids almost exclusively and provide back-up services for customers and power producers, as of 1 November 2021, the system management is no longer controlled by the IEC and its share in the production segment is targeted to decrease to 45% by 2026.

As of 1 November 2021, the system management activity has been transferred completely from the IEC to Noga – Israel Independent System Operator Ltd ("System Manager" or "Noga").

As a supplier, the IEC will purchase from Noga electricity for its consumers and will pay Noga for this electricity according to generation component tariff and system management tariff. In turn, Noga will pay the IEC as an electricity generator, the generation component and additional tariffs for the services provided by the IEC.

Moreover, the Reform stipulates that the IEC will remain the last resort supplier in the supply segment. The supply of electricity to high voltage, extra-high voltage and ultra high voltage consumers is open to full competition however the tariff to be offered by IEC is the tariff as determined by the EA. In the low voltage supply segment, the IEC will be permitted to compete alongside other suppliers once the market share of its customers in the low voltage supply segment drops below 60%. If the number of IEC consumers in the low voltage supply segment falls below 75% the IEC will be permitted to provide cyber services, 'smart home' and 'energy efficiency' services for its consumers.

In addition, and as part of the trend to increase competition in the electricity sector, in November 2021, the Ministry of Energy ("MOE") published regulations to promote competition in the production sector. These regulations, which were enacted in consultation with the competition commissioner, are intended to create certainty for IPPs and prevent the exploitation of market power by, among other things, determining the maximum holdings percentage in the production sector of the electricity market one player can hold. The regulations set a ceiling of holding of no more than a 20% share in the planned quota for power stations of the same kind of technology, and with respect to wind technology, the holding limit has been set at 60% to ensure that more than one IPP operates in the wind technology market.[3]

The Minister of Energy ("Minister") has overall responsibility for the electricity sector, including overseeing the IEC and Noga (which are government owned companies). The Minister's role is complemented by the EA, the Ministries of Finance, Interior, and Environmental Protection, as well as the Government Companies Authority.

Regulatory authorities

The ES Law established the EA, entrusting it with the exclusive and independent authority to set electricity tariffs. The EA is also responsible for establishing standards and criteria to ensure service quality.

Legal framework

The ES Law is the primary legislation applicable to the electricity sector. This law is designed to regulate the electricity market for the good of the public while guaranteeing reliability, availability, quality and efficiency, and creating conditions for competition and minimising costs.[4]

The ES Law spearheaded efforts to reform the monopolistic sector dominated by the IEC, and to that end establishes the parameters and timetable for such sectoral reform, beginning with replacing the IEC's all-encompassing concession with several licences, which are subject to the provisions of the law.[5]

Implementation of EU directives

Although not a member of the European Union ("EU"), Israel is involved in certain activities of the EU electricity market and its regulators. For example, Israel's EA has adopted several European directives relating to consumer protection (eg the Third Energy Package), resulting in collaboration with Austria's regulator, E-CONTROL. The EA has also consulted with Britain's Ofgem and the Council of European Energy Regulators ("CEER") and has recently adopted EU directives regarding smart meters. The EA is also a member of the Association of Mediterranean Energy Regulators, supported by the organisation's members, the European Commission and CEER.[6]

A.2 Third party access regime

Under the Reform, the IEC remains responsible for nearly 100% of all transmission and distribution networks controlling the ultra-high voltage lines, switching stations, substations and the mid- and low-voltage lines. Regarding infrastructure to guarantee third party access, under the ES Law the IEC which is defined under the ES Law as an Essential Service Provider ("ESP") must:

- provide service to the public in a non-discriminatory, reliable and efficient manner; and
- provide IPPs with infrastructure and backup services.

The ES Law establishes the requirements to receive transmission and distribution licences. However, due to Israel's limited market, land area, and existing infrastructure in the electricity market, it appears that the IEC, as a natural monopoly, will retain control of transmission functions and of most of the distribution networks. Nevertheless, as part of the streamlining steps that the IEC has taken under the Reform, it shall invest at least NIS3 billion annually in the development of a smart and modern transmission grid that will improve the quality of electricity supply and allow a wide entry of IPPs.[7]

A.3 Market design

The ES Law and its accompanying regulations establish the primary regulatory framework for Israel's electricity sector.[8] Following the enactment of the ES Law, the MOE and the EA were firmly established as the primary regulators responsible for licensing as well as the determination, monitoring, and updating of the electricity tariffs. The ES Law sets out the tariff calculation method (see section A.4). The ES Law further requires the EA to set operation criteria for ESPs, focusing on the standard, nature, and quality of the services provided, and to supervise an ESP's performance and compliance thereunder. The criteria are detailed in the EA's Book of Standards, which is intended, among other things, to address the interaction between the IEC (in its role as an ESP) and its customers (including IPPs). The Book of Standards is updated on a regular basis (usually quarterly).[9]

A.4 Tariff regulation

The EA is responsible under the ES Law for establishing a variety of electricity tariffs, distinct for each market segment. Tariffs for the public are calculated taking into account the IEC production costs which the EA elects to recognise, including a fair rate of return on capital/equity. The EA further establishes the tariffs Noga or the IEC must pay for electricity purchased from IPPs. In setting tariffs, the EA is guided by the overarching principle of minimising costs to consumers, while maintaining the appropriate economic balance and certainty, to encourage further development of the sector by entrepreneurs. The EA reviews the components comprising the recognised costs in the tariffs annually and elects whether to publish revised tariffs accordingly. Such tariffs include generation component and grid tariffs (which take into account recognised costs and assets in transmission, distribution and supply).

In 2015, the EA published its decision introducing the system management services tariff and announcing the elements that would compose the system management services cost:

- system balancing;
- back-up services;
- ancillary arrangements in the electricity sector; and
- administrative costs.[10]

The tariffs are being updated annually (usually in January) as part of the annual update of tariffs in the electricity market.

At the end of 2018, the EA issued a decision regarding the tariff base for the transmission and distribution segments for the years 2018-2022, which introduced for the first time a fixed component, to be paid regardless of the actual consumption from the electricity grid. This fixed component of the tariff was increased gradually from 2019 until 2022 to allow for an adjustment period to the consumers.[11]

On 28 August 2022, the EA published its decision to update the demand hours clusters of the electricity tariffs due to changes in the electricity generation segment, such as the entrance in big quota of renewable energy facilities. The changes include: (i) canceling shoulder rates; (ii) reducing the amount of peak hour clusters and increasing the amount of Off-peak clusters; (iii) shifting the hours of peak hour clusters to evening time (5pm-10pm in winter and shoulder seasons and 5pm-23pm in summer season) instead of noon time; and (iv) substantially increasing the difference between the tariffs during the peak hour clusters and the off-peak clusters in the summer and winter seasons. The main purpose of the EA in changing the demand hour clusters of the electricity tariffs is to reflect the true economic value of electricity generation costs and reduce cross subsidies between different consumer groups.[12]

A.5 Market entry

Licensing regime

The ES Law stipulates that all electricity sectors, including generation (subject to certain exceptions), transmission, supply, distribution, self-production, and system management (all as defined under the ES Law), are subject to a licensing regime, primarily under the supervision of the EA, with some authority reserved for the Minister. Applicants seeking a generation licence generally initially apply for a conditional licence for electricity generation, which, following the fulfilment of certain milestones, is converted to a Permanent Production Licence ("PPL") (typically issued for 20 years) which is required in order to commercially operate an IPP and produce electricity. To sell electricity to private consumers, an IPP must obtain a supply licence in addition to its PPL.

The holder of a transmission, distribution or system management licence is considered an ESP. The Minister is vested with authority regarding the issuance, extension, and revocation of certain licences (generation and supply licences exceeding 100MW; distribution licences for activities exceeding 5% of the yearly usage; transmission licences; and system management licences). The EA retains the authority to grant the balance of licences, in addition to approving changes in licence holder control, pledges or grants of security interests in and over licence assets.

The ES Law details the requirements for new market participants to enter the electricity sector as follows:

- Possession of an electricity generation licence granted by the EA for facilities above 16MW (no licence is required for self-consumption facilities or renewable energy facilities in a capacity of up to 16MW). Licences of over 100MW need an additional approval from the Minister.
- Possession of/rights to land for the construction of production facilities; planning permits may be required for facilities over 50MW.
- Ability to connect to the electricity grid and the natural gas network (if applicable). The applicant must prepare a connection feasibility survey and may be required to prove technical ability and experience.
- Financial capacity: An applicant may be requested to provide financial reports and funding information. A minimum of 20% equity is required to fund the construction of electricity generation facilities, to be injected upon financial closing.[13]

Since December 2016, with the publication of the first competitive procedure by the EA for the construction of small-medium PV facilities, the main way to enter to the Israeli renewable energy market is by participating in the EA competitive procedures (see section D.3). In evaluating an application to receive a licence (if applicable), the EA considers, among other things, the public good, the contribution of the potential licence to the level of public services, and whether competition is boosted. If approved, the applicant must deposit a guarantee and financial commitment letters.

One of the main reasons for the delay in IPPs penetrating the market was the lack of available natural gas, however, this barrier disappeared once the Tamar reservoir came online in 2013 (Tamar is a natural gas field in the Mediterranean Sea off the coast of Israel).

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

PSOs in the Israeli electricity sector consist of discounts offered to certain populations, in accordance with amendments to the ES Law and regulations instituted by the Minister. Those entitled to certain discounts in electricity, provided they satisfy certain requirements of the National Insurance Institute, include pensioners, Holocaust survivors, persons with disabilities, single parents, disabled veterans and terror victims.

Smart metering

As of 2020, smart metering has not been adopted as a compulsory practice.

In October 2021, the EA published its decision regulating the principles for installation of smart meters among domestic consumers, such smart meters to be installed (by the IEC) in a case of connection of new consumers or the replacement of old meters. The smart meters to be installed shall comply with the requirements of the principles of Article 20 of Directive No. 944/2019 of the EU – 'Functionalities of smart metering systems'. The decision set a target of deployment of up to 450,000 smart meters until 2023, with an option to deploy additional 150,000 smart meters subject to the EA's instructions.[14]

Electric vehicles

As part of the MOE's efforts to reduce the use of refined petroleum products and to encourage the transition to 'green' transportation, it is promoting the deployment of recharging stations for electric vehicles ("EVs") to support the emerging EV market. In November 2018, the MOE published four requests for proposals, focusing on supporting the establishment of fast and ultrafast (DC) recharging stations nationwide as well as the establishment of slow (AC) recharging stations in public spaces, semi-public spaces and workplaces. In September 2021, the MOE published its expectation to have more than 2,500 recharging stations installed by the end of 2021.[15] During late 2021, the MOE has announced its intention to promote three additional requests for proposals for supporting the installation of new recharging stations for Electric Vehicles nationwide in a budget amounting NIS24 Million.[16] In addition to the above, in September 2021, the MOE published a public tender for the establishment of charging stations for electric vehicles in buildings used by the

Government. As part of the tender, the MOE provides about NIS2 million for the installation of AC charging stations with a capacity of 22Kw/h. Moreover, in August 2022, the MOE published an investment program for promoting the expansion of charging stations for electric vehicles in private parking lots amounting NIS8 million (about US$2.5 million) and the financing of an additional 1,122 charging stations in public parking lots nationwide.[17]

A.7 Cross-border interconnectors

Israel has no electricity interconnectors with neighbouring countries and is therefore an electricity island.

In March 2021, Israel, Greece and Cyprus signed a trilateral memorandum of understanding regarding the construction of a cable project linking Israel's electric grid with the EU, ie the EuroAsia InterConnector, which is an EU Project of Common Interest. The link is planned to consist of submarine direct current cables and high-voltage direct current onshore stations in the respective countries with a 2,000MW capacity. It is expected to span over 1,500km and will help secure the energy supply of all three countries and the EU.[18] The commissioning plan is estimated as follows for the various project segments:

- Cyprus-Israel commissioning in December 2023; and
- Cyprus-Crete commissioning in December 2023.[19]

Upon completion, the new power line will include Greece, Crete, Cyprus and Israel, creating an opportunity for Israel to guarantee energy security of supply,[20] especially as it is an electricity island.

In November 2022, the United Arab Emirates (UAE), Jordan, and Israel signed a cooperation agreement that would broker an exchange of renewable energy and water between Jordan and Israel. The agreement consists of two interdependent and contingent components. The first, Prosperity Green, plans for solar PV plants generating capacity of 600MW to be built in Jordan, with all clean power produced to be exported to Israel. The second, Prosperity Blue, is a sustainable water desalination program to be built in Israel to supply Jordan with up to 200 million cubic metres ("m^3") of desalinated water. Feasibility studies for the project commenced in 2022. [21]

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Small oil reservoirs exist in Israel, however, domestic production fulfils a negligible portion of demand. Most crude oil in Israel is used in the transportation and industrial sectors, and in 2020 it constituted 40.3% of the total fuel mix for energy production in Israel.[22]

Gas

Nature of the market

Due to significant discoveries of natural offshore gas surrounding Israel's shores, with consumption beginning in 2004, natural gas production and demand has risen dramatically. The overall demand for natural gas for electricity generation, industrial purposes and private consumption is projected to rise to about 452 billion cubic metres ("bcm") during the period 2018 to 2042.[23]

Following these discoveries of natural offshore gas, a duopoly emerged in the market, dominated by Noble Energy Mediterranean Ltd. (later acquired by Chevron Corporation) ("Noble") and NewMed Energy Limited Partnership ("NewMed", formally known as 'Delek Drilling Limited Partnership'). The duopoly's prominence was further bolstered when Egypt ceased its gas exports to Israel in 2012, leaving Tamar as the sole reservoir supplying Israel. The rise of the duopoly, and the decisions of the Competition Authority that followed regarding natural gas sold by Tamar for the long term, sparked a heated public debate on the lack of competition and extended to gas prices, domestic needs, and export limits. The chaos resulted in the appointment of an inter-ministerial taskforce charged with restoring stability to the sector by reaching a comprehensive agreement. The taskforce's efforts resulted in the Natural Gas Framework ("NGF") agreed between the Government, Noble and Newmed in August 2015, aiming to introduce competition into the upstream market.

Pursuant to the NGF, Noble and NewMed transferred their rights in the Karish and Tanin Reservoirs to Energean in December 2016 and NewMed sold all of its rights in the Tamar Reservoir in December 2021.[24]

Energean, the purchaser of the Karish and Tanin fields under the NGF has signed several gas sales contracts with buyers including large power plants and the largest industrial groups in Israel, thereby introducing substantial competition into the natural gas market.

Key market players

The total amount of recoverable gas reserves (2P and 2C) found offshore Israel as of 1 January 2021 is estimated at over 921bcm.[25] As of 2021, most of these discoveries are held by Noble (Chevron) and Newmed. The IEC, as Israel's main electricity provider, remains an anchor buyer for natural gas domestically, however, due to the Reform, natural gas operated IPPs are increasing their market share.

Regulatory authorities

The MOE is the governmental regulator of all natural resources and energy in Israel, overseeing their use and management including that of oil and gas. The Natural Resources Administration in the MOE regulates the exploitation of natural resources in Israel and includes two professional units, ie the Petroleum Unit overseeing upstream petroleum (headed by the Petroleum Commissioner ("PC"), appointed by the Minister) and the Mines and Quarries Unit that manages minerals. The PC is responsible for issuing petroleum rights and overseeing the exploration and production activities granted by these rights.

The Natural Gas Authority ("NGA") of the MOE, is responsible for overseeing the downstream natural gas industry, by issuing licences in the transmission, distribution and storage sectors, supervising licence holders, and setting tariff and service provision standards, for each downstream sector.

Israel's transmission system is operated by Israel Natural Gas Lines Limited ("INGL"), a state-owned enterprise; the distribution system is divided into six regions, each operated by a private company under a licence issued by MOE tender (see section B.2).

Legal framework

The Petroleum Law 1952 ("Petroleum Law") and its related regulations and guidelines establish the legal framework governing the upstream exploration and production of oil and gas, while the Natural Gas Sector Law 2002 ("NG Law") regulates the downstream natural gas sector. The Petroleum Law applies to both oil and natural gas (petroleum is broadly defined in the Petroleum Law); the NG Law applies only to natural gas.

The Petroleum Law covers exploration, production and exploitation in the onshore and offshore areas of Israel, including its continental shelf. It is not permitted to explore for or produce petroleum without holding a permit, licence or lease, as applicable (see section E).

The Petroleum Law allows for two types of mechanisms to grant petroleum rights: licences or a competitive bidding process. During the last decade, exploration rights were granted solely through a competitive bidding process (see section E).

The NG Law governs midstream and downstream activities, establishing a licensing regime for natural gas infrastructure, including distribution, transmission, storage and liquefied natural gas ("LNG") facilities. Following the major gas discoveries, the Government introduced new legislation, regulations and guidelines to address the increase in consumption of natural gas in Israel, focusing on such issues as installation safety and building laws.

A notable and pending piece of legislation is the Marine Areas Bill 2017,[26] which intends to determine the scope of application of Israel's laws in marine areas beyond Israel's territorial waters, including in Israel's Exclusive Economic Zone ("EEZ") where all Israel's natural gas discoveries, to date, are located.

Pursuant to these objectives, the proposed law seeks primarily to:

- define and delimit the marine areas (in accordance with the principles of international law and the United Nations Convention on the Law of the Sea)[27] where the State has authorities and rights;
- establish the rights and authorities of the State in the various marine areas (territorial waters; internal waters; contiguous zone; and the EEZ) by detailing the specific laws applicable in these areas; and
- ensure the development and utilisation of the EEZ and the continental shelf, while protecting the marine environment.

Due to the current political deadlock in the parliament in Israel, it is still unclear whether this Bill will be legislated or not.

Additional upstream regulation includes Government Decision no. 2592 (Support of Small and Medium Sized Fields, 2 April 2017), which introduces a number of infant protections to support market entry of such reservoirs. Decision 2592 adopts, among other things, the Natural Gas Sector Regulations (Management of the Natural Gas Sector During Times of Emergency), which establish backup arrangements between suppliers in the event of gas supply failure.

Implementation of EU gas directives

As a non-member of the EU, Israel is not obligated to comply with EU Directives, however it is influenced by their content in constructing and operating gas infrastructure and in formulating its domestic regulation. For example, the distribution network is being built to comply with the European Standard EN-12007 (see section B.2).

B.2 Third party access regime to gas transportation networks

Natural gas is transported at high pressure (above 16 Bar) through a state-owned transmission system constructed and operated by INGL. The transmission system spans about 700km, transporting gas to high pressure shippers, such as the IEC and IPPs.[28] This system connects with the distribution network at facilities used to reduce gas pressure, and from there deliver natural gas locally to industrial low pressure consumers. The distribution network is constantly being expanded and is intended to reach all natural gas consumers. Transmission and distribution tariffs, licences and rules are issued by the NGA.

Despite the considerable efforts and progressive legislation enacted, the connection of the distribution network to low pressure industrial gas consumers is still incomplete and suffers from significant delays. Government Decision no. 352 (5 August 2015) established the goal of connecting 450 factories to the distribution network by 2020.[29] As of 2021, out of hundreds of potential consumers of gas (power plants, cogeneration, industries, etc), only about 150 have been connected to the distribution network, and the MOE strives to advance the connection processes by providing government grants.[30] For example, on 29 August 2022, the MOE and the Ministry of Economy and Industry published a government grants plan in an aggregate amount of about NIS50 million to businesses that meet certain criteria and wish to connect to the distribution network.

Israel is divided into six regions for the purposes of natural gas distribution, each of which is constructed and operated by a single distribution licensee granted through a public tender. Licensees have exclusivity for the construction, operation and maintenance of the distribution network for a period of 20 to 25 years.

Title transfer between sellers and buyers of natural gas takes place at the delivery point (entry into the transmission system).

As licensees under the NG Law have exclusivity, nation-wide or regionally, and as consumers must purchase infrastructure services through these licensees, the NGA provides protection for consumers by establishing and supervising infrastructure rates (transmission and distribution), requiring licensees to provide their services to all consumers without discrimination, and enforcing safety standards.

Under the NG Law, agreements for the use of the transmission and distribution networks are subject to NGA approval and must be published on the NGA and licence holder websites.

B.3 LNG terminals and gas storage facilities

To enhance security of supply, in January 2013, a Floating Storage and Regasification Unit ("FSRU") was inaugurated for the import and storage of natural gas. The FSRU is capable of importing LNG in an annual amount of about 2.5bcm, with a storage capacity of 138,000m^3. As Israel's third gas supplier, Karish, is expected to begin operations by 3Q 2022, the FSRU is expected to cease its operation in 2023.[31]

B.4 Tariff regulation

The NGA sets capacity and throughput transmission fees, connection fees, and balancing fees for use of the INGL transmission grid. The NGA similarly approves and supervises distribution tariffs in the distribution network. The licensees supply access to the distribution network and services to third parties based on standard uniform contracts, which are approved by the NGA.

Transportation charges include connection fees, capacity and throughput fees and balancing fees. Connection fees are a one-time payment, mainly covering the capital costs of the pressure regulation and measuring stations for a transmission consumer. The ongoing fees for transporting the gas in the transmission system are comprised of a capacity fee (about 90% of the total transportation fee) and a throughput fee.

Transmission rates are determined by the NGA *ex-post*, and are updated in accordance with the costs for the expansion of the transmission system; distribution rates, however, are established via tender and are updated every six months according to the linkage formula stipulated in the licence.

B.5 Market entry

The construction and operation of the following natural gas infrastructures require a licence from the Minister under the NG Law:

- transmission networks or any part thereof;
- storage installations;
- LNG installations; and
- distribution networks or any part thereof.

Transmission licences are primarily granted by tender; however, the NG Law permits the Ministers of Energy and Finance to grant a licence due to 'urgent needs in the energy economy', or in the event of an unsuccessful tender process,[32] in which case the Minister may grant a transmission licence to a state-owned enterprise,[33] as was the case with INGL.

The distribution network is constructed and operated by distribution licensees (private companies) who won a tender process. Under the Natural Gas Sector Regulations (Manners and Conditions for Provision of Distribution Licence) 2008, tender applicants for a distribution licence must provide certain information (eg financial capability, controlling shareholders, and professional knowledge and experience).

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

There are no PSOs for the gas sector.

Smart metering

There is currently no smart metering for the gas sector.

B.7 Cross-border interconnectors

During 2016, an agreement was signed between the Leviathan reservoir partners and the Jordanian Electric Company for the supply of natural gas up to a total volume of about 45bcm for a period of about 15 years.[34] In addition, since 2017, the Tamar reservoir has been exporting natural gas from Israel to two Jordanian plants on the Jordanian side of the Dead Sea. Later that year, INGL signed a transmission agreement with NBL (a wholly owned company of the Leviathan Partners) for transporting natural gas to the Jordanian Electric Company.[35] This export agreement has a total volume of about 3bcm for a period of 15 years.[36] For the purpose of transmission of gas to the Jordanian border, INGL finished developing an additional 23km export pipeline for Jordan.[37]

Regarding Egypt, there is a natural gas transboundary pipeline from El-Arish in Egypt to the shores of Israel ("Pipeline"). The Pipeline was inactive during the years 2012-2019 until NewMed purchased the rights of the Pipeline.[38] In 2018, two agreements were signed for the export of natural gas to Egypt from the Tamar and Leviathan reservoirs to Dolphinus Holdings Limited, and the gas flow has started as of the start of 2020.[39] In January 2021, INGL signed a transmission agreement with Chevron Mediterranean Limited (which operates the Leviathan and Tamar reservoirs) for transmission of natural gas to Egypt from the Tamar and Leviathan reservoirs through the Israeli national transmission system. Such transmission by INGL is expected to commence in March 2023.[40] In February and March 2022, INGL signed transmission agreements with Chevron Mediterranean Limited for transmission of natural gas from Leviathan and Tamar reservoirs respectively to Egypt via Jordan.[41]

Additionally, there are plans to facilitate a joint cross-border interconnector from Israel to Greece via Cyprus and thereafter to Italy and other South European countries. Known as the EastMed pipeline (an EU Project of Common Interest), the project envisages a 1,300km^2 offshore and a 600km^2 onshore pipeline.[42]

C. Energy trading

C.1 Electricity trading

In accordance with Government efforts to reform the electricity market and boost competition, certain statutory requirements are imposed on the IEC and IPPs entering this sector. Certain IPPs sell all of their generation to the System Manager, while others sell only their surplus.[43] As such, electricity trading is encouraged by the regulatory framework and is implemented via bilateral purchase agreements. In its role as system manager, Noga is responsible for balancing activities and load management.

C.2 Gas trading

There is no trading hub for natural gas. The sale of natural gas takes place by means of contracts between the gas suppliers and consumers, which are not regulated; however, these sales are subject to the competition laws if applicable under the circumstances. No price control has been implemented; however, under the NG Law, gas suppliers and gas marketing companies have reporting obligations regarding profits from sale of natural gas.

Gas marketing agreements (marketer-consumer) and gas trade agreements (supplier-marketer) are unregulated commercial contracts.

D. Nuclear energy

Israel does not currently possess nuclear energy generation facilities. In the 1990s, the Geological Survey of Israel conducted a study to locate potential sites for nuclear power plants in Israel. In 2016, the MOE resumed its efforts to study potential placements. To that end, a Ministry of Finance planning committee presented a detailed national energy infrastructure plan to the National Planning and Building Council and recommended that nuclear plants contribute 5% of Israel's energy needs by 2030, increasing to 15% by 2050. To date, however, it appears that no concrete measures have been taken to advance the use of such technology.

E. Upstream

The Petroleum Law outlines the licensing regime for the exploration and production of petroleum (see section B.1) and provides for three types of rights, two relevant to the exploration stage and the third to production.

A preliminary permit may be granted for a maximum of 18 months with no maximum area limitation and allows the prospector to conduct preliminary investigations (excluding test drilling) to ascertain the prospects for discovering petroleum in the permit area. The preliminary permit holder is entitled to request a priority right on the permit area, which, if granted, provides the preliminary permit holder priority to receive a licence in the permit area in the event hydrocarbons are discovered.

A petroleum licence grants an exclusive right for further exploration work and requires drilling wells. The maximum term of a licence is seven years, with an area limit not to exceed 400km^2. The initial licence term is three years, extendable to a maximum of seven years (and an additional two years on discovery of petroleum).

Upon discovery of petroleum, the licensee has a statutory right to receive the third type of right, a production lease, for a maximum area offshore of 250km^2. An initial lease may be granted for 30 years, extendable to a maximum of 50 years. A lease grants the leaseholder the exclusive right to explore for and produce petroleum in the lease area and requires production in commercial quantities. A leaseholder is liable for paying the market value at the wellhead of royalties of 12.5% of the quantity of petroleum produced from the lease area, excluding the quantity of oil and gas used in lease operations.

In accordance with the Law for Promotion of Competition and Reduction of Concentration (2013), the PC must consult with the Director General of the Competition Authority before granting preliminary permits, licences and leases under the Petroleum Law.

To be granted a petroleum right, the Petroleum Regulations 2016[44] stipulate that an applicant must: (i) meet the requirements under the Petroleum Regulations 1952; (ii) prove that it (or any member of the group it is a part of) may be approved as operator; and (iii) present its compliance with the requirements regarding financial capacity.

The PC will not authorise a corporation as an operator if it fails to demonstrate professional experience of at least five years as an operator within the ten years prior to the application, alongside other requirements specified in the Petroleum Regulations 2016.

With respect to financial capacity, the applicant company (or group) must have total assets of at least US$400 million and shareholders' equity of at least US$100 million (demonstrable through its controlling shareholder). The operator will be considered as having the requisite financial capacity if it has total assets of at least US$200 million and shareholders' equity of at least US$50 million. Additionally, the operator must demonstrate economic capability, as more fully described in the Petroleum Regulations 2016.

In December 2020, as part of a governmental plan for reducing the 'regulatory burden' in the Israeli economy, the PC amended its guidelines regarding the procedure and requirements to receive his approval (as required under the Petroleum Law) for the transfer or encumbrance of petroleum right under the guidelines.[45] The latest amendment to the guidelines largely eliminated the need to provide the PC with the consent of all other holders of a certain petroleum right as a precondition for receiving PC approval for such transfer or rights.

Tender process for oil and gas exploration

In November 2016, the MOE published its first tender process for new exploration areas in Israel's EEZ. The competitive process, in which 24 exploration zones with a maximum area of 400km^2 each were auctioned, concluded in November 2017, with the announcement of the bid winners as Energean (five licences) and an Indian consortium (one licence).[46]

In November 2018, the MOE announced a second offshore bid round of exploration licences for 19 blocks to be issued in five zones in the southern portion of Israel's EEZ.[47] The bid round included competition considerations and granting preference to new market entrants in order to increase the diversity of licence holders and successful bidders.

The second bid round was concluded in October 2019, with the granting of 12 new exploration licences to a consortium comprised of British companies Cairn and Pharos, and the Israeli company Ratio (eight licences); the remainder were granted to Energean and Israel Opportunity (four licences). A third competitive procedure was published in June 2020 under which the MOE offered a single exploration block, no. 72, in the northern part of the Israeli EEZ.[48] As of August 2022, the successful bidder of the third competitive procedure has not been announced.

Additionally, in January 2021, the MOE announced that it was preparing the fourth competitive procedure under which 25 blocks were mapped and will be consolidated into six blocks with a maximum size of up to 1,600km^2 each. To date, the publishing date of this competitive procedure has not been announced but in May 2022, the Minister directed its office to promote such publication.[49]

F. Renewable energy

F.1 Renewable energy

Israel's renewable energy market framework was defined in recent years through several Government decisions, which among other things, established objectives for renewable energy electricity generation, issued quotas for various renewable technologies, established emissions reduction goals, and granted incentives and promotions for the implementation of renewable energy projects and initiatives.

The ES Law[50] requires renewable energy IPPs to obtain generation licences for facilities above 16MW. In addition, the ES Law requires ESPs to provide infrastructure services, connect renewable energy facilities to the grid, and purchase electricity from licensed renewable IPPs. This purchase obligation is an essential mechanism facilitating the entry of these renewable energy IPPs in the market.

The economic mechanism used to encourage individuals and companies installing renewable energy is the Feed-in-Tariff ("FiT"), accompanied by a series of quotas for installations of each technology type.

The main technologies operating in Israel's renewables sector are:[51]

- solar (PV/thermo-solar), which currently represents more than 90% of the renewable energy sector;
- wind;
- biogas;
- biomass (solid waste, landfills and wastewater); and
- hydroelectric.

In September 2015, Government Decision no. 542 established a target for the generation of electricity from renewable energy at a rate of 10% by 2020, 13% by 2025 and 17% by the end of 2030.[52]

On 29 July 2020, the Minister of Energy published his decision (adopting EA recommendations) to set up a policy aiming to increase electricity generation from renewable energy to 30% of all electricity consumption in 2030.[53] Accordingly, Government Resolution 465, issued in November 2020 (which updated Government Decision no. 542), stipulates that by the end of 2030, the target for electricity generation from renewable energies will be 30% of total electricity consumption, and sets a corresponding intermediate target of 20% by 2025. In addition, a rapid governmental action plan was developed, in collaboration with a variety of governmental ministries. This program deals with the promotion of solar energy production in Israel, including the promotion of solar energy in local authorities.[54] For example, in April 2021, the MOE together with the Ministry of Agriculture published a 'call for proposals' to submit preliminary proposals for the dual use of land - combining agriculture with PVs (Agri-PV).[55]

In addition, in April 2021, the MOE published a national road map plan for the energy economy's infrastructure for the years 2030 and 2050 (Roadmap for a low-carbon energy economy by 2050), reflecting MOE's strategic goal of reducing emissions.

The objectives of the roadmap are as follows:

- Reduction of 23% in greenhouse gases ("GHGs") in the energy sector by 2030, and by 80% by 2050, respectively;
- Reduction of 30% in GHGs in the electricity sector by 2030, and 75% to 85% by 2050;
- Increasing energy efficiency by an annual percentage improvement of energy intensity of 1.3%; and
- Cessation of coal use from 2030.

the GHG in the electricity sector will be achieved by various means, such as increasing solar energy production in the electricity generation, grid connection to neighboring countries including Europe, examining the use of nuclear energy and the use of blue hydrogen derived from natural gas.[56]

FiT in solar energy

The EA introduced FiTs for facilities operating with solar technology, commencing in 2006 without any distinction between the various technologies. The base tariffs offered in the beginning of the last decade were very high compared to the rates offered today in the framework of competitive procedures published by the EA. For example, the FiT offered in January 2011 for the first cumulative installed capacity of up to 60MW (out of market wide quota of 500MW) was NIS1.11 for each Kw/h (US$0.34).[57] the FiT offered has been drastically reduced since 2012 due to the EA decision to change the basis of tariff calculation for solar PV FiTs above 50KW, adding a linkage to the Bloomberg New Energy Finance ("BNEF") module and inverter indices (the Solar Spot Price Index and Utility Index (ie SSPI).[58] In doing so, the EA intended to avoid the creation of 'solar bubbles' in which FiTs become quickly disconnected from actual costs and entrepreneurs retain unreasonable margins.

The FiT for each separate project is determined by applying the formula shortly before the financial closure of the project. Due to the above linkage and the drop in prices of PV panels, the base tariff for PV facilities in 2016 connected to the distribution network was reduced to NIS0.2952kW/h (about US$0.09kW/h), reflecting sharp declines in equipment costs.[59]

Since 2016, the EA published competitive processes to determine rates for the generation of electricity by PV technology. Under these procedures, the rights to develop new PV projects under the quotas allocated to PV facilities will be granted via the Vickrey auction. The rate to be paid to all winning proposals is the rate of the best proposal not selected, ie the first proposal on the list after the selected proposals.

Following the Minister's decision to add a quota of 1,600MW to solar installations, in order to meet the Government objective of 10% renewable energy production by 2020, during 2017 - 2020, the EA published several competitive procedures focusing mainly on small-medium PV facilities with and without storage, (with a capacity ranging from 51kW to 10MW) connected to the distribution network. The proceedings resulted in a decrease in prices with a winning tariff of NIS0.199kW/h (about US$0.061kW/h) in the first procedure of 2017 to a tariff of NIS0.1745kW/h (about US$0.0535kW/h) in the most recent procedure of 2020.[60] In addition, from 2019-2021, the EA published four competitive procedures for PV facilities that will be built on large roofs and water reservoirs with a winning tariff of NIS0.2333kW/h (about US$0.0715kW/h) in the first competitive procedure of 2019[61] and a tariff of NIS0.1705kW/h (about US$0.0512kW/h) in the 2021 procedure.[62]

For large PV installations with capacity above 10MW, in 2018 the EA published[63] the first tender for large PV systems to be connected to the extra-high and ultra-high voltage transmission network. This tender was a great success and in May 2019 the EA published the list of the successful bidders with a total quota of 239.64MW and a record low rate of tariff ranging from NIS0.1444 to NIS0.1668kW/h (about US$ 0.0443kW/h to US$0.0512kW/h, respectively).[64]

In November 2020, a tender was published by the Ministry of Finance together with the MOE for or the construction of the largest solar power plant in Israel (300MW), near Dimona.[65] The tender included a requirement for integrating energy storage in batteries into the project. In December 2021, the winning bidder was selected. The winning bid had a price of NIS0.0858kW/h.[66]

As a result of the above tender processes, the tariff rates are subject to competition and are steadily declining.

To further encourage the private sector to generate electricity using PV and wind technologies, in December 2016 the Israeli Parliament enacted the Law for Encouragement of Investments in Renewable Energies (Tax Incentives for Production of Electricity from Renewable Energy) 2016 approving tax reductions to private households generating electricity with renewable energy (an income tax exemption up to NIS24,200 (about US$7,422).[67]

FiTs in wind energy (for facilities above 50kW)

Following Government Decision no. 3483 of July 2011, the EA introduced in October 2011 a course of action for constructing and establishing wind facilities for electricity generation. This decision established an accumulated quota of up to 800MW and also included a formula for the basic tariff (linked to the CPI, the US dollar and the euro). The quota for wind energy generation was further reduced by 70MW (which was diverted to PV technology), following a Government decision in October 2014.[68]

The basic FiT was updated by the EA in February 2015, adding a substantial linkage of the FiTs to the Wind Turbine Price Index (WTPI – Class III) published by BNEF in addition to the previous linkage to the CPI, the US dollar and the Euro. This resulted in a substantial decrease in tariffs.[69]

In February 2017, the EA further updated the FiT in order to adjust the energy output of the facilities to a lower and more conservative wind speed. The updated tariff is linked to the CPI, the US dollar, the euro, the Wind Turbine Price Index (WTPI – Class III), and additional components. This decision also distinguished between facilities connected to the transmission network (extra-high and ultra-high voltage) and facilities connected to the distribution network (low and high voltage), by setting different tariffs which vary according to the set quota.[70] In May 2020, the linkage formula was updated to represent the average of the last three quota of the WTPI – Class III index in order to better represent the world market fluctuations of the wind turbines prices.[71]

Said decision updated the FiT for wind facilities connected to the transmission network, for the first 300MW, at NIS0.539kW/h (about US$0.1654) and for the balance (301 to 730MW) at NIS0.499kW/h (about US$0.1531), while the FiT for wind facilities to be connected to the distribution network for the first 300MW was set at NIS0.506kW/h (about US$0.1553) and for the balance (301 to 730MW) at NIS0.468kW/h (about US$0.1436).[72]

Israel has taken important steps in promoting renewable energy generation and substantial integration of technologies in the electricity market. The feasibility of generating electricity from wind and PV technologies is relatively high compared to other renewable energy technologies due to Israel's ample sunshine, however, regulatory and planning procedures have occasionally posed obstacles or led to delays. The MOE has been collaborating with the Ministry of Defence, the Nature and Parks Authority, and the planning authorities to remove planning and implementation barriers in these sectors.

F.2 Renewable pre-qualifications

Pre-qualifications requirements regarding renewables may vary and are tailored to each competitive procedure, tender, governmental grant, etc. With respect to big projects (above 16MW) the pre-qualifications requirements usually include requirements, such as the applicant demonstrating financial capacity and experience. Additionally, where the applicant is already active in the Israeli market, competition considerations are also considered by the EA prior to granting a production license.

F.3 Biofuel

Biofuel technologies are currently in the research and entrepreneurial stages in Israel, primarily in the fields of transportation and alternative fuels. Although, Government decisions on renewable energy have noted the importance of promoting such new alternative fuels.

G. Climate change and sustainability

G.1 Climate change initiatives

As of the end of 2021, renewable energy constitutes about 8% of the energy produced in Israel.[73] On 14 November 2016, Israel ratified the Paris Agreement at the UN Conference on Climate Change (ie COP-22). Under the Paris Agreement, Israel aims to achieve a 26% reduction in its 2005 GHG emissions by 2030.[74]

Additionally, the Ministry of Environmental Protection is a member of the Climate Impact Research and Response Coordination for a Larger Europe (ie CIRCLE-2) and has been a task member of several working packages and participated in cooperative efforts such as InfoBase and Circle-Med.[75]

Further to the MOE's roadmap, in July 2021, the Government published Resolution 171 ("Resolution 171") which promulgates the Government's plan to transition the Israeli market into a low carbon emissions economy targeting an 85% reduction in carbon emissions by 2050. Resolution 171 also sets intermediate targets of (i) a 27% reduction in carbon emissions by 2030; and (ii) a 30% reduction in carbon emissions in the electricity sector. The resolution further instructs the Energy Minister to establish renewable energy targets for 2050.[76]

In October 2021, the Israeli Prime Minister and Minister of Energy issued a joint statement announcing commitment to reducing GHG emissions to Net Zero by 2050. To achieve this goal, the joint statement proclaimed that the Government would look to (i) develop the country's seasonal energy storing and carbon trapping capabilities; (ii) promote the construction of green infrastructure projects; (iii) promote educational initiatives; and (iv) invest in green energy research and development.

Moreover, on 1 August 2021, the Government published Resolution 286, which furthers the Government's low-emissions agenda established in Resolution 171. Resolution 286 instructs the Finance Minister to amend the fuel excise tax order of 2004 and the Customs Tariff and Goods Purchase Tax of 2017, and apply increased taxation on fuels per ton of carbon emissions, and establish new tariffs for fossil fuels excise and purchase taxes that gradually increase on an annual basis starting 2023 according to a tariff rate schedule published by the Government.[77]

G.2 Emission trading

At present, Israel does not have any emissions trading schemes in place. However, in recent years, through both regulatory efforts and comprehensive national studies, Israel is examining GHG emission levels and evaluating different reporting and reduction mechanisms, eg voluntary reporting.

G.3 Carbon pricing

On 1 August 2021, the Government published Government Resolution 286 regarding the pricing of GHG emissions. This resolution stipulates, among other things, that the Minister of Finance should be responsible for amending the Order of Excise on Fuel 2004 (Imposition of Excise) as well as the Order of Custom and Exemption Rate and Purchase Tax on Goods 2017, so it can lead to a gradual increase on an annual basis starting in 2023, according to a tariff rate schedule. Consequently, the excise and purchase tax levied per ton of Natural Gas is set to increase from NIS29.00 in 2023, and thereafter gradually in accordance with the tariff rate schedule to NIS170.00 from 2028 onwards.[78] It is important to note that to date, the Minister of Finance has not published the required amendments to the orders detailed above and therefore, the application of the Carbon Pricing mechanism might be delayed.

G.4 Capacity markets

N/A

H. Energy transition

H.1 Overview

As mentioned above, Government Resolution 465, issued in November 2020, stipulated that by the end of 2030, the target for electricity generation from renewable energy will be 30% of the total electricity consumption in Israel, and also set a corresponding intermediate target of 20% by 2025.

In order to successfully achieve the targets above, in May 2022 the EA published a hearing for its proposed 'Multi-Year Plan for Meeting Consumption Goals from Renewable Energies'. The plan presents the additional electricity generation that is required to meet the targets under the Government Decision, the regulatory outline that the EA is promoting in connection with such targets, the procedures that it intends to carry out, and how it expects to deal with the challenges arising from a significant integration of renewable energy in the Israeli market. For example, the EA plans to approve a new development plan for the transmission network and to initiate a new development plan for the distribution network.[79]

H.2 Renewable fuels

Hydrogen

The Chief Scientist of the MOE provides financial support for the development of projects for the production of hydrogen and for conducting pilots to test projects feasibility. In 2021, the Chief Scientist provided total support of about €30.5 million (NIS101 million).[80]

As for recent developments, in April 2022, the Chief Scientist and the NGA published a request for the public comment on the issue of a hydrogen pilot and to receive proposals from the public for the use of hydrogen as an energy source in industry, either by using pure hydrogen or by using natural gas diluted with hydrogen at different rates. The intention is that the examination of these projects will be done at the factory level, ie the use or conversion of the factory systems or part of them to the use of pure or diluted hydrogen as an energy source and the examination of the safety, engineering, energetic, environmental and economic consequences of this step.[81]

Ammonia

Ammonia is not currently a regulated fuel in Israel.

H.3 Carbon capture and storage

Israel has not taken any substantial regulatory steps to promote carbon capture and storage ("CCS"), and the private sector appears to be in its technological infancy in this field. In 2018, Israel published its first storage resource assessment.[82]

A 2018 study submitted to the Ministry of Environmental Protection recommends that to further CCS deployment in Israel, additional steps should be implemented, including adopting public policy, providing economic incentives, establishing national climate action plans, etc.[83]

As the need for electricity storage increases due to the reliance of renewable energy in Israel on solar technologies, the EA and the MOE are promoting regulations for the rapid integration of storage technologies to meet the Government's renewable energy goals.

H.4 Oil and gas platform electrification

N/A

H.5 industrial hubs

In November 2021, the governments of Israel, Jordan and the United Arab Emirates signed a declaration of intent for the construction of solar energy and water desalination facilities that will enable a joint response to the climate challenges in the region. The declaration includes the implementation of two international programs, the first includes the establishment of PV facilities and energy storage capacity in Jordan and exporting of the produced energy to Israel. The second plan includes the construction of a water desalination facility in Israel and exporting of the treated water to Jordan. During 2022, the parties carried out feasibility studies for the implementation of these projects.[84]

H.6 Smart cities

Between 2013-2015, an administration within the MOE operated a 'Smart Cities Administration' which tried to provide a comprehensive perspective on the issue of smart cities and bring together all the government ministries and relevant factors to address the issue. However, in February 2016, the administration's activity was stopped by the Director General of the MOE at the time before it had time to formulate a clear policy and methods of action. Presently, there is no single overall framework for the subject of smart cities, but specific projects managed by various government ministries alongside local authorities.[85] [86] For example, The establishment of a smart street cleaning system in Haifa, which enables an improvement of the cleanliness level in the city; setting smart protocols for street lighting in Ashdod, which enable a potential saving of hundreds of thousands of euros each year. Moreover, the local authority in Tel Aviv has formulated a complete concept of the smart city based on the involvement and partnership of the residents by using a smart resident card which provide personalised information, among other things, about events in the card holder's areas of interest, or certain alerts that may be related to the card holder's area of residence.[87]

I. Environmental, social and governance (ESG)

The Capital Market Authority published a paper on 18 November 2021, according to which an investment committee of an institutional investor must determine an investment policy that also refers to ESG considerations. In this framework, the investment committee is instructed to formulate rules and to develop ESG expertise as ESG considerations may have a material impact on the performance of the investment portfolio.[88] Furthermore, the Capital Market Authority determined that the institutional investor will specify in its policy framework the environmental and social considerations it considers as part of the management of the investment portfolio of such entities.[89]

In addition, the State Comptroller also referred to the issue of ESG considerations in investments and recommended that the entities audited by him shall incorporate ESG rules into their investment policies.[90]

Prominent ESG considerations, regarding environmental issues, which will be included in the investment considerations of the institutional bodies will be dealing, among other things, with air, water and soil pollution, and the promotion of clean energy infrastructures.[91]

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89. Capital Market Authority published 'Investment Management', dated 18 November 2021 (Hebrew), available at www.gov.il/BlobFolder/dynamiccollectorresultitem/notice-2021-9-13/he/chozer-2021-9-13-pdf.pdf.

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91. The MOE published 'The Insurance and Savings Capital Market Authority publishes a circular draft instructing to refer to ESG considerations that may affect the investment performance of institutional entities', dated 4 May 2021 (Hebrew), available at www.gov.il/he/Departments/news/press_esg.

Energy law in Italy

Recent developments in the Italian energy sector

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New incentive schemes

In November 2021, the Italian Government ("Government") enacted a Legislative Decree on 8 November 2021 ("RED II Decree"),[1] which incorporated the Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources.

The RED II Decree aims to accelerate sustainable growth in Italy by pursuing the targets of a minimum share of 30% of Italy's energy coming from renewable sources in gross final energy consumption. This includes a reduction of 55% compared to 1990 levels of greenhouse gas (GHG) emissions by 2030.

To achieve these targets, the RED II Decree provides two key measures: (i) the enactment of new public subsidies schemes; and (ii) the simplification of permitting proceedings.

Regarding public subsidies, the RED II Decree outlines general principles to be implemented in greater detail by following ministerial decrees which will:

- replace the Decree of 4 July 2019 (so called-RES 1 Decree) and set out a new incentive regime based on downward auction procedures, power quotas for different technologies and specific categories of interventions; and be applicable to renewable plants other than biogas, biomass, geothermal, off-shore wind, and thermodynamic solar plants; and
- set out an incentive regime for biogas, biomass, geothermal, offshore wind, and thermodynamic solar plants.

Until the new scheme is enacted, the regime set out by RES-1 Decree continues to apply to photovoltaic ("PV"), wind, hydro, sewage treatment and landfill gas plants.

The RED II Decree also provides for: an extension of the incentive regime to ground-mounted PV plants located in unused agricultural areas; the creation by the GME (*Gestore dei Mercati Energetici S.p.A.*) of a digital platform for power purchase agreements; guidelines for the identification of suitable and unsuitable areas for the installation of renewable energy plants; and the simplification of permitting procedures for the construction of charging infrastructures for electric vehicles (EVs). Additionally, the RED II Decree establishes that, from 2022, part of the annual profit from carbon dioxide (CO_2) auctions will be used to cover the costs of supporting renewable energy sources ("RES") and energy efficiency development.

Local energy communities and self-consumption systems

The RED II Decree amends the legal framework for local energy communities ("LECs") and self-consumption systems ("SCSs"). Such legal framework shall be completed by a number of implementing decrees setting out a new incentive regime.

From a general standpoint, the RED II Decree extends the perimeter of the incentives to LECs and SCSs.

In particular, incentives will be granted to SCSs and LECs provided that:

- plants have a capacity not higher than 1MW and enter into operation after 15 December 2021; and
- collective self-consumers or community members are connected to the grid under the same primary cabin.

Incentives will be granted only in relation to the portion of energy generated by the plant and shared within the configuration. The relevant application must be submitted on the date of entry into operation (no auctions or rankings are provided).

An additional ministerial decree will define the criteria and procedures for accessing the interest-free financing of up to 100% of eligible costs provided under the National Recovery and Resilience Plan ("NRRP"). This was created for the development of LECs in small municipalities through the construction of RES plants and energy storage systems.

Biomethane

The Italian Ministry for Ecological Transition ("MiTE") – now the reorganised and redenominated Ministry of Environment and Energy Security – has enacted the Decree 15 September 2022[2] ("New Biomethane Decree"), published on the Official Gazette of the Italian Republic No. 251 of 26 October 2022 and entered into force on 27 October 2022. This sets out a new public subsidies scheme for production of biomethane under component 2 of mission 2[3] of the NRRP, for an overall amount of about 1.7 billion.

It aims to promote the production of biomethane injected into the natural gas grid and produced in compliance with the sustainability requirements of Directive 2018/2001/EU (so-called "RED II") by granting (i) a capital contribution amounting to 40% of eligible expenditure, and (ii) a specific incentive tariff.

The New Biomethane Decree implements Article 11 of Legislative Decree 8 November 2021, No. 199 ("RED II Decree", transposing in Italy the RED II Directive), which defines general criteria for granting, through public competitive procedures, non-repayable contributions on eligible expenditure incurred for investment for efficiency interventions, and partial or total revamping of existing biogas plants, for new biomethane production plants.

The previous incentive regime, set out by Ministerial Decree 2 March 2018[4] ("DM 2018"), originally applicable to plants entering in operation by 31 December 2022, has been recently extended[5] to plants that will enter in operation by 31 December 2023.

Simplification of the permitting proceedings

Since 2020, the Government has enacted several provisions aimed at simplifying the permitting proceedings for construction and operation of energy generation plants from renewable sources and the installation of storage systems.[6]

Most recently, through the Annual competition law for 2021,[7] the Government aims to simplify the administrative procedures relating to RES by adopting one or more legislative decrees within 12 months of the Annual competition law entering into force (ie, by 27 August 2023).

In this simplification work, the Government must:

- reorder the existing legal framework in order to ensure a higher degree of legal certainty and simplification of the procedures;
- ensure the uniqueness, accuracy, and completeness of the legal framework; and
- simplify the relevant permitting procedures, remove existing category of permits to simplify and expedite the permitting procedures, set out fixed terms for their conclusion, and promote the business, installation, and repowering of plants for domestic use.

Abolishment of the protected supply service

Law no. 124/2017 provided for the abolishment of the protected supply service (*servizio di maggior tutela*).[8] Following several postponements, the abolishment of this regime started from 1 January 2021 for business customers, and it will start from 1 January 2023 for household customers.

End customers that do not opt for the free market regime for the first six months will be supplied by the same supplier as the protected supply service but under different economic conditions. Afterwards, they will be served by a last-resort service supplier selected through public tenders, without prejudice to the right to opt for the fee market at any moment.

Hydrogen, industrial hubs, and smart cities

Upon the release of the Hydrogen Strategy by the European Commission in 2020, the sustainable production of hydrogen has become an investment priority within the Next Generation Europe Plan. Accordingly, in the context of the NRRP, €3.2 billion is allocated for the research, testing, production and use of hydrogen.

The NRRP also targets the gradual decarbonisation of industry and aims at developing technological and industrial leadership in the main transition sectors that are internationally competitive (PV systems, turbines, hydrolysers, fuel cells batteries) and at reducing the dependence on imported technologies, creating jobs and growth. The NRRP also envisages the creation of hydrogen hubs and the development of smart cities.

Smart city projects in Italy show an increased awareness of the importance of the topic compared to the past. Nevertheless, applications continue to weigh less than 8% on the internet of things (IoT) market.

Energy price increase: the measures on 'super profits'

To mitigate the impact on end customers of price increases in the energy sector, Article 15 of Law Decree no. 4 of 27 January 2022 ("Law Decree 4/2022"), converted into Law no. 25 of 28 March 2022, was implemented by the Government to establish a two-way compensation mechanism for energy prices, applicable from 1 February 2022 to 30 June 2023[9] to power injected into the grid from:

a) PV plants with a capacity higher than 20kW benefitting from fixed premiums under the 'energy account' incentive schemes (*Conto Energia*) and which are not dependent on market prices; and

b) solar, hydroelectric, geothermal, and wind power plants with a capacity higher than 20kW and which are not benefitting from incentive mechanisms entered into operation prior to 1 January 2010.

The GSE calculates the difference between:

- a reference price set out in Law Decree 4/2022 for each market zone; and
- a market price equal to:
  1. for the plants under (a) above, as well as for the plants under (b) above, from solar, wind, geothermal and run-of-river water sources, the hourly zonal market price of power; or for supply agreements entered into before 27 January 2022 that do not comply with the exemption requirements described below, the price established under those agreements; and
  2. for plants under (b) above, other than those referred to in number (1), at the monthly arithmetic average of the hourly zonal market price of power; or for supply agreements entered into before 27 January 2022 that do not comply with the exemption requirements described below, at the price set out in those agreements.

The mechanism does not apply to power sold through supply agreements entered into before 27 January 2022, provided that they are not linked to price trends in the energy spot markets and, in any case, are not entered into at an average price of 10% higher than the reference prices outlined by Law Decree 4/2022. This is limited to the duration period within the aforementioned contracts.

Separately, Article 37 of Law Decree no. 21 of 21 March 2022, converted into Law Decree no. 51 of 20 May 2022, sets out an extraordinary tax contribution (the "Special Contribution") to be paid by energy companies carrying out the following activities:

- power generation for sale purposes;
- production of methane gas production or extraction of natural gas;
- retail of power, methane gas and natural gas;
- cultivation, distribution and sale of oil products;
- import of power, natural gas, methane gas, or oil products for sale purposes; or

- introduction in Italy of the above goods from other member States of the European Union (EU).

The Special Contribution is not due by companies organising and operating platforms for the exchange of power, gas, environmental certificates, and fuels.

The tax base is equal to the balance increase among active and passive transactions between 1 October 2021 and 30 April 2022, compared to between 1 October 2020 and 30 April 2021 (the "Increase").

If the balance referred to in the period between 1 October 2020 and 30 April 2021 is negative, the tax base is equal to zero.

The Special Contribution is equal to 25% of the tax base if the Increase is higher than €5,000,000.

The Special Contribution must not be paid if the Increase is lower than 10%.

The Special Contribution must be paid as follows:

- 40% by 30 June 2022 (advance payment); and
- 60% by 30 November 2022 (full payment).

Special tax schemes must meet certain requirements stated by the Italian Constitutional Court in previous case precedents. In particular, they must:

- be objectively grounded;
- be reasonable and proportionate; and
- not have discriminatory effects.

Furthermore, the Special Contribution is not deductible from income taxes.

Through the aforementioned provisions, the Government aimed to limit any super profits made by energy generators due to the increase in energy prices. Several legal commentators and market associations view the so-called measures on super profits as unconstitutional.

Climate change litigation

In June 2021, the environmental association 'Giudizio Universale' filed a class action before the Court of Rome against the Government. According to the plaintiff, the Government allegedly failed to adopt sufficient measures to prevent climate change, in breach of several international and European laws. The case is still pending; however, in June 2022, a public hearing was held. Over the next few months, the Court of Rome will assess further evidence to decide whether the Government is liable for its inaction in fighting climate change.

Endnotes

1. Published on the Official Gazette of the Italian Republic of 30 November 2021, No. 285, and entered into force on 15 December 2021.
2. "Development of biomethane, according to criteria to promote circular economy - biomethane production".
3. Mission 2 "Green revolution and ecological transition", Component 2 "Renewable Energy, Hydrogen, Grid and Sustainable Mobility", Investment 1.4 "Development of biomethane according to criteria to promote the circular economy", for an overall amount of Euro 1,730.4 million.
4. "Promotion of the use of biomethane and other advanced biofuels in the transportation sector".
5. Under Ministerial Decree 5 August 2022.
6. Ref. to so-called Simplification Decrees, ie Law Decree 16 July 2020, No. 76, converted into Law 11 September 2020, No. 120, and Law Decree 31 May 2021, No. 77, converted into Law 29 July 2021, No. 108.
7. Law 5 August 2022, No. 118 – Annual law for the market and competition 2021 (*Legge annuale per il mercato e la concorrenza 2021*), published on the Official Gazette on 12 August 2022, No. 188.
8. Households and small business customers connected at a low voltage, with less than 50 employees and a yearly turnover not exceeding €10 million are entitled, if they do not opt for the free market, to be served according to the economic and contractual conditions set out by ARERA (*servizio di maggior tutela*).
9. The deadline was originally set at 31 December 2022 and was postponed by Law Decree 9 August 2022, No. 115, converted into Law 21 September 2022, No. 142.

Overview of the legal and regulatory framework in Italy

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Italy is fully liberalised. The process of liberalisation began with the enactment of Legislative Decree 79/99, which was then progressed by subsequent amendments to and integrations of the decree, mainly relating to the generation, import, export, sale, and purchase of electricity.

Transmission and distribution activities are subject to an Italian Government ("Government") concession and are reserved for the Transmission System Operator ("TSO") and local distributors. In certain cases, transmission and distribution activities are operated through privately owned grids.

Key market players

The transmission system is operated by Terna S.p.A. ("Terna"), the Italian TSO and majority owner of the Italian high voltage and extra high voltage national transmission grid. Terna operates in a natural monopoly.

The distribution market is fragmented. E-distribuzione S.p.A., a member of the Enel Group, is the distribution system operator ("DSO") of the largest electricity distribution grid in Italy. Before the privatisation and liberalisation process, Enel Group S.p.A. (formerly Enel S.p.A.) was a state-owned monopoly in the energy sector. Presently, Enel Group S.p.A. is a multinational energy company and one of the world's leading integrated electricity and gas operators.

Gestore dei Servizi Energetici S.p.A ("GSE") is a Ministry for Business and Made in Italy ("MIMIT") controlled company responsible for the promotion and development of renewable energy sources ("RES") and energy efficiency. GSE manages the incentive mechanisms, implements Italian energy policies, certifies the renewable origin of electricity, and verifies RES plants to ensure a strict allocation of incentives. GSE is also the parent company of other public interest companies operating in the energy sector, including Acquirente Unico-AU S.p.A., Gestore dei Mercati Energetici-GME S.p.A. and Ricerca sul Sistema Energetico-RSE S.p.A.

Since the liberalisation of the electricity sales market on 1 July 2007, Acquirente Unico S.p.A. ("AU") has been responsible for purchasing electricity, thereby minimising the costs and risks associated with electricity procurement for customers who benefit from the protected supply service (*servizio di maggior tutela*). Under the protected supply service regime, households, and micro-enterprises with a capacity of up to 15kW, are entitled, if they do not opt for the free market, to be served according to the economic and contractual conditions set out by the Regulatory Authority for Energy, Networks, and the Environment (*Autorità di Regolazione per Energia, Reti e Ambiente*) ("ARERA"). Micro-enterprises are those with less than ten employees and an annual turnover not exceeding €2 million. The protected supply service will be abolished by 2023.

The Gestore dei Mercati Energetici S.p.A. ("GME") manages the power, gas and environmental[1] markets and was initially vested exclusively with the organisation and economic management of the wholesale power market. GME also operates a platform for ancillary services (ie, the dispatching service market) ("MSD") on behalf of the TSO, through which it collects the bids and communicates the results. MSD is also a platform for the registration of over the counter ("OTC") transactions.[2]

Regulatory authorities

MIMIT is responsible for the business and industry sectors and other economic activities, including the energy sector.

The Ministry of Environment and Energy Security ("MASE") is the government body responsible for the implementation of environmental policies. MASE was created following the redenomination and reorganisation of MITE (ie the former Ministry of Ecological Transition), with functions in the fields of: protection of biodiversity, ecosystems and marine-coastal heritage, protection of the territory and water, climate change and global warming policies, sustainable development, energy efficiency and the circular economy, integrated waste cycle management, remediation of Sites of National Interest (SIN), environmental assessment of strategic works, combating air-noise-electromagnetic pollution and the risks arising from chemicals and genetically modified organisms.

The Ministry promotes good environmental practices, sustainable mobility, and urban regeneration according to sustainability criteria. ARERA is the National Regulatory Authority ("NRA"). ARERA was established by Law no. 481/1995 in order to protect the interests of users and consumers, promote competition, and ensure efficient, cost-effective and profitable nationwide services of the required standard. ARERA is an independent authority, and national legislative and executive bodies hold no influence over it. However, ARERA[3] must set out a regulatory framework for the activities of market operators in line with the general principles and objectives introduced under primary legislation. Measures enacted by ARERA are subject to judicial control, eg when a regulatory measure enacted is illegal, unfounded, not proportionate, etc. ARERA is also responsible for the enforcement of REMIT provisions in Italy.

The Autorità Garante della Concorrenza e del Mercato ("AGCM") is the antitrust authority and is responsible for monitoring and ensuring fair competition and consumers' protection in the energy sector.

The Treasury for Energy and Environment Services (*Cassa per i servizi energetici e ambientali*) ("CSEA") is a public economic entity subject to the supervision of ARERA, MIMIT and the Ministry of Finance. The CSEA's main function is the collection of certain tariffs from operators. These tariffs flow into dedicated management accounts and are disbursed according to rules set out by ARERA to companies operating in the sectors of renewable and assimilated sources, energy efficiency, service quality, interruption (*interrompibilità*), equalisation, system research, nuclear decommissioning, and projects beneficial to consumers, along with others.

Legal framework

Legislative Decree 79/99, as subsequently amended, began the liberalisation of the Italian electricity market by establishing, among other things, that:

- transmission activity is reserved to the Italian State ("State"), and assigned by licence to the TSO;
- distribution activity is subject to licences, all expiring on 31 December 2030, granted within each municipal area by the Ministry for Industry, Commerce and Crafts (now, MIMIT);
- transmission and distribution tariff charges are mainly applied in relation to the energy consumed; and
- general system charges (*oneri generali di sistema*), the tariff structure of which was reformed by the NRA in December 2017,[4] are mainly applied by way of increases to the transmission charges and, therefore, are applied in relation to the energy consumed.

The legislative framework provided by Legislative Decree 79/99 did not, however, regulate the following interconnected aspects:

- the existence of private electricity systems, in which energy transmission and distribution activity are carried out in the absence of a specific licence; and
- how the general system charges should be allocated, in a context where (as a result of the development of private grids with internal production) there is a progressive misalignment between the electricity taken from the public grid and the amount of energy consumed.

In subsequent years, therefore, many provisions were introduced and aimed at (i) defining private electricity systems[5] and (ii) regulating the relevant tariff regime.[6] Presently, the framework of private electricity systems is separated into two categories:

- the Simple Systems of Generation and Consumption (*sistemi semplici di produzione e consumo*), ie, simple electricity systems (one generator-one consumer) in which the transport and delivery of electricity to final consumers is not considered a transmission and/or distribution activity, but rather as a measure of energy self-sufficiency; and
- the Closed Distribution System (*sistemi di distribuzione chiusi*) in line with Article 28 of the Third Electricity Directive, ie, complex electricity systems (one or more generators-one or more consumers) in which transport and delivery of electricity to final consumers is considered a transmission and/or distribution activity. For distribution activity, MIMIT, ARERA, the DSOs and private grid operators must agree upon a legal framework setting out the regulation of a sub-licence regime, which is applicable to a Closed Distribution System owner, for operating transmission and/or distribution services that are supplied to final consumers in the private grid.

Implementation of EU electricity directives

In respect of full ownership unbundling ("FOU"), ARERA approved[7] the Integrated Text of Functional Unbundling ("TIUF"), implementing Legislative Decree 93/2011("TEP Decree"), and the Third Electricity and Gas Directives. The TEP Decree introduced changes in respect of previous applicable rules, including, among other things, a new definition of a vertically integrated company operating in the electricity and gas sectors.

Similar to other EU Member States, under European regulation on the governance of the Energy Union and climate action, Italy has adopted its National Integrated Plan on Energy and Climate (*Piano Nazionale Integrato Energia e Clima*) ("PNIEC") to the European Commission ("Commission"). The PNIEC sets out: (i) the Italian contribution to the European targets for 2030 on energy efficiency and renewable sources and (ii) the Government's objectives in terms of energy security, a single energy market and competitiveness.

In particular, the main targets of the Italian PNIEC are:

- a quota of energy from RES, with a final gross energy consumption of 30%, in line with the targets set by the EU for Italy;
- a quota of energy from RES, with a final gross energy consumption in the transport sector of 22% compared to the EU target of 14%;
- a reduction in primary energy consumption, compared to the PRIMES 2007 scenario, by 43% compared to the EU target of 32.5%; and
- the reduction of greenhouse gases ("GHGs") compared to 2005, with a 33% target for all non-ETS sectors (3% higher than the EU provisions).

In the context of a low-carbon economy, the PNIEC also provides for the phasing out of coal from electricity production by 2025. In May 2019, the Council of Ministers of the European Union ("EU") formally adopted four new pieces of EU legislation, thereby completing the Clean Energy for All Europeans Package ("Clean Energy Package").[8] The Government implemented the Clean Energy Package, meeting the ambitious targets set for 2030.

Italy is implementing the European legislative package out of which: (i) the Energy Performance of Buildings Directive, which became national law in June 2020;[9] (ii) the Directive on common rules for the internal market in electricity, transposed in November 2021;[10] (iii) the Energy Efficiency Directive, which has a target to reduce primary energy consumption in the EU by at least 32.5% by 2030 compared to 2007 levels, to which all Member States must contribute (Italy has set an energy saving target of 43%).[11]

A.2 Third party access regime

Access to transmission and distribution infrastructure is subject to principles of transparency and non-discrimination; ARERA sets out the relevant tariffs and conditions for access to the grid. With respect to transmission activity, a code was drafted under the Decree of the President of the Council of Ministries of 11 May 2004, which outlines the rules for the unification of the ownership and management of the national grid on the basis of the guidelines set out by ARERA under Resolution 250/04. Any amendment to the grid code must be approved by ARERA and MASE (formerly, such a competence was attributed to MIMIT).

For distribution activities, only certain provisions have been set out by ARERA in the form of a code. Additional provisions are detailed in the distribution contract based on the relevant ARERA Resolutions.

Connection to the grid by power plants is regulated by ARERA Resolution 98/09 and Resolution 111/06. These set out the main content of the dispatching service agreement to be entered into with Terna by the holders of generation and consumption units, directly or through a third party acting as agent.

New interconnectors may benefit from an exemption from the third-party access rules, granted by MASE (formerly, such a competence was attributed to MIMIT) following a decision from ARERA, under the relevant EU rules. Various interconnectors have obtained such an exemption, the last of which is the interconnector between Italy and Austria developed by Resia Interconnector S.r.l. (owned by a consortium of energy intensive users).[12]

A.3 Market design

The activities of electricity generation, importation, wholesale of electricity, and sale to end customers, are not subject to any licence. However, Law no. 124/2017 provides that sale of electricity to end customers can only be carried out by players enrolled in a specific register (*Elenco dei soggetti abilitati alla vendita di energia elettrica ai clienti finali*). To date, this register has not been established. Instead, transmission and distribution activities are carried out on the basis of concessions.

A.4 Tariff regulation

Under Resolution 654/2015/R/EEL of 23 December 2015, ARERA defined the regulation of tariffs for transmission, distribution, and measurement of electricity services for the regulatory periods in 2016 to 2023, with effect from 1 January 2016. The regulatory period is divided into two four-year periods (NPR1: 2016-2019 and NPR 2: 2020-2023).

In late 2018, ARERA updated the tariffs for transmission, distribution, and measuring of electricity services for domestic and non-domestic customers, effective from 2019.

ARERA Resolution 568/2019/R/EEL of 27 December 2019 (as modified by Resolutions 566/2020/R/EEL of 22 December 2020 and 623/2020/R/EEL of 28 December 2021) concerning the 2020-2023 period, confirmed ARERA's gradual adoption of the totex approach, the aim of which was to introduce a new regulation scheme aimed at integrating tariff regulation, the regulation of continuity and quality of service, and support for innovation with output-based logic. ARERA have commenced the necessary consultation phase with operators and introduced (from the NPR2 period) preparatory tools for a regulatory system based on forward-looking and output-based themes. Moreover, ARERA indicates its intention to establish, from the final year of the NPR2 period, a means of recognising the total cost of expenditure towards transmission companies, and to later extend the application (from the new regulatory period) to major electricity distributors.

A.5 Market entry

As a consequence of the liberalisation process started by the Legislative Decree 79/99, the generation, import, export, purchase, and sale of electricity is free and not subject to any licence or concession regime. The electricity market is vibrant in terms of the number of operators, mergers and acquisitions, technologies improving security and system flexibility, and RES development.

However, the construction and operation of power plants must be authorised by the relevant authorities. Depending on the size and type of power plant, authorisations or consents may be granted on a national or local level, and such consent may be subject to environmental screening or EIA. For more information on the licensing regime applicable to energy plants using renewable resources, see section F.1.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The sale of electricity is a free activity. Since the enactment of Law Decree no. 73/2007 (converted by Law no. 125/2007), all customers can freely choose their supplier.

Certain end customers used to be entitled to be served according to special economic and contractual conditions set out by ARERA, ie, the protected supply service (*servizio di maggior tutela*). Such end customers included households, as well as business consumers connected at a low voltage, with less than 50 employees and a yearly turnover not exceeding €10 million (see section A.1).

However, Law no. 124/2017 provided for the abolishment of the protected supply service. Following several postponements, the abolishment of this regime started from 1 January 2021 for business customers, and it will start from 1 January 2023 for household customers.

End customers that do not opt for the free-market regime will be supplied, for the first six months, by the same supplier as that of the protected supply service but under different economic conditions. After six months, they will be served by a last-resort service supplier selected through public tenders, without prejudice to the right to opt for the free market at any moment.

Smart metering

The installation of smart meters has been implemented under different phases. Since 2001, local distributors have installed smart meters with the aim of having more precise consumption data and thereby avoiding adjustments on billing.

On the basis of ARERA Resolution 222/2017/R/EEL, E-Distribuzione S.p.A. began its 15-year plan for installing the second generation (2G) smart metering system. The new generation smart meters will allow for constant monitoring of the relevant daily consumption and can register data on electricity withdrawn and electricity consumption every 15 minutes. The data will be available online after 24 hours.

Electric vehicles

To promote the use of electric vehicles ("EVs") and hybrid vehicles, Law Decree no. 147/2021 (Fiscal Decree 2022) refinanced (with €100 million) the Automotive Fund established in 2019 in order to provide an incentive ranging from €1,500 to €6,000 for the purchase or financial lease of vehicles with low carbon emissions, ie, with carbon dioxide ("CO_2") levels below 60g per kilometre.

The development of EVs is strictly linked to the development of recharge systems for which Law Decree no. 77/2021, converted into Law no. 108/2021, introduced simplifications for the installation of recharge stations (ie, they are considered as free activity and thus do not require a building permit), with a specific simplified procedure for those infrastructures to be located on public areas.

A.7 Cross-border interconnectors

There are currently 25 cross-border interconnection lines connecting the Italian national grid with the following neighbouring countries, some of which are operated on a merchant basis, thereby benefiting from a third-party access exemption:

- France;
- Corsica;
- Switzerland;
- Austria;
- Montenegro;
- Slovenia; and
- Greece.

Additional interconnectors are currently under construction or in a project phase on the borders with France, Switzerland, Austria, and Tunisia.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

The production, import, export and storage of mineral oils and hydrocarbons are liberalised activities in the national territory, as is the distribution of fuels.[13]

Exploration and production ("E&P") activities are subject to a licence regime managed by MIMIT. The installation of storage facilities and fuel distribution stations is subject to the authorisations being issued by, respectively, the relevant region or municipality.[14]

There are 673 productive wells in Italy, of which 514 are gas wells, 159 oil wells, 437 are onshore and 236 offshore. The annual production amounts to about 4.42GS cubic metres of gas and 5.38 million metric tonnes of oil.

Regarding hydrocarbons, there are currently 63 exploration permits in issue and 172 production or cultivation concessions, the production of which is sent to 71 gas and 15 oil treatment and collection plants.

Key market players

The main oil producers are Eni S.p.A., Enel S.p.A. Shell Italia E&P S.p.A., Edison S.p.A., Adriatica Idrocarburi S.p.A., Gas Plus Italiana S.p.A., Eni Mediterranea Idrocarburi S.p.A., and Padana Energia S.p.A. Oil distribution operators manage a network of about 20,800 service stations. Operators are owned by integrated oil companies (50%), non-integrated entities displaying an integrated oil company brand (32%) or non-integrated entities that display their own brand (*pompe bianche*) (18%).

Regulatory authorities

In addition to MIMIT and the MASE,[15] the Regions and the Municipalities oversee the issuing of the relevant licences, authorisations and permits relating to the oil market, and also managing any environmental aspects.

Local departments of the National Mining Office for Hydrocarbons and Geothermy (*Ufficio Nazionale Minerario per gli Idrocarburi e le Georisorse*) ("UNMIG") supervise proper execution of works and compliance with safety standards in the workplace across the entire sector of oil and hydrocarbons exploration, development, production, and natural gas storage.

GME, implementing Legislative Decree 249/2012, organises and manages a Market Platform for Mineral Oil Logistics Services (P-LOGISTICS), as well as the data collection on storage capacity and transit of mineral oils. In order to foster competition in the sector, Legislative Decree 249/2012 also foresees that GME establishes, organises and manages a platform for the wholesale exchange of liquefied petroleum products for transport purposes.

Legal framework

Mineral resources in Italy, such as hydrocarbons, belong to the State under Article 826 of the Italian Civil Code. Therefore, E&P activities are subject to the obtainment of a licence issued by MIMIT. Private companies that produce oils and hydrocarbons, under the relevant licence must pay concession fees (based on the area covered by the licence) and royalties (based on the production amounts) to the State, the Regions, or the affected Municipality.

The UNMIG is entrusted with the application of regulations and implementation of assessment procedures for the granting of E&P licences, as well as inspection and control procedures concerning the technical and administrative management of each E&P concession. These tasks concern both onshore and marine areas.

The Minimum Stocks of Crude Oil and/or Petroleum Products Directive was implemented into national law by Legislative Decree 249/2012, which establishes an obligation to maintain a minimum level of crude oil stocks and/or petroleum products and ensure a high level of security through reliable and transparent mechanisms.

In respect of fuel distribution, the liberalisation process started with Legislative Decree 32/1998, which outlined that the installation of new distribution plants is subject to an authorisation to be issued by the relevant Municipality. Subsequently, Law No. 239/2004 completed the liberalisation in the production, import, export, and storage of mineral oils in Italy.

Gas

Nature of the market

There are import, exploration and exploitation, liquefied natural gas ("LNG"), storage, transport, and distribution infrastructures in Italy. Italy is a net importer of gas. In 2020, Italy imported 66.4 cubic gigametres of gas, net of export, from Russia, Algeria, Libya, Qatar, and other countries, while the national production amounted to 4.051 million cubic metres.

Key market players

Regarding the transportation infrastructure sector, Snam Rete Gas S.p.A. owns more than 90% of the national network; the second largest operator in the sector being Società Gasdotti Italia S.p.A.. Seven other operators own minor parts of the regional network.

The distribution market is highly fragmented with several operators carrying out the activities on the basis of concessions.

Regarding storage, the main player is Stogit S.p.A. (part of the Snam Group) while Edison Stoccaggio S.p.A. and Italgas Storage S.p.A. operate the remaining storage fields. The Snam Group also operates an LNG regasification terminal through GLN Italia S.p.A. and has a 49.07% interest in OLT Offshore LNG Toscana S.p.A. ("OLT"). The third regasification terminal in Italy is operated by Adriadic LNG (Terminale GNL Adriatico S.r.l.).

On the import side, the three largest players in 2020 were Eni S.p.A. (47%), Edison S.p.A. (17%) and Enel Trade S.p.A. (11%). Eni is also the main player in the wholesale and retail sectors.

Regulatory authorities

ARERA is the NRA for gas (for more on ARERA, see section A.1).

Until the reorganisation of MIMIT and MASE those two ministries shared responsibilities for the licensing, permitting and environmental issues in the oil & gas sector while most of them are currently attributed to MASE.

The Italian Competition Authority (*Autorità Garante della Concorrenza e del Mercato*) ("AGCM") is responsible for monitoring and ensuring fair competition and consumer protection in the energy sector.

Legal framework

The main legislation regulating the gas sector is Legislative Decree 164/2000, implementing the First Energy Package Directive. In order to promote competition in the market, the Decree sets out a prohibition to hold market shares higher than 50%.

According to the applicable regulatory framework, exploration activity is subject to a licence issued by MASE and the production activity can be carried out based on a 20-year concession issued by MASE. Similarly, gas transmission and distribution are subject to concessions.

Storage activities are carried out as per a 30-year concession which may be extended only once for no more than ten years. All concessions granted in Italy require depleted exploitation fields to be converted into storage fields.

Under Legislative Decree 93/2011, imports longer than one year are subject to an authorisation from MASE while short-term imports require the filing of a communication to MASE.

Producers and long-term importers are subject to gas release obligations to be performed in accordance with the provisions of Law Decree no. 7/07. These operators must offer a certain percentage of the gas imported or produced on a platform managed by GME.

Sale to end customers and LNG regasification activities are subject to an authorisation by MASE.

Implementation of EU gas directives

The Third Energy Package was implemented by Legislative Decree 93/11. Initially the Legislative Decree adopted the independent transmission operator ("ITO") model. In 2012, Law Decree no. 1/2012, converted into Law no. 27/2012, imposed the FOU regime on Snam Rete Gas.

Following various divestitures by Eni in Snam (the sole shareholder of Snam Rete Gas) and a particular governance adopted by Cassa Depositi e Prestiti (owning interests both in Snam and Eni), ARERA certified Snam Rete Gas as TSO under the ownership unbundling regime with Resolution 515 of 14 November 2013. additionally, the other main TSO, Società Gasdotti Italia S.p.A., is certified under an ownership unbundling model.

B.2 Third party access regime to gas transportation networks

Access to gas transportation networks is subject to the principles of transparency and non-discrimination. ARERA sets out relevant tariffs and conditions for access to the grid and approves the grid code of TSOs.

New interconnectors may benefit from an exemption from third party access rules, granted by MIMIT following a decision from ARERA, under the relevant EU rules. The Trans Adriatic Pipeline ("TAP") project, ie, the interconnector between Italy, Albania and Greece transporting gas from Azerbaijan, has obtained a third-party access exemption for the entire capacity for 20 years.

B.3 LNG terminals and storage facilities

Three re-gasification terminals are currently in operation: the Panigaglia terminal, managed by GNL Italia (Snam Group); the offshore Adriatic LNG terminal in Porto Viro, near Rovigo; and the Livorno terminal owned by OLT.

Access to LNG terminals is subject to the principles of transparency and non-discrimination. The conditions and tariffs for such access is established by ARERA. New LNG infrastructures may benefit from an exemption from the third-party access rules. The Adriatic LNG terminal is operated under a third-party access exemption regime for 80% of its capacity. While OLT initially received an exemption, this was renounced at a later stage.

In addition to the LNG regasification terminals, several small-scale LNG projects are under development in Italy (especially in Sardinia) which are also benefitting from the International Maritime Organisation 2020 ("IMO 2020") obligations, given their use for bunkering. Under the IMO 2020 obligations, as of 1 January 2020, the marine sector must reduce sulphur emissions by over 80% by switching to lower sulphur fuels.

Provisions that apply to access similarly apply to storage. None of the currently operating storage facilities benefit from a third-party access exemption.

With the aim of supporting the recovery and decarbonisation of productive activities in Sardinia, the Government enacted two simplification decrees in 2020 and in 2021 (Law Decree no. 76/2020, converted into Law no. 120/2020, and Law Decree no. 77/2021, converted into Law no. 108/2021) by which the infrastructures for LNG transport and regasification that is necessary for the supply of natural gas by ships from Snam's regasification terminals to the regasification terminals to be built in Sardinia, will be considered as part of the national transport grid (the so-called 'virtual pipeline'). This is also for tariff purposes.

In November 2021, the Government published a draft of ministerial decree containing a list of the relevant activities and infrastructures for the purposes indicated above. The decree has not been enacted yet.

B.4 Tariff regulation

ARERA is responsible for the approval of the tariffs structure in relation to transportation, distribution, storage, and LNG regasification.

The structure of the tariffs is applicable for three years but adjustments to specific fees are made on a periodic basis.

ARERA approved the tariff structure with respect to:

- transportation, with Resolution 575/2017/R/gas for the years 2018 and 2019;
- distribution, with Resolution 573/2013/R/gas for the period 2014 to 2019;
- storage, with Resolution 419/2019/R/gas for the period 2020 to 2025; and
- re-gasification, with Resolution 474/2019/R/gas, for the years 2020 and 2023.

B.5 Market entry

Under Legislative Decree 164/2000, the sale of natural gas is free and not subject to any licence or concession regime. Imports are subject to specific authorisations.

Natural gas cultivation, distribution, transport, and storage businesses are, however, subject to the concession regime.

With specific reference to the distribution of natural gas, Italy[16] is divided into 177 areas with an optimal size for gas distribution, economies of scale and cost reduction (*Ambito Territorialiale Minimo*) ("ATEM"), as identified under Ministerial Decree 19 January 2011. Under Legislative Decree 164/2000, the natural gas distribution service is subject to the obtainment of a concession awarded by a tender procedure and assigned for a maximum period of 12 years (for each ATEM). All the concessions awarded after the entry into force of Legislative Decree 164/2000 on 21 June 2000, continue until the original expiry date for a maximum 12 years from the date of the assignment. These concessions continue until their original expiry date, which may fall after the awarding of the ATEM tender procedures. Once awarded the new ATEM concessions, the incoming concessionaires will take over the gas distribution service only at the relevant original expiry date.

Concessions awarded before and already in force at the date of 21 June 2000 continue until their earlier natural expiry date or 31 December 2012, provided that they have been awarded by tender procedure. Concessions awarded before 21 June 2000 without tender procedure continue in full force until 31 December 2007.[17]

When a concession expires, the outgoing concessionaire must carry out the gas distribution service until the future incoming concessionaire is awarded by a new concession. Once assigned the new concession, the incoming concessionaire must pay to the outgoing concessionaire the reimbursement value of all plants and assets transferred by the latter for the purpose of the gas distribution service operation.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Since 2003, all customers can freely choose their electricity supplier. Currently, household customers are entitled to be served according to special economic and contractual conditions set out by ARERA, ie, the protected supply service (*servizio di tutela*); however, Law no. 124/2017 provided for the abolishment of the protected supply service. Following several postponements, the abolishment of this regime will start on 1 January 2023.

For the first six months, end customers that do not opt for the free-market regime will be supplied by the same supplier as that of the protected supply service but under different economic conditions. After six months, they will be served by a last-resort service supplier selected through public tenders, without prejudice to the right to opt for the free market at any moment.

Smart metering

Under ARERA Resolution 669/2018, distributors with over 200,000 customers must achieve 85% installation of smart meters within 2020; the same percentage shall be achieved within 2021 by distributors with 100,000-200,000 customers and within 2023 by distributors with 50,000-100,000.

B.7 Cross-border interconnectors

Five interconnectors are currently in operation in Italy, including the TAP, which connects Italy and Greece via Albania. The TAP project benefits from a third-party access exemption. The ITGI Poseidon pipeline connecting Italy and Greece has also obtained a third-party access exemption, although this only operates within the Italian section of the pipeline.

C. Energy trading

C.1 Electricity trading

Trading of electricity can occur OTC or on the GME exchange, where GME acts as central counterparty.

OTC deals must be registered at a platform managed by GME (*Piattaforma Conti Energia*) ("PCE") to be executed. In order to have access to this platform, certain contracts must be signed with GME.

With respect to the trading on the GME exchange, GME manages the Italian Power Exchange (IPEX), which is divided into different segments, in particular:

- the MTE forward physical market;
- the MPEG market for the trading of daily products, with continuous trading mode;
- the MGP day-ahead auction market;
- the MI intraday auction market, which is based on five sessions; and
- the Nomination Platform (PN), to allow the programming on the offer points of the commercial positions, resulting from the negotiations concluded in the MI-XBID session.

Under ARERA Resolution 45/2015/R/EEL and Resolution 514/2020, on the Italian-Slovenian, Italian-French, Italian-Greek and Italian-Austrian border, interconnection capacities are allocated daily through the market coupling mechanism.

While in all the above markets. GME is the central counterparty, on MSD, the ancillary services market, GME only operates the platform where Terna buys the necessary resources for balancing the system.

All the markets above are regulated and managed by GME in accordance with specific legal provisions.

C.2 Gas trading

Trading of gas can occur OTC or on the exchange, where GME acts as central counterparty.

OTC deals may occur through registration on the PSV (*punto di scambio virtuale*), the Italian virtual hub managed by Snam Rete Gas.

GME organises and manages the natural gas market ("MGAS") which is divided into five different segments:

- the MT-Gas forward physical market;
- the MGP-GAS day-ahead gas market;
- the MI-GAS intraday gas market;
- the MPL locational products market, whose participation is reserved to certain qualified operators and the sessions are held only upon request of Snam Rete Gas for balancing purposes; and
- the MGS regulated market for the trading of gas stored.

GME also manages the P-GAS where operators (ie, long-term importers, gas producers and investors participating in virtual gas storage under Legislative Decree 130/2010) can fulfil gas release obligations.

D. Nuclear energy

After the Chernobyl disaster, all operating Italian nuclear power plants were decommissioned by law following a subsequent referendum in 1987.

More than 20 years later, by Law no. 99/2009, the Italian Parliament encouraged a new national nuclear power strategy to be implemented by the Government.

After the Fukushima nuclear accident, the Government outlined a one-year moratorium on any initiative to restart nuclear power plants. On 13 June 2011, a second referendum on nuclear energy, among other things, led to a repeal of provisions concerning the development of new nuclear power plants in Italy, which halted any move towards an Italian nuclear power policy.

The programme for decommissioning previously operating plants, decontaminating nuclear sites, and managing radioactive waste is still ongoing. This programme is managed by the State company Sogin S.p.A., established in 1999, and is financed by the CSEA. For more details on the CSEA, see section A.1).

E. Upstream

For information regarding Italy's upstream regime, see section B.1.

F. Renewable energy

F.1 Renewable energy

There are several mechanisms that support renewable electricity generation in Italy. All are subject to the execution of a contract regulated under the Italian Civil Code to be entered into with the GSE. The main mechanisms currently in force are:

- Conto Energia (FiT scheme), which is the incentive dedicated to photovoltaic ("PV") and solar thermal plants, granted by the GSE under the ministerial decrees enacted by the Government between 2005 and 2012 (Conti Energia – Energy Accounts). The scheme consists of a fixed incentive tariff paid for a 20-year period on the net electricity generated, additional to the revenues resulting from the sale of energy. Starting from 2012, access to the incentive has been subject to competitive procedures. This scheme does not apply for new plants, although it continues to be effective for existing incentivised plants until the termination of the remaining incentive period, and it has been subsequently replaced with the Decree of 4 July 2019 ("RES-1 Decree");
- Tariffa GRIN (FiT scheme), which is the incentive regime dedicated to RES-sourced energy other than PV and solar thermal. The incentive is granted by the GSE and replaced the previous 'green certificates' regime from 2016 until the residual incentive period. Unlike the green certificate's regime, access to the incentive was subject to competitive procedures. This scheme does not apply for new plants, although it continues to be effective for existing incentivised plants until the termination of the remaining incentive period. For onshore wind, hydro and sewage treatment and landfill gas plants, it has been recently replaced with the RES-1 Decree;
- RES-1 Decree, which is the incentive granted by the GSE to the main RES, including PV, and consisting of a fixed incentive tariff paid for the entire operating life of the relevant plant. Access to the incentives is subject to competitive procedures. The RES-1 regime expired on January 2022; however, it has been extraordinarily prolonged by Law Decree 199/2021 until a new incentive scheme for RES will be adopted and limited to the quota of capacity not assigned;
- RES-1 Decree does not apply to offshore windfarms, biogas plants, biomass and bioliquid plants, oceanic source, and thermodynamic solar plants. For new plants fuelled by these sources, and which were previously incentivised by the green certificates and *tariffa* GRIN, a new incentive scheme is expected (so called RES-2 decree);

- All-inclusive tariff (*tariffa omnicomprensiva*), which is a fixed tariff remunerating the electricity injected into the grid, by granting both the incentive component and the value for the net electricity generation. The incentive is granted exclusively to small RES plants with a nominal capacity up to 1MW;
- Simplified sale and purchase regime (*ritiro dedicato*), which is a simplified sale agreement to be entered into with GSE, based on the standard contract available on its website;
- Spot Exchange (*scambio sul posto*), which enables economic compensation between the value of the electricity fed into the grid and the value of electricity consumed on site. Access to this regime is granted to (i) plants that entered into operation before 31 December 2014, which are powered by renewable sources or high-efficiency cogeneration having maximum nominal capacity of 200kW, or (ii) plants entered into operation on or after 1 January 2015 having maximum nominal capacity up to 500kW and powered by RES. The Spot exchange mechanism was recently repealed by Legislative Decree no. 199/2021;
- Local energy communities and collective self-consumption systems, which grant incentives to local systems of production and consumption. The relevant current regulatory framework is set out by Article 42 of Law Decree 30 December 2019, no. 162, converted into Law 28 February 2020, no. 8, which envisages two different configurations:
  a. renewable energy communities, in which natural persons, SMEs, territorial authorities or local authorities, including municipal administrations, owners of connection points located on low-voltage electricity grids subtended by the same medium or low-voltage transformer substation (same secondary substation) may participate; and
  b. collective self-consumption from renewable sources, which can be activated within the same building and condominium.

The production plants that can be included in these configurations must be powered by RES, enter in operation by 15 December 2021 and, in this transitional phase, have a maximum capacity of 200kW. Plants must be newly built or repowered (in this case only the section subject to repowering is taken into account); PV plants may only be built with new components. PV plants ground-mounted on agricultural areas are not eligible for the incentives.

The incentives amount to:

- €110/MWh for local energy communities; and
- €100/MWh for collective self-consumption systems.

New ministerial decrees are expected to be enacted under Legislative Decree no. 199/2021 in order to provide a new regime of incentives for such consumption schemes. The capacity of the plants that may benefit from the tariff has been increased to 1MW.

Controversial issues

In the PNIEC, PV and wind energy were the main sources that contributed to the increase of energy generation from RES. However, to reach the 2030 PNIEC targets, simplification, along with speeding up, of authorisation procedures is one of the crucial action points. It is estimated that the PNIEC targets will require the authorisation of RES plants construction and/or repowering and/or revamping for an overall nominal capacity of about 4.5GW per year for the next ten years. It is difficult to imagine reaching PNIEC's objectives without a clear commitment on behalf of regional institutions.

The complexity in developing new RES projects is the major barrier in market development. Different Regions are going in different directions with regards to the authorisation procedure, especially concerning the terms on which to conclude procedures. The central role of the Regions is particularly evident in EIA and building authorisation procedures. Their political role also takes particular importance to date since the Regions (and autonomous Provinces) are bound to reach national RES consumption objectives. Even considering new and more ambitious objectives for 2030, it would be crucial for each region to host productive RES projects to fulfil the proposed consumption target. The identification of 'suitable areas' (as defined in the PNIEC) for the development of RES projects is also an important aspect for consideration. The use of the wording 'suitable areas' in the PNIEC implies a requirement for administrations to exclude RES installations in areas that do not fall under such classification.

Public consent also has a decisive impact in implementing RES projects. The formation of interests contrary to investment projects can create hostile conditions and could delay or stop authorisation procedures. In the absence of a clear legislative framework, companies should consider putting forward initiatives aimed at raising public awareness, and show the different market players' positions, interests and needs related to the implementation of RES projects. At the same time, companies could accept any specific requests coming from the territory (or part of it).

However, in order to guarantee the full integration of renewable energy in the market and the achievement of the PNIEC targets, a number of simplification measures have been implemented by the Government through the so-called 'simplification decrees',[18] ensuring shorter and more certain bureaucratic processes.

F.2 Renewable pre-qualifications

Italy does not currently have any renewable pre-qualifications.

F.3 Biofuel

Law no. 81/2006 promoting the use of biofuel instead of diesel or petrol in transport requires the distributors of petrol, diesel, and fossil fuels to distribute a minimum quota of biofuel (obligation quota). This quota is set at 10% from 2021 onwards.

Legislative Decree 97/2011 implemented the Biofuel Directive, providing for, among other things, the definition of a biofuel classification system and sustainability criteria.

The MITE – now reorganised and redenominated MASE – has enacted the Decree 15 September 2022 ("New Biomethane Decree"). This was published in the Official Gazette of the Italian Republic No. 251 of 26 October 2022 and entered into force on 27 October 2022. It sets out a new public subsidies scheme for production of biomethane under component 2 of the mission 2 of the National Recovery and Resilience Plan, for an overall amount of about 1.7 billion.

It aims at promoting the production of biomethane injected into the natural gas grid and produced in compliance with the sustainability requirements of Directive 2018/2001/EU (so-called "RED II") by granting (i) a capital contribution amounting to 40% of eligible expenditure, and (ii) a specific incentive tariff.

The New Biomethane Decree implements Article 11 of Legislative Decree no. 199/2021, which defines general criteria for granting, through public competitive procedures, non-repayable contributions on eligible expenditure incurred for investment, for efficiency interventions, partial or total revamping of existing biogas plants, for new biomethane production plants.

The previous incentive regime, set out by Ministerial Decree 2 March 20183 ("DM 2018"), originally applicable to plants entering in operation by 31 December 2022, has been recently extended to plants that will enter in operation by 31 December 2023.

G. Climate change and sustainability

G.1 Climate change initiatives

The 2013 EU Strategy on adaptation to climate change led EU Member States to adopt a national Climate Change Strategy. In Italy the following initiatives took place:

- National strategy on adaptation to climate change, approved by Ministerial Decree 16 June 2015;
- Strategic Positioning Document: Towards a circular economy model for Italy (*Verso un modello di economia circolare per l'Italia -Documento di inquadramento e posizionamento strategico*), adopted on 7 December 2017 by MIMIT and MASE. The document, in addition to providing for a general overview of the circular economy, aims to define Italy's strategic positioning on the matter, in compliance with the commitments set out under the Paris Agreement on climate change and the 2030 UN Agenda for Sustainable Development;
- National Strategy for Sustainable Development (*Strategia Nazionale per lo Sviluppo Sostenibile*) ("SNSvS"), approved by CIPE[19] on 22 December 2017, draws a vision of a future, and of development, focused on sustainability as a shared value. A position that is essential in tackling the global challenges facing the country. The SNSvS represents the first step towards implementing the principles and objectives of the 2030 Agenda for Sustainable Development;
- Sustainable Mobility Roadmap (*Elementi per una Roadmap della Mobilità Sostenibile*), developed in 2017 with contributions from the MASE, MIMIT, Ministry for Infrastructure and Transport, research institutions, operators, and consumer and trade associations;
- Framework agreement entered into in 2017 with the Regions and local entities for the development of charging grids (*Accordo di programma con le Regioni e gli Enti locali per la realizzazione di reti di ricarica dei veicoli elettrici*), executed in the context of the National Plan for charging EVs (*Piano Nazionale Infrastrutturale per la Ricarica dei veicoli alimentati ad energia elettrica*) ("PNIRE"), approved in 2012 and updated in 2016;
- Action plan for environmental sustainability of consumption in the public administration (*Piano d'azione per la sostenibilità ambientale dei consumi nel settore della Pubblica Amministrazione*) ("PAN GPP"); and
- Action Plan on sustainable production and consumption (*Piano d'azione in materia di produzione e consumo sostenibile*) ("PAN SCP"). This is part of the framework of international and national policies and strategies on the circular economy, efficient use of resources and climate protection, implementing the Action Plan Report on Sustainable Production and Consumption and on Sustainable Industrial Policy COM (2008)/397 and the 2030 Agenda of the United Nations.

The first legal action aimed at imposing the implementation of ecological policies on the State, known as the Universal Judgment campaign (*Giudizio Universale*) was brought before the Court of Rome in 2021.

The objective of the Universal Judgment campaign is to bring the State to court over alleged breaches of human rights in relation to climate change. The claim represents a new area for Italian case law, though not for European or other EU Member States where such actions have already been lodged. It can therefore be said that the global movement seeking environmental justice has now also begun in Italy.

The campaign is composed of environmental associations, local committees and individuals concerned about climate change. The central belief of the campaign is that there needs to be institutional and political action in relation to climate change, and it seems inspired by other worldwide movements. In particular, the campaign draws inspiration from legal actions already brought (for instance) in the Netherlands by the Urgenda Foundation.

The claim replicates the Dutch action, requesting that Italy adheres to scientific recommendations to restrict global warming below the critical +1.5°C in comparison with the pre-industrial period. Italy, according to the campaign, is particularly vulnerable to climate change due to its geographical position and territorial composition, and it is in this light that the campaign will be asking the Court to recognise the gravity of the situation and ask the State to take affirmative action.

G.2 Emission trading

In accordance with the New EU ETS Directive, in the third regulatory period (2013 to 2020) Italy will participate in the European central auction platform managed by the European Energy Exchange AG ("EEX"). In this context, GSE has been appointed by the Government as the national auctioneer for the Italian emission quotas. The provisions of the New EU ETS Directive are implemented through the ETS Decree, with little modification. The ETS Decree also takes the Emissions Allowances Decision, concerning the rules for free allocation of emission allowances, into account.

On 25 July 2013, the National Committee on the Management of the EU ETS Directive adopted Resolution 16/2013 regulating the excluded plants regime under Article 36 of the ETS Decree.

In July 2016, the Commission's Environment and Productive Activities of the Chamber of Deputies approved the Energy Union Package. This package was promoted by the Commission, and it is aimed at encouraging European integration in the energy sector. Furthermore, with Ministerial Decree 10 November 2017, the Government approved the new National Energy Strategy for 2030 ("SEN 2030"), which is in line with the objectives set out by the Energy Union Package and climate policy. Under the SEN 2030, the Government undertakes to promote reform of the ETS system (also with a harmonised carbon tax or price floor) for the acceleration of the decarbonisation process, with appropriate measures to safeguard companies exposed to international competition as well as to fight carbon leakage.

In January 2021, the MASE, published Italy's long-term strategy on reducing GHG emissions.

The strategy takes as a basis the PNIEC, which shows the path to 2030, prolonging virtuous energy-environmental trends to 2050. It identifies the types of levers that can be activated to achieve climate neutrality by 2050: (i) a strong reduction in energy demand, linked in particular to a drop in consumption for private mobility and consumption in the civil sector; (ii) a radical change in the energy mix in favour of RES, combined with a profound electrification of end uses and the production of hydrogen; and (iii) an increase in the absorption guaranteed by forest areas (including forest soils) obtained through sustainable management, the restoration of degraded areas and reforestation.

G.3 Carbon pricing

Italy does not currently have a carbon pricing strategy.

G.4 Capacity markets

Italy introduced the capacity market, which is a mechanism by which Terna procures capacity through long-term procurement contracts awarded through competitive bidding.

Operators of new production units (programmable and non-programmable), both authorised and non-authorised, can participate in the tender organised by Terna. The selected capacity provider, as a result of the tender process must:

- offer capacity on the energy and services markets;
- have the right to receive an annual fixed premium from Terna; and
- repay Terna the difference, if positive, between the price of the electricity realised on the energy and services markets and the strike price defined by ARERA.

Capacity market units (demand-side response) and foreign resources with specific obligations and rights may also bid.

2022-2023 delivery period

The procedure for the procurement of capacity for the 2022-2023 delivery period was outlined by the Ministerial Decree 28 June 2019 and related implementing acts published by Terna.

The auctions took place at the end of 2019 and capacity was allocated to the selected operators.

Pending litigation

A litigation is pending before the Regional Administrative Court of Milan concerning the Italian regulation of the capacity market and the rankings of the auctions published by Terna for the 2022-2023 delivery period.

The claims, brought by operators and the major association of solar operators (*Associazione Italia Solare*), are grounded on the following main reasons: (i) the Decree of Ministry of Economic Development of 28 June 2019 has been issued without the required consultation of the relevant market players; (ii) certain operators have been allowed to participate in the auction launched by Terna in November 2019, albeit they had not been authorised yet; and (iii) capacity market regime leads to anti-competitive results.

Legal proceedings have been suspended by the Regional Administrative Court of Milan in light of the litigation pending before the Court of the European Union against the decision no. C (2019) 4509 of 14 June 2019 of the EU Commission by which the Italian capacity market regulation has been considered to be compliant with the EU State aid legislation.

2024-2025 delivery period

The procedure for the procurement of capacity for the 2024-2025 delivery period has been approved by the Ministerial Decree 28 October 2021 and related implementing acts published by Terna.

The auction for the 2024 delivery period will occur on 21 February 2022. Interested operators sent the request to participate within 31 December 2021. On 22 February 2022, Terna published the auction results, according to which 41.5GW of capacity has been awarded (34.1GW of existing capacity, 1.5GW of new authorised capacity, 2.2GW new unauthorised capacity and 3.6GW virtual foreign capacity).

The auction for 2025 delivery period is currently suspended.

H. Energy transition

H.1 Overview

The Italian energy transition is widely affected by multi-level dynamics; however, the impact of these dynamics is ambiguous. The State's direct intervention in industrial policy and centralised models had for a long time been considered key to achieving economic development and international competitiveness. Over the years and in the era of the liberalisation of the energy sector, centralised frameworks have shown their flaws and are now no longer considered to be able to meet the challenges of the energy transition. The decentralisation of energy policymaking, which began in the late 1990s, coupled with generous incentive schemes, has played a key-role in fostering the growth of renewables. Decentralisation has favoured bottom-up experimentations as well the activation of mutually reinforcing dynamics that have increased the scope of the Italian energy transition. At the same time, the rearrangement of competences over energy policymaking (especially after the 2001 constitutional reform that included energy among those matters of competitive competence of both the State and regions) made the Italian renewable energy's authorisation procedure more complex. Conflicts and legal disputes driven by different strategic and economic interests among regions, local governments and the central Government on energy matters provoked delayed decisions. In particular, the length of the procedures for the localisation and authorisation of renewable energy plants represents an issue that could provoke a standstill of the overall Italian energy transition strategy. Recent legislation aims to minimise this.

The Government recently regained a central role in (i) simplifying the authorisation proceeding of RES plants; (ii) facilitating the allocation of the Italian National Recovery and Resilience Plan fund ("PNRR");[20] (iii) implementing the hydrogen strategy and (iii) developing the e-mobility infrastructures.

H.2 Renewable fuels

Hydrogen

Upon the release of the Hydrogen Strategy by the European Commission in 2020, the sustainable production of hydrogen has become an investment priority within the Next Generation Europe plan. Accordingly, Italy set a PNRR, in which €3.2 billion is allocated for the research, testing, production and use of hydrogen.

The Government is giving hydrogen a central role in its plans for an ecologic transition and has set ambitious targets for the development and application of this energy sector by 2030. The MASE has recently launched public notices to allocate PNRR funds for hydrogen research and development projects.

Eligible proposals must concern green hydrogen production; innovative storage and transport technologies; fuel cells for stationary or mobility applications; and intelligent systems for managing hydrogen-based infrastructures. Funding ranges from a minimum of €2 million to a maximum of €4 million. Projects submitted by public entities will be 100% funded, while private ones will be funded from 25 to 80% depending on the type of project and size of the company.

Ammonia

There is currently no specific ammonia regime in Italy.

H.3 Carbon capture and storage

Legislative Decree 14 September 2011, no. 162 ("CCS Decree") introduced a specific regulation on carbon capture and storage ("CCS") activities in Italy, which were previously regulated by the CO_2 Emission Regulation.

Under the CCS Decree, MIMIT must select the areas upon which CCS infrastructure may be installed. CCS activity may be operated subject to the consent of MIMIT and MASE, and with the support of a dedicated technical committee. The CCS Decree also provides for several technical requirements to be met, directions to be complied with by relevant operators, and an information system (based on a register) managed by the dedicated technical committee.

Both the low price of CO_2 and the challenges of social acceptance have strongly reduced the development of CCS. Therefore, it is difficult to imagine CCS having a significant impact on Italy's 2030 energy target.

H.4 Oil and gas platform electrification

Platform electrification is essential for cutting oil and gas sector production emissions in the near term, reducing the carbon footprint of the oil and gas sector, and extending the operating life of existing assets. Instead of using fossil fuels to run platforms, power can be sourced from onshore substations, offshore wind farms, or imported from neighbouring countries (or a combination of these). However, there are no specific public funds solely granted to platform electrification projects.

H.5 Industrial hubs

The PNRR targets the gradual decarbonisation of industry and aims at developing technological and industrial leadership in the main transition sectors (PV systems, turbines, hydrolysers and fuel cells batteries) that are internationally competitive and at reducing the dependence on imported technologies, creating jobs and growth.

In the context of the specific missions targeted, the PNRR also envisages the creation of hydrogen hubs, plastic hubs, and textile hubs.

H.6 Smart cities

The Smart City Index 2021 commended Trento, Turin, and Bologna for being the most developed Italian cities from an infrastructural point of view.

In Italy, Milan has promoted several innovative and technological strategies, awarding itself for several years the title of the smartest, most inclusive, and liveable city in Italy; capable of adapting to continuous social and technological changes.

Compared to the past, smart city projects currently show an increased awareness of the importance of smart cities. Nevertheless, smart city applications account for under 8% on the internet of things (IoT) market. However, the number of smart city projects is increasing compared to previous years, with more stable and innovative initiatives.

I. Environmental, social and governance (ESG)

ESG issues have risen up on the agendas of investors, governments and the global and Italian general public. ESG has become a driver for transactions, in the form of the disposals of risky assets (eg, fossil fuels) and the acquisition of sustainable assets or assets that will help a company achieve its ESG goals (eg, renewables, recycling, waste management, tech and aquaculture). At the same time, ESG factors are receiving more attention in due diligence and deal terms as their materiality increases.

There is also greater regulatory focus on ESG, reflected in the introduction of reporting requirements across the globe and moves in Italy to impose new corporate governance and risk management obligations on companies relating to ESG.

While reporting requirements have to date largely been targeted at listed companies, they are expected to be extended to large private companies. In Italy, the focus on ESG is also strengthened by the fact that on 22 February 2022, Articles 9 and 41 of the Italian Constitution were amended to include the protection of the environment as a fundamental principle. Article 9 currently provides a duty on the State to ''protect the environment, biodiversity and ecosystems, also in the interest of 'future generations'' and Article 41 states that the economic initiative must be carried out 'without damaging the environment'.

Endnotes

1. Energy efficiency certificates and guarantee of origins.
2. Following approval of the CACM Directive, GME was designated the Nominated Electricity Market Operator ("NEMO") for the day-ahead and intraday markets in Italy.
3. In particular, it is responsible for tariff regulation, quality of service standards, promoting environmental protection and efficient use of energy, protecting consumers' interests, providing specialised opinions, recommendations and reports to the national legislative and executive bodies, etc. Over the years, ARERA has been entrusted with additional regulatory powers, among other things, in the following sectors: the integrated water services sector (Law no. 214/2011); the district heating and cooling sector (Legislative Decree 102/2014); and the waste sector (Law 205/2017).
4. Under Resolution 481/2017/R/EEL of 28 June 2017 and Resolution 922/2017/R/EEL of 27 December 2017, starting from 1 January 2018 the general system charges are split into: (i) general charges related to the maintenance of renewable energy and cogeneration, ie ASOS; and (ii) remaining general charges, ie ARIM. The ASOS component of the tariff is applied differently depending on whether a user is an energy intensive user and, if so, depending on its facility class (*classe di agevolazione*). ARIM charges are applied irrespective of the facility class. For non-domestic clients, from 1 January 2018, a new tripartite tariff structure has been applied. This consists of (i) one part in c€/point of withdrawal/year; (ii) one part in c€/kW/year; and (iii) one 'variable' part in c€/kW. This tripartite tariff structure is consistent with Article 3 of Legislative Decree 210/2015, as well as Decision C(2017) 2406 of the European Commission. For domestic clients, the classification of the ASOS and ARIM components had no material effects as the tariff structure for general charges has not been modified substantially.
5. See Legislative Decree 115/08, Legislative Decree 56/10, Law no. 99/09 and Legislative Decree 93/11.
6. See Law no. 99/09, Legal Decree 91/14, Law no. 21/16 and Law no. 19/17.
7. Resolution 296/2015/R/com.
8. A new Electricity Market Regulation and Electricity Market Directive, as well as Regulations on Risk Preparedness and on the Agency for the Cooperation of Energy Regulators.
9. Legislative Decree 10 June 2020, No. 48.
10. Legislative decree 8 November 2021, No. 210.
11. Legislative Decree 14 July 2020, No. 73.
12. In September 2019, an exemption was granted to Monita S.r.l. with respect to an interconnector between Italy and Montenegro. Being a non-EU interconnector, the Commission has not been involved in the process.
13. See Law no. 239/2004.
14. Fuel distribution stations, previously subject to a concession regime, were ope legis converted into such authorisations in 1998. Since 2012, service station operators can purchase fuel products directly from any producer or distributor.
15. Following the implementation of the Effects of Projects on the Environment Directive by Legislative Decree 104/2017, the MASE is in charge of issuing the EIA for upstream activities. Formerly, the Regions were in charge of carrying out the EIA procedure for E&P initiatives.
16. This does not include the Sardinia Region, where gas distribution is regulated under regional law and which territory is divided in 38 Basins. However, the general rules set out under Legislative Decree 164/2000 and described below also apply to the Sardinia Region concessions.
17. In respect to these latter Concessions, ie, those awarded before 21 June 2000, without a tender procedure, the relevant Municipality was entitled to extend this term by up to six years under Article 15, paragraph 7 of Legislative Decree 164/2000.
18. See Law Decree 16 July 2020, No. 76 converted into Law 11 September 2020, No. 120 and Law Decree 31 May 2021, No. 77 converted into Law 29 July 2021.
19. Interministerial Committee for Economic Planning (*Comitato interministeriale per la programmazione economica*) is a governmental body that meets periodically to coordinate decisions on economic policy at national, EU and international level.
20. See Law Decree Law Decree 6 November 2021, No. 152 converted into Law 29 December 2021, No. 233 (so-called PNRR 1 Decree), and Law Decree 30 April 2022, No. 36 (so-called PNRR 2 Decree).

Energy law in Kazakhstan

Recent developments in the Kazakhstan energy market

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Ecology

One of the major developments in the Kazakhstan energy market is the adoption of the new Environmental Code which became effective on 1 July 2021 (the "EC").

The EC is the main piece of legislation regulating greenhouse gas ("GHG") emissions. The EC, together with subordinate acts, contains detailed procedures for distributing GHG emissions quotas among regulated installations, implementing projects aimed at reducing and absorbing GHG emissions, and GHG emissions trading.

Additionally, the EC provides several important developments relating to regulating the emission of pollutant substances. The general trend is made on promotion of 'complex environmental permits' that are based on the usage of the best available technics (as compared to 'traditional environmental permits', which are based on establishing limits for a number of pollutants). The EC also made further steps to align the concept of environmental damage with the concept used in the developing countries. New legislation further significantly strengthens administrative liability for emission of pollutants without a permit or in excess of a permit.

These developments in environmental legislation have significantly impacted the implementation of projects relating to the exploration and extraction of fossil fuels.

Renewables and power market

There have been three notable more recent developments in Kazakhstan's power market, including in the renewables sector.

In 2020, legislation on newly commissioned generating facilities with a cycling regime was adopted. Following further new legislation in 2022, the Ministry of Energy conducted two auctions, one for combined cycle gas turbine with a heat generation capacity of 240MWt, and the other for a combined cycle gas turbine of 926.5MWt capacity. If both projects are successfully completed, the two power plants would substantially increase the cycling capacity of the national energy system and allow for the balancing of more renewable energy source ("RES") facilities.

Two other developments relate to the bankability of RES projects. Firstly, in 2021 the Rules on Providing State Financial Support to the Financial Settlement Centre ("FSC") approved rules on providing state financial support to the FSC, the state-owned purchaser of electricity generated by renewable facilities. Subject to a number of conditions, in the event the FSC fails to collect sufficient funds to pay renewable energy facilities for generated electricity, the State should provide the FSC with the difference. Before that resolution, the only source of the funds to pay to renewable facilities was money collected from the notional consumers. Secondly, in September 2022, the Government adopted the amendments to the rules on calculating auction prices (which is the price the FSC pays to renewable facilities that won auctions and obtained long term power purchase agreements ("PPAs") with the FSC). According to the amendments, 100% indexation of the auction price of devaluation of the Kazakhstan Tenge against the US dollar is now available for the whole period of PPA.

Gas

Kazakhstan, on the initiative of the First President of the Republic of Kazakhstan, Nazarbayev N.A., and under the leadership of the Head of State, Tokayev K.K., successfully implemented the strategy for the long-term development of Kazakhstan (Strategy Kazakhstan – 2050: a new political course of the present state). This entails a review of the current management of the gas resources of Kazakhstan and the gas industry as a whole.

On 18 July 2022, the Government of Kazakhstan introduced a comprehensive development plan aimed at further development of Kazakhstan's gas industry in the period from 2022 to 2026. The execution process of the plan will be carried out by central and local executive bodies and overviewed by the Ministry of Energy of the Republic of Kazakhstan.

The goals are to increase the production of commercial gas from 29.4 billion cubic metres ("bcm") in 2021 to 42.1bcm by 2030. Ensuring domestic gas supply and exports requires attracting investment in new gas production and processing projects, while stimulating investments into gas projects by providing fiscal preferences and advantageous commodity gas purchase prices for subsoil users.

The development plan aims to increase the coverage of the gasified population of the Republic of Kazakhstan from 9.8 million people (53.07%) in 2021 to 13.5 million people (65%) in 2030.

Overview of the legal and regulatory framework in Kazakhstan

A. Electricity

A.1 Industry structure

Nature of the market

The electricity industry of Kazakhstan consists of the generation, transmission and supply of electricity, and other activities in the electricity sector (such as construction, commissioning, maintenance and repair of facilities).

Electricity in Kazakhstan is generated by 179 power plants of various forms of ownership. As of 1 January 2021, the total installed capacity of power plants was 23,621.6MW, with available capacity of 20,078.6MW.[1] The generation sector primarily consists of large and medium size coal stations, hydroelectric power stations, combined heat and power ("CHP") stations and gas turbine stations, owned and operated by power generating organisations ("PGOs"). Generally, PGOs sell electricity in the market; however, there are certain PGOs that produce electricity for intra-group purposes.

The transmission sector consists of the national power grid network and the regional level networks. The national power grid network connects PGOs, regional networks, wholesale customers and the power systems of neighbouring countries with each other.

Key market players

The national power grid network is operated by joint stock company, the Kazakhstan Electricity Grid Operating Company ("KEGOC") as the system operator. Electricity transmission organisations ("ETOs") perform contractual transmission of electricity via their own or rented electrical networks to wholesale and retail customers or electricity supply organisations ("ESOs"). ESOs purchase electricity (on the basis of a licence) from either PGOs or through centralised auctions and then re-sell electricity to consumers.

Regional electricity companies ("RECs") are ETOs of a special type that operate regional level networks, own cable or overhead power lines of, at least, four voltage classes (220, 110, 35, 20, 10 (6), 0.4kv) and have at least 10,000 connected consumers.

Regulatory authorities

The following state bodies and legal entities are primarily involved (in addition to other governmental bodies and entities) in the regulation of the electricity market:

- The Kazakhstan Government ("Government") which, among other competencies, develops the Republic of Kazakhstan ("State") policy in the electricity industry, provides state financial support to the Financial Settlement Center for Renewable Energy LLP ("FSC")[2] as a single purchaser at the capacity market (if the FSC fails to fulfil its obligation to ensure capacity availability due to insufficiency of its income) and approves various regulations and the fixed tariffs for the PGOs using renewable energy sources ("RES").
- The Ministry of Energy ("MoE"), as the competent state body, among other competencies, implements the state policy in the electricity industry sector, develops technical rules and regulations for functioning of the electricity market, approves form contracts to be used by electricity market participants, approves tariffs within its competence, monitors use of RES and resolves matters related to activity of the PGOs using RES.
- The Committee of Atomic and Energy Supervision and Control under the MoE is responsible for state energy control and supervision.
- The Committee of Environmental Control and Regulation under the MoE is responsible for compliance with the environmental law and regulations, and the issuance of environmental permits and approvals. On 17 June 2019, the Ministry of Ecology, Geology and Natural Resources was formed, to which certain functions of the MoE in the areas of formation and implementation of the State's environmental policy, waste treatment, and protection, control and supervision of rational use of natural resources were transferred.
- The Ministry of the National Economy, as an authorised body in the field of public utilities, among other competencies, performs management and inter-sectoral coordination in the field of electricity supply (0.4kV power supply facilities) within cities and settlements and coordinates work of the local executive bodies for subsidising costs of ETOs and ESOs related to servicing and repaying debt to international financial organisations attracted to implement projects of expansion, modernisation and creation of new facilities.
- The Committee on Regulation of Natural Monopolies under the Ministry of the National Economy ("Natural Monopolies Committee"), among other competences, regulates services and tariffs of natural monopolies (including services of KEGOC (such as services of technical dispatching and organising balancing of production-consumption of electricity) and ETOs), issues licences for the purchase of electricity for energy supply (required for operation of the ESOs), monitors compliance by PGOs with the set maximum tariffs, as well as monitors compliance by PGOs and ESOs with certain limitations stipulated by the Electricity Industry Law (for example, subject to exemptions, a PGO cannot purchase electricity for sale from another PGO, and an ESO cannot purchase electricity for sale from another ESO).
- The Ministry of Industry and Infrastructure Development ("MIID") is responsible for the state control (supervision) of

compliance with the technical norms and regulations[3] (through operation of its Technical Regulation and Metrology Committee and the Industrial Development and Industrial Safety Committee), for matters related to the construction of new facilities (through its Committee on Construction, Housing and Utilities Services) and is in charge of the energy efficiency and energy saving matters.

- The local executive authorities (*Akimats*), among other competencies, reserve and grant land plots for construction of power generating facilities (including those using RES) in compliance with the Land Code[4] and other applicable legislation.
- KEGOC, as the system operator, carries out centralised operational and dispatch management, ensures parallel operation with the power systems of other countries, maintains balance in the Kazakhstan unified power system, provides the system services (including transmission services, technical dispatching services, capacity regulation and reservation services, organising balancing of production-consumption of electricity) and purchases support services in the wholesale electricity market (including services to ensure capacity availability, and those related to regulating active and reactive power, and starting the unified power system from a de-energised state), transmits electricity over the national power grid network, performs technical maintenance and maintains operational readiness of the national power grid network.
- The FSC is the single purchaser of services in the capacity market, responsible for contracting electricity generation capacities (this framework is aimed at ensuring there will be sufficient reliable capacity in place to meet demand). In addition, the FSC is a participant of the wholesale electricity market and is responsible, primarily, for the centralised purchase and sale of the electricity generated by the PGOs using RES and having a power purchase agreement ("PPA") with the FSC and delivered by them to the national power grid network.
- KOREM, as the operator of the centralised trading market,[5] is in charge of the centralised electricity sales (including spot sales) and the centralised sales of capacity services. In addition, KOREM is appointed to serve as the auction organiser for the purposes of the Renewables Law.[6]
- Kazcenter HCS[7] is the organisation responsible for refurbishment and development (including from the energy efficiency perspective) of housing and communal services.[8]
- KazEnergoExpertise is the national institution responsible for developments in the sphere of energy saving and energy efficiency.[9]

Legal framework

The electricity sector in Kazakhstan is primarily regulated by the Electricity Industry Law,[10] the Natural Monopolies Law[11] and the Entrepreneurial Code.[12] The Renewables Law[13] (see section F) regulates the generation of electricity using RES and matters related to support by Kazakhstan of the use of RES. The Energy Efficiency Law[14] stipulates matters related to energy saving and energy efficiency.

The Electricity Industry Law, among other things, establishes the general legal framework for operating in the Kazakhstan electricity market, determines the roles and functions, as well as rights and obligations, of the market participants, stipulates requirements for market participants, and addresses matters of regulation of the electricity market by the State. For more on the design of the electricity market, including sales at the wholesale and retail level, support of balancing the electricity market and capacity market, see section A.3.

Under the Natural Monopolies Law, services of technical dispatching, the organising and balancing of electricity generation and consumption, as well as services of electricity transmission (and distribution), are regulated services of natural monopolies. KEGOC, as the system operator, and ETOs provide their regulated services based on approved standard form services contracts.[15] Under the Electricity Industry Law, in order to provide electricity supply services, ESOs must enter into public power supply contracts based on standard form power supply contracts.[16]

Under the Entrepreneurial Code, the State (represented by the MoE and the Natural Monopolies Committee) approves tariffs of PGOs and regulates prices in the electricity market being a 'socially significant market', including: (i) retail prices for electricity at sales by ESOs; (ii) prices for organisation and conduct of centralised trading of electricity and ensuring readiness of the trading system to centralised trading; and (iii) prices for centralised purchase and sale of electricity generated by PGOs using RES. In addition, the Entrepreneurial Code addresses matters of competition in the electricity market and state control (including the related procedures) in the electricity industry and in the sphere of energy saving and energy efficiency.

The construction, expansion and refurbishment of electricity generating facilities is regulated by the Electricity Industry Law, the Construction Law,[17] the Renewables Law and other laws and regulations.

Implementation of EU electricity directives

Kazakhstan is not a member state of the European Union ("EU").

A.2 Third party access regime

Under the general principles established by the Electricity Industry Law[18] and the Natural Monopolies Law,[19] as well as under the Natural Monopolies Operating Rules,[20] nor KEGOC or an ETO may reject access of a PGO, ESO or consumer, to the national power grid network and transmission network (subject to compliance by the PGO, the ESO or the consumers, as relevant, with the requirements established by law). Access procedures are more specifically determined in the Equal Access Rules[21] and the Power Grid Rules.[22]

Notably, under the Renewables Law, if the transmission capacity of an ETO's network is limited, priority must be granted to the PGOs using RES. The Renewables Law specifically provides that a newly constructed (as well as refurbished) RES facility must be provided with access to an ETO's transmission network (of the respective voltage class or with certain heat-carrier parameters) at the nearest point to be determined by the ETO based on the Access Rules.[23] An ETO may not refuse granting access due to the reason that its network is not technically ready or does not have sufficient capacity to accept and transmit the volume of electricity declared by the RES facility and must, at its expense, perform expansion of capacity or reconstruction of the existing transmission network, if required (and the owner of the RES facility would incur expenses related to construction of the connecting facilities from such RES facility to the network access point). No specific fee is paid to KEGOC or the ETO for connecting to the grid. Additionally, the PGOs using RES have a priority right to be included into the daily dispatching schedules of supplies into the national power grid network. In addition, under the Electricity Industry Law, RECs, to which network the RES facilities are directly connected, must accept the full volume of electricity generated by the PGOs using RES.

A.3 Market design

Wholesale market

As provided by the Electricity Industry Law, the electricity market in Kazakhstan operates on both a wholesale and retail level. The wholesale electricity market is primarily a decentralised market that functions on the basis of bilateral agreements at prices within the approved tariff. In addition, participants may buy/sell electricity at auction prices in the electricity market centrally managed by KOREM (however, the centrally managed market is substantially smaller than the decentralised market). To access the wholesale electricity market, PGOs, RECs, other ETOs, ESOs and customers must: (a) meet the qualification criteria (including the supply and purchase of not less than 1MW of average daily capacity (for PGOs using RES, average annual capacity); (b) have access to networks; and (c) sign an agreement with KEGOC as the system operator and, where required, with KOREM as the centralised trade market operator. The wholesale market operates in accordance with the Wholesale Market Rules.[24]

Electricity PPAs in the decentralised power purchase and sale market and in the centralised electricity trading market are concluded in accordance with civil legislation and must provide for, among other things, the following terms and conditions:

- a schedule of daily consumption and a schedule of hourly daily (seasonal) change in the electricity supply mode agreed by the parties;
- an indication of the points of physical and commercial metering:
  - at the point of the supply to the network by PGOs; and
  - at the point of receipt by a consumer of the contracted electricity volume from the grid network.
- terms and conditions of the electricity supply in case of accidents (or a back-up procedure);
- a procedure for limiting and terminating the electricity supply in case of a late payment by the purchaser; and
- a procedure of capacity reservation by the PGO.

Retail market

The retail market consists of individual regional markets with their own power plants, which do not participate in the wholesale market, electricity grids operated by RECs and other ETOs, as well as ESOs, traders and consumers who have not obtained the right to buy electricity in the wholesale market. The Electricity Industry Law authorises competition in the retail market between suppliers; however, in practice, the supply of electricity to retail customers is performed by RECs exclusively based on power purchase contracts. The order of access by the participants to the retail market, matters related to participation in the retail market and the rules of functioning of the retail market are defined in the Retail Market Rules.[25]

There are certain limitations stipulated by the Electricity Industry Law related to operations in the electricity market. PGOs may therefore not: (i) sell electricity to individuals or legal entities who are not participants in either the wholesale or retail market (this rule does not apply to export sales); (ii) starting from 1 January 2019, sell electricity to wholesale market participants who do not have agreements with the FSC on purchasing capacity of generating facilities; and (iii) purchase electricity from other PGOs (except for purchasing for own needs, in case of accidents or in case of purchase from the FSC of electricity generated from RES), with the view to re-sell. An ESO is prohibited from selling electricity to another ESO other than on the balancing market.

Balancing market and the market of system services

Under the Electricity Industry Law, participants of the wholesale electricity market must participate in the balancing electricity market in accordance with the Electricity Industry Law and the Balancing Market Rules.[26] KEGOC also provides a market of system services.

Capacity market

The capacity market became functional as of 1 January 2019 and functions in accordance with the Capacity Market Rules.[27] The participants of the capacity market are KEGOC (as the system operator), the FSC (as a single purchaser), PGOs, consumers, and KOREM (as an operator of a centralised trading market). ETOs, ESOs and consumers, as participants of the wholesale electricity market, must enter into contracts with the FSC, as a single purchaser, and must participate in the capacity market on the basis of such contracts. A contract for the purchase of services to maintain the capacity availability (readiness) and a contract for rendering services of ensuring the capacity availability to bear the load are concluded by the market participants with the FSC on the basis of the approved model contracts.[28]

Several types of capacity purchase agreements ("CPA") are available on the market. Newly commissioned generating facilities with a cycling regime execute CPA with the FSC on the basis of an auction price and, in addition, enter into a recently introduced capacity regulating service agreement with the system operator. Individual CPAs are also available for the modernisation of existing power stations (on the basis of direct negotiations with the authorised body) as well as commissioning new power stations (on the basis of a tender). All other PGOs (to the extent that they have free certified capacity not used for intra-group purposes or export) should sell their capacity through centralised trades.

RES energy market

The RES energy market is integrated in the overall electricity market, as follows. A PGO using RES may, at its sole discretion, sell electricity it generates either to the FSC at the fixed tariffs and the auction price ("FSC Sale Option"), or directly to consumers ("Direct Sale Option"). For more information regarding such sale and purchase arrangements, as well as the fixed tariffs and auction prices see section D.

In order to implement the FSC Sale Option, a PGO using RES must enter into a sale and purchase agreement (or a PPA) with the FSC in the established form,[29] under which the FSC must purchase, for a period of 15 years (20 years for PPAs entered into after 1 January 2021), the entire volume of electricity generated by such PGO using RES and delivered into the grid. Having entered into the PPA, the FSC in turn enters into sale and purchase agreements (ie PPAs) with notional consumers (*uslovniye potrebiteli*) ("Notional Consumers")[30] ("NC PPAs"). Under the NC PPAs, the Notional Consumers purchase pro rata from the FSC, at the support tariff, electricity generated by the PGOs using RES who are parties to the PPAs with the FSC. Expenses of the Notional Consumers related to purchase of electricity from the FSC are then allocated pro rata among the consumers that purchase energy from the Notional Consumers.

The law also distinguishes Qualified Notional Consumers, which are (or have within one group) both the Notional Consumers and, at the same time, PGOs using RES that either use all electricity generated at their RES facilities for own (or intra-group) purposes or sell it under the Direct Sale Option (ie when the FSC Sale Option is not exercised). Similar to a Notional Consumer, a Qualified Notional Consumer also pays the FSC for electricity generated by independent PGOs using RES but the amount of payments decreases in reverse proportion to a share of electricity generated by the Qualified Notional Consumer from RES PGOs in the total production of that Qualified Notional Consumer. A Qualified Notional Consumer will not be charged if the ratio of electricity generated by its intra-group RES PGO to the total production of the group is higher than the lower of two other ratios, namely the Kazakhstan ratio of RES PGO production and the ratio set out for a given period by state planning documents.

A.4 Tariff regulation

Below is a general overview of the price regulation in the electricity market; for tariff regulation for RES objects see section D.

KEGOC

KEGOC provides regulated services based on the approved tariffs. As of 30 May 2022, the following tariffs (all not including VAT) are in effect:[31]

- 2.594 Kazakhstani Tenge ("KZT") per kWh for transmission of electricity by the national power grid network until 30 September 2022 and KZT2.645/kWh afterwards and until 31 May 2023;
- KZT0.285/kWh for technical dispatching until 30 September 2022 and KZT0.294/kWh afterwards and until 31 May 2023; and
- KZT0.091/kWh for organising balancing of the electricity generation-consumption until 30 September 2022 and KZT0.095/kWh afterwards and until 31 May 2023.

FSC

In 2022, the service fee to ensure the availability of electrical power to bear the load (or readiness of electric power for bearing the load)[32] is KZT711,432/MW per month (not including VAT).[33]

KOREM

KOREM's service of organisation and conduct of centralised trading of electric energy is paid by the participant of the electricity wholesale market, ie a participant of centralised trading, based on volumes of transactions for electricity sale and purchase registered in the trading system, at a rate of KZT0.002/kWh (not including VAT).[34]

KOREM's service of ensuring readiness of the trading system to conduct centralised trading of electric energy is paid, from 1 May 2018, by the wholesale electricity market entity based on the volume of electricity purchased and sold on the wholesale electricity at a rate of KZT0.0033/kWh.[35]

KOREM's service of organisation and conduct of the centralised trading of electricity capacity is paid by participants of the centralised trades at a rate of KZT1,139,710 (not including VAT) per participant of the centralised trades.[36]

PGOs (except for PGOs using RES)

Kazakhstan has a double-rate electricity tariff whereby conventional PGOs receive proceeds for sale of electricity and separately may receive payments for the capacity.

Currently, a PGO may not sell electricity at prices above the approved tariffs, except for spot trades, sales on the balance market or export sales. Approved tariffs currently include a capped tariff, estimated tariff and individual tariff. Capped tariff for the period of 2019 to 2025 is approved by the MoE[37] for various groups of PGOs (there are currently 47 groups of PGOs)[38] and is based on the prices of energy in the preceding year, the inflation rate and the expenses of producers for capital assets, expansion, renovation, reconstruction and re-equipping. Estimated and individual tariffs are approved by the authorised bodies on an individual basis and, generally, take into account investment needs of the PGO.

Starting from 1 January 2019, the capacity market began operating on which PGOs should get a major part of the revenues as payments for the capacity of generating facilities (to come from wholesale market participants through the FSC, as a single purchaser) and lesser amounts as payments for electricity (as previously, to come from customers). A capacity tariff is either a capped tariff or an individual tariff to be assigned on the basis of a CPA (see section A.3). The capped tariff is approved for the period of 2019 to 2025 at a rate of KZT590,000/MW per month (not including VAT).[39] The final capacity tariff is calculated as the sum of capacity tariffs under CPAs, amounts determined on the centralised trades, amounts required for combined cycle heat power stations to produce heat and FSC's expenses and then divided between all customers, generally, in proportion to the electricity consumed. There has been a steady decline in the number of investments into new/renovated generation since 2010-2015. The introduction of a capacity tariff did not revert this trend, rather, the tariff acted to the contrary.[40]

ETOs

ETOs are natural monopolies and their transmission tariffs are approved by the Natural Monopolies Committee on a 'cost-plus' basis. Provided that there is an approved investment plan, the tariff may also include capex investments. Under the Renewables Law, PGOs using RES are exempt from paying for services of the ETOs.

ESOs

Under the Electricity Industry Law, ESOs charge their customers on the basis of a public contract (meaning equal terms for all customers except as otherwise provided by law). The tariffs are differentiated by the volume of electricity consumed, vary for industrial and various types of individual customers and are available on the website of the Natural Monopolies

Committee.[41] The Natural Monopolies Committee does not directly approve ESOs' tariffs, but it monitors prices for electricity being a 'socially significant market'. If abuse of power is found, the Natural Monopolies Committee may initiate court hearings resulting in the return or confiscation of unlawful income received.

A.5 Market entry

Based on the structure of the electricity market, a new entrant may wish to become either a PGO, an ETO or an ESO, each of which operates in the form of a legal entity. There are no known limitations for a foreign investor to participate in or operate as a PGO, an ETO or an ESO. In practice, a foreign investor may need to establish a presence in Kazakhstan (eg in the form of a Kazakhstan legal entity or through registration of a branch office). In this regard, corporate governance (in accordance with Kazakhstan law), employment and work permits (and visas), currency control (related to 'direct investments' and financing) and tax (related to operations and payment of dividends) matters may need to be considered.

Subject to compliance with the set (qualification) requirements (including possession of the respective assets and employment of qualified staff), obtaining a licence or certification (attestation), where necessary, and entering into a contract with other market participants (such as KEGOC, the FSC and KOREM) in compliance with law (no specific legal barriers exist). For more information regarding such matters see section A.1.

In practice, obtaining the required licence (of certification), as well as work on approval of tariffs by the competent authorities, may take significant time and effort.

Depending on the function (role) in the electricity market, in practice, the market participant will have to address a wide range of operational matters, including (but not limited to) receiving applicable operational authorisations and permits (eg those related to construction of new generation facilities, environmental permits, etc), obtaining land use rights for a new facility (if needed), maintaining of mandatory insurance under the law and data protection matters. The market participant (such as the PGO) may need to analyse if it is eligible for any investment-related incentives in connection with operations (ie those generally available to investors under the law).

The construction and operation of RES PGOs is subject to essentially similar regulatory requirements as listed above for conventional PGOs. See section F for the specifics of the market entry requirements for RES PGOs.

Licensing regime

No licence for generation and transmission of electricity is required under the law.

Under the Electricity Industry Law[42] and the Permits and Notifications Law,[43] the Natural Monopolies Committee issues licences for the purchase of electricity for energy supply (which must be obtained by ESOs) ("Purchase and Supply Licence"). The Purchase and Supply Licence is issued for an indefinite period of time (subject to the licensee continuing to meet set qualification requirements)[44] except that the Purchase and Supply Licence may be terminated in cases determined by the Permits and Notifications Law.[45] Under the Permits and Notifications Law, a Purchase and Supply Licence is not transferrable or assignable.

According to the approved rules for issuance of Purchase and Supply Licences,[46] it may take up to 15 business days (and more, in practice) from submission by the applicant of the complete set of the required documents, to receive the Purchase and Supply Licence. Notably, such set of documents includes, among other things: (i) evidence from a bank confirming availability of working capital in the amount of, at least, 10,000 times the monthly calculated index ("MCI")[47] (currently, KZT30,630,000); (ii) a contract or a protocol of intent between the applicant and a PGO and an ETO for the supply and transfer and/or distribution of electricity (including outside the region, with the condition of backup replacement in case of accidents); (iii) title documents confirming availability of a building or a room for working with consumers and locating subscriber services (which may also be leased); and (iv) evidence of establishing a service for work with consumers (or subscriber services). A licensing fee must be paid for the issuance of a Purchase and Supply Licence; the fee is calculated at ten times the MCI (currently KZT30,630).

In addition:

- A PGO will provide a service of maintaining the capacity availability only after receipt of certification (attestation) of the electric power capacity of its generating facilities. KEGOC certifies, annually, capacity of the power generating facilities in the established procedure.[48]
- ETOs must comply with the specific qualification requirements for electricity transmission activity. Such compliance is determined in line with the approved procedure.[49]
- Under the Permits and Notifications Law, annual qualification examination of knowledge of technical operation rules (or technical conditions) and safety rules by managers and specialists of PGOs, ETOs, RECs and ESOs must be conducted in the established procedure.[50]

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Eliminating accidents and guaranteeing continuous electricity supply

Under the Electricity Industry Law,[51] to ensure no accidents occur, the system operator acts according to the established rules[52] and uses the capacity of PGOs, regardless of form of ownership, and autonomous power sources of consumers. If an imbalance occurs that is not covered by the balancing market of electric energy, the system operator can buy and sell electricity in order to maintain the regulatory frequency of electricity in Kazakhstan's unified power system.

Under the Electricity Industry Law,[53] to secure a continuous power supply for consumers, consumers, ETOs and ESOs must sign an act of emergency booking (*akt avariinoi broni*) and an act of technological armour of power supply (*akt tekhnologicheskoy broni*) ("Reservation Acts") for an emergency reservation in case of an accident in the system, as suspension of activity of certain consumers due to a power supply interruption may cause damage to life and people's health, and damage to the environment. The procedure and conditions of power supply for consumers who have an emergency reservation is approved by the MoE.[54] In case of an accident in the system, the power supply is carried out according to the systems developed by the ETOs that ensure a power supply in the amount determined in the Reservation Acts.

Energy efficiency

The Energy Efficiency Law[55] establishes regulatory requirements aimed at improving energy efficiency, including the requirement to consider energy efficiency when designing industrial and residential property (except for temporary or individual houses), an obligation to label devices consuming electricity with energy efficiency class, limitation on the use and sale of filament lamps of more than 25Wt capacity, prohibition of use and sale technologies and materials not meeting legislative requirements in energy efficiency in newly constructed or reconstructed buildings, energy audit and the requirement of complex expertise in the part of energy efficiency for facilities consuming energy resources in the amount of 500,000 tonnes or more of conditional fuel (*uslovnoye toplivo*) or unique facilities.

Smart metering

Under the Energy Efficiency Law, promotion of the use of energy saving equipment and materials is a major direction of State policy and regulation in the field of energy saving and energy efficiency.

The Energy Efficiency Law[56] provides that use of energy saving materials and installation of energy and water metering devices, as well as automated heat consumption control systems, are pre-requisites for implementing projects of construction of facilities consuming energy and water resources. Construction of residential houses with multiple apartments requires use of energy saving materials, installation of general household meters for heat and water, apartment meters for electrical energy, cold and hot water, gas, as well as control devices in heating systems, and automated heat control systems. Commissioning of new facilities consuming energy and water resources that are not equipped with energy and water metering devices and automated heat consumption control systems is not permitted. The above requirements for automated heat consumption control systems do not apply to facilities with an average hourly consumption of thermal energy (including the costs of thermal energy, heating, ventilation, air conditioning and hot water) of less than 50kW.

Further, the Energy Efficiency Law[57] stipulates that, in order to save energy and increase efficiency of energy resources used by individuals and legal entities, including governmental agencies and entities of the quasi-public sector, certain energy service agreements (in the established form)[58] may be concluded with energy service companies. Such energy service agreements may provide for use of the energy saving equipment for implementing certain energy saving measures. The Energy Efficiency Law broadly defines the energy saving equipment as any equipment that improves the efficiency of energy resources.

The use of smart meters is not expressly envisaged by the Energy Efficiency Law, however, according to public sources,[59] in practice, certain projects using smart meters have been recently implemented in Kazakhstan. Further, Kazcenter HCS actively promotes using smart meters for energy saving purposes.[60] Using smart meters and other energy saving equipment may, in practice, trigger the requirement to obtain the applicable certificate of verification under the technical regulation laws. Under general principles, measuring instruments used for electric energy metering must be of the types included in the special register for ensuring uniformity of measurements.

Electric vehicles

Kazakhstan provides a number of tax and customs duty incentives for electric vehicles ("EVs"). Specifically, the import of EVs is released from import customs duties,[61] EV (excluding hybrid vehicles) owners do not pay transport tax[62] and there is zero utilisation fee (paid by an importer or producer).[63]

In terms of domestic production and infrastructure, Kazakhstan is at a preliminary stage. There are 110 charging stations in Kazakhstan, mainly in Nur-Sultan and Almaty and, as of 1 January 2021, 577 EVs were registered in Kazakhstan. Local producers are currently assembling the 'YUTONG' and 'Golden Dragon' electric buses in small numbers and there is a certain amount of locally produced JAC electric cars. Recently, the Vice Minister of the Ministry of Industry and Infrastructure Development announced that in 2022, sales of the electric car Hyundai Ioniq should start and in 2023, the KIA EV6.

Use of EVs

The Automobiles Law[64] does not specifically refer to EVs. In recent years, however, Kazakhstan has developed certain technical regulations that provide requirements for EVs including the technical regulation, the 'Requirements for Safety of Auto Transport Vehicles'[65] (which is based on technical requirements adopted in accordance with the 1958 Geneva Agreement concerning the Adoption of Harmonised Technical United Nations Regulations for Wheeled Vehicles, Equipment and Parts which can be Fitted and/or be Used on Wheeled Vehicles and the Conditions for Reciprocal Recognition of Approvals Granted on the Basis of these United Nations Regulations).

In addition to national standards, the import and use in Kazakhstan of EVs (as with other vehicles) is regulated by technical requirements (including a technical regulation on safety of wheeled vehicles)[66] and customs rules of the Eurasian Economic Union ("EAEU") (ie the respective custom fees are paid on vehicles imported from outside the EAEU).

Production of EVs

There are no specific regulations or incentives related to producing and assembling EVs in Kazakhstan. Applicable legislation includes general investment legislation and legislation for 'green' and ecologically clean projects. Specifically:

- Article 62 of the Industrial Policy Law[67] provides for an agreement on industrial assembling of vehicles to be entered into between the authorised body in the field of state stimulation of industry and the producer. Provided that the requirements as to the local origin set out in the Rules of Industrial Assembling of Vehicles[68] are met, the agreement permits selling the assembled vehicles within the EAEU as a Kazakhstan origin product.
- An agreement on the industrial assembling of vehicles is a pre-condition to obtain a special investment contract as set out by paragraph two of Chapter 25 the Entrepreneurial Code.[69] Subject to several conditions, a special investment

contract allows release from customs duties on technological equipment and spare parts thereto.

- Article 388 of the Environmental Code[70] provides that the collected utilisation fee should be spent on, among other things, the production, in Kazakhstan, of ecologically clean vehicles, including EVs. Currently, collected utilisation fees are used to reimburse certain expenses related to waste collection and utilisation and to finance purchase of locally produced cars by individuals.
- The purchase of EVs is considered as a purchase of 'clean transport'[71] and implementation of 'green' technologies. Specific incentives for 'green' technologies are still unclear, however, it may include access to 'green' financing and a number of other state support measures.

A.7 Cross-border interconnectors

Kazakhstan's grid configuration is fully determined by its Soviet history and cheap electricity available from its northern neighbour, the Russian Federation. There are three energy zones in Kazakhstan, the West zone, North zone and South zone. The Atyrau energy site has 110kV connection with Russian Federation and the West Kazakhstan region has three 220kV connections with Russian Federation. Both Atyrau and the West Kazakhstan region are parts of the West zone that do not have sizeable connections with the North and South zones and, are effectively more a part of the Russian Federation energy system than Kazakhstan's system. The North zone is energy positive and has several 220-500-1100kV connections with the Russian Federation. The South zone is energy negative and mostly receives energy via three 500kV lines from the North region, one of which goes to Kyrgyzstan and, further, to Uzbekistan.

On inter-state balance, Kazakhstan is mostly neutral, ie it produces roughly the amount of electric energy it consumes, with the tendency to enter an energy deficit. However, interconnections with the Russian Federation are important to cover day-night disbalances as Kazakhstan does not have sufficient cycling power.[72]

Under the Electricity Industry Law, the MoE carries out international cooperation in the field of electricity, while KEGOC, as the system operator operates the interregional and interstate power lines (together with the related facilities and infrastructure), and conducts the centralised operational and dispatch management in respect of the interregional and interstate power lines.

Under the Electricity Industry Law, interregional and interstate power lines are power lines of 220kv and above that ensure transfer of electrical energy between regions and states. Together with the respective substations and switchgears, the interregional and interstate power lines form the national power grid network (which in turn, is a part of the Kazakhstan unified power system). The national power grid network is not subject to privatisation and must be owned by the national company (ie KEGOC).

KEGOC, as the system operator, carries out the centralised operational and dispatch management in respect of the entire unified power system (including in respect of the interregional and interstate power lines) in accordance with the Electricity Industry Law[73] and specific regulations.[74] Such dispatch management includes, among other things, management of the inter-state electricity flows on the terms and conditions of parallel operation of the Kazakhstan unified power system with the power interconnections of neighbouring countries (including the power systems of the Russian Federation and countries of Central Asia), and development of operational and dispatching documentation for interaction with dispatch centres and participants in the wholesale electricity market in neighbouring states.

Management of interstate electricity flow is affected through:

- the monitoring, and performance of, the terms and conditions of agreements entered to ensure parallel work with energy systems of the neighbouring states;
- conducting technical expertise and control of terms and conditions of supply contracts and contracts for transmission of electricity by the interstate power lines; and
- regulating (balancing) deviations from the agreed volumes of the interstate electricity flows.

KEGOC provides services for technical dispatching of supply to the grid and consumption of electricity (based on agreements in the established form) to PGOs, ETPs, ESOs and consumers who supply (import) electricity to Kazakhstan.

In May 2014, the EAEU member states, including Kazakhstan, signed the Treaty on the Eurasian Economic Union ("EAEU Treaty").[75]

Chapter XX (Energy) of the EAEU Treaty is dedicated to matters of cooperation between member states in the energy sphere, including through the formation of a common electricity market and granting access to services of natural monopolies in the electricity sector in the member states. Under the EAEU Treaty, the Supreme Eurasian Economic Council approved in May 2015, the concept of forming a common electricity market of the EAEU,[76] and in December 2016, the programme of forming a common electricity market of the EAEU.[77] On 29 May 2019, an international agreement on the formation of a common electricity market was signed in the form of a protocol to the EAEU Treaty. It is anticipated that this protocol will come into force upon its ratification by all of the EAEU members (Kazakhstan ratified the protocol in March 2022, at which time ratification by Kyrgyz Republic and the Russian Federation remained outstanding. Further, on 20 December 2019, a plan of measures aimed at forming a common electricity market of the EAEU was approved by the Supreme Council of the EAEU. Formation of the common electricity market within the EAEU may, in theory, impact matters related to ownership and operating the interconnectors, however, it is unlikely that this will be to a significant extent (ie it is likely that KEGOC will keep providing operating and dispatching services).

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Under the Law on Natural Monopolies ("Monopolies Law"),[78] the transportation of oil and oil products by main pipelines[79] is considered a natural monopoly and is therefore subject to regulation. As a consequence, the National Oil Transportation Company, KazTransOil ("KTO"), as well as subsidiaries of National Company QazaqGaz JSC ("QazaqGaz") (ie JSC Intergas Central Asia and JSC Kaztransgas Aimak) are included in the list of subjects of natural monopoly in the field of downstream operations.

Under the Monopolies Law, the State regulation of natural monopolies includes, among other things, the formation, setting and approval of tariffs, and granting consent for consummation of certain actions by the subjects of natural monopoly. Natural monopolists must provide services to all customers on equal terms on the basis of an approved tariff and are forbidden to impose additional conditions of access to their services.

It is no longer possible to enter into production sharing agreements ("PSAs") in Kazakhstan. However, a few PSAs signed prior to 2009 still remain valid. Currently, rights to exploration and production of oil and gas resources can be obtained only through execution of concession (tax royalty) contracts, which are based on 'standard contracts' approved by the Government. Prior to September 1999, exploration and production ("E&P") rights in Kazakhstan were granted based on both a licence and contract. By law, licences issued before September 1999 are considered to be in effect, although in practice they are virtually ignored and the rights are set out in contracts.

Between September 1999 and 2018 (ie until the Subsurface Use Code ("Code")[80] came into effect) subsurface use rights in relation to all types of useful minerals were granted through execution of exploration, combined E&P, or production contracts. Currently, only E&P of hydrocarbons as well as production of uranium are regulated through execution of subsurface use contracts with the competent authority while all other operations are carried out based on a licence. For further details regarding the upstream regime in oil and gas, see section F.

Key market players

The National Company KazMunayGas JSC ("KMG") plays an important role in the petroleum industry in Kazakhstan. By law, it is entitled to hold at least a 50% interest in any offshore project in the Kazakhstan sector of the Caspian Sea. KMG is also the parent company of several key market players. For instance, one of its subsidiaries is KTO, which owns the biggest network of main oil pipelines in Kazakhstan. KTO renders oil transportation services and acts as the national operator of oil pipelines. See also below, Regulatory authorities.

Regulatory authorities

The Government is responsible for developing and implementing the State's general subsurface use policy as well as organising management of the subsurface, establishing restrictions and prohibitions for use of the subsurface, approval of the list of strategic fields and other matters.

In turn, the MoE is the competent authority acting on behalf of the State and is the main state body that regulates the activities related to exploration and production of hydrocarbons. The MoE's powers include granting of E&P rights; negotiation, execution, amendment, and termination of oil and gas contracts; control over fulfilment by the subsurface users of contractual obligations, approval of direct and indirect transfers of E&P rights and registration of pledges over such rights. In addition, with respect to strategic fields, the MoE has the right to require amendments to oil and gas contracts in order to restore the economic interests of the State, if the change in the economic interests of the State is caused by the subsurface user and such change poses a threat to its national security. In the event that amendments cannot be agreed upon, the competent authority may unilaterally terminate a subsurface use contract.

The Ministry of Ecology, Geology and Natural Resources[81] oversees compliance with environmental protection and, among others, granting access to, record-keeping and storage of geological information. Other state agencies overseeing the oil and gas industry include the Ministry on Emergency Situations, the Ministry of Healthcare, Ministry of Finance and other republican state agencies. Local authorities (*Akimats*) are responsible for granting land use rights and general oversight over the use and protection of land, water and the environment.

Legal framework

According to the Kazakhstan Constitution as well as the Code, the subsurface and useful minerals within it, including oil and gas, belong to the State. The State may grant the rights to use the subsurface to individuals and legal entities on the basis of subsurface use contracts for E&P or production of hydrocarbons. Such contracts are concluded by the MoE on behalf of the State. Oil and gas produced on the basis of a subsurface use contract is the property of a subsurface user, save for a few exceptions such as associated gas, which, under the law, is owned by the State unless otherwise provided in the subsurface use contract.

In addition to the Code, the Law on Main Pipelines ("Pipelines Law")[82] regulates the right of ownership, the right of access, and other issues related to main pipelines. Other important legislative acts relevant to the oil and gas industry include the Environmental Code, the Land Code, and the Tax Code.

Gas

Nature of the market

Under the Monopolies Law, the storage and transportation of commercial gas by a connecting gas pipeline, main gas pipeline or gas distribution system, and the transportation of raw gas by connecting gas pipelines[83] are considered a natural monopoly and are therefore subject to regulation. See also above, Oil, Nature of the market.

Key market players

QazaqGaz is the largest gas supply company in Kazakhstan, representing the interests of the State on the domestic gas market and worldwide. QazaqGaz is a new name of KazTransGas JSC, change of the name was carried out in 2021. QazaqGaz is a subsidiary of the Sovereign Wealth Fund "Samruk-Kazyna" JSC. It participates in the implementation of state policy in the sphere of gas and gas supply, ensures transportation and storage of commercial gas, develops, finances, constructs and operates pipelines and gas storage facilities. QazaqGaz 's authorities also include exercise of the State's pre-emptive right to acquire raw and commercial gas. QazaqGaz's subsidiary, Intergas Central Asia JSC ("ICA") is the national operator of main gas pipelines. See also above, Oil, Key market players.

Regulatory authorities

See above, Oil, Regulatory authorities.

Legal framework

The Law on Gas and Gas Supply ("Gas Law")[84] regulates the gas industry. It establishes a state-wide unified system for gas supply, conditions for fulfilment of Kazakhstan's internal gas requirements, the implementation of state policy with respect to associated gas, etc.

Implementation of EU gas directives

Kazakhstan is not an EU Member State.

B.2 Third party access regime to gas transportation networks

The transportation of commercial gas by a connecting gas pipeline, main gas pipeline or gas distribution system, and the transportation of raw gas by connecting gas pipelines is subject to regulation by the Monopolies Law.

Natural monopoly entities must, among other things, give consumers equal terms of access to regulated services and post on their website (or provide a link to the authorised body's website) information on free and accessible capacity. Natural monopoly entities are prohibited from:

- charging consumers for provision of information regarding free capacity;
- creating unequal conditions of access to regulated services; and
- restricting the activities of a consumer to carry out works in accordance with technical conditions for connecting to the network of the natural monopoly entity.

In addition, according to the Pipelines Law, if there is free throughput capacity, an owner of a main pipeline must provide equal conditions of access to services on transportation of products through a main pipeline to all shippers subject to limitations established by the law. When there is a limited capacity, the Pipelines Law sets the order of priority based on which the capacity of the main pipeline must be used.

B.3 LNG terminals and gas storage facilities

A subsurface use licence for use of subsurface space is required for the placement and operation of underground gas storage facilities at a depth more than five metres from the land surface. The construction and operation of underground and above-ground gas storage facilities is subject to a number of permits and approvals.

By law, gas storage is considered a natural monopoly. Therefore, the same regulatory framework regarding subjects of a natural monopoly apply to gas storage facilities.

Under the Gas Law, services for transporting commercial gas by connecting main pipelines as well as services on storage of commercial gas at storage facilities may be provided only by gas transportation companies. At the same time, gas transportation companies must refuse provision of services on transportation and/or storage of commercial gas to the owner of commercial gas in case of:

- non-compliance of the commercial gas to the requirements of technical regulation and national standards; and
- failure by the subsurface user to provide a written waiver of the national operator from the pre-emptive right of the State for acquisition of commercial gas planned for transportation or documents confirming receipt by the national operator of the commercial proposal by the subsurface user to alienate the volume of commercial gas planned for transportation.

B.4 Tariff regulation

According to the Pipelines Law, tariffs for services on transportation of products through a main pipeline, with the exception of its transportation for the purpose of transit through the territory of Kazakhstan and export outside Kazakhstan, is set in accordance with natural monopolies legislation of the State.

For the Monopolies Law, the following methods of tariff regulation of natural monopoly areas apply when a tariff is formed:

- cost method (the method of tariff formation depending on the itemised, economically reasonable costs and profits of a natural monopoly entity);
- incentivising method (the method of tariff formation depending on compliance with the indicators of quality and reliability of regulated services and the achievement of performance indicators by natural monopoly entities);
- indexation method (tariff formation by annual indexation of an approved tariff by a low-power natural monopoly entity); and
- determination of a tariff on the basis of an executed PPP agreement, including a concession agreement.

Tariffs should provide for the reimbursement of costs for the provision of a regulated service and the generation of profits for the development and efficient operation of the natural monopoly entity.

A tariff is normally set for a period of five years or longer. For the approval of a tariff by the authorised body, the Committee for the Regulation of Natural Monopolies ("CRNM"),[85] a natural monopoly entity should submit an application. The application should be reviewed by the authorised body within 90 business days from the date of its submission. The decision on the approval of the tariff should be sent to the natural monopoly entity no later than five calendar days from the date of the decision approving it. A tariff will be effective as of a date not earlier than the first day of the second month following the month in which the tariff was approved. However, a natural monopoly entity must notify consumers of the approval of the tariff no later than 30 calendar days prior to such tariff's effective date.

Among other things, the Monopolies Law establishes the following grounds for changing a tariff approved by the authorised body:

- declaration of an emergency;
- any change in the rates of taxes and other obligatory payments to the State budget in accordance with the tax legislation;
- an increase in the volume of regulated services provided; and
- failure to comply with quality and reliability indicators of regulated services.

A tariff change may be carried out at the initiative of the authorised body or a natural monopoly entity no more than once a year.

According to information posted on the website of CRNM, tariff limits have been established for natural monopolies such as Intergas Central Asia JSC and KazTransGas Aimak JSC.

B.5 Market entry

Subsurface use rights can be obtained through one of the following:

- granting of subsurface use rights by the competent authority, ie MoE;
- the transfer of the subsurface use rights (a part thereof) on the basis of civil law transactions, ie from another subsurface user; and
- the transfer of subsurface use rights by way of succession on reorganisation of a legal entity or inheritance.

There are no restrictions for local or foreign individuals or legal entities to obtain subsurface use rights for the exploration or production of hydrocarbons as long as they meet the requirements set by the Code for applicants. Such requirements include that the applicant should not be in a stage of liquidation, reorganisation or bankruptcy, should not have tax arrears to the budget, and must have financial capabilities sufficient for fulfilment of minimum work requirements during exploration. To obtain subsurface use rights for offshore operations, in addition to meeting the above requirements, the applicant must also have positive experience of offshore petroleum operations in the territory (including the continental shelf of Kazakhstan) or outside of Kazakhstan. In case of a legal entity, the requirement regarding offshore operations will be considered satisfied if its parent company, owning not less than 25% of shares or interests in it, has the relevant experience.

Subsurface use rights for hydrocarbons are granted via either an auction or through direct negotiations (only in case of rights being granted to the national company, ie KMG). In auctions, the participant that offered the highest amount of the signature bonus will be the winner of the auction.

In addition, with limited exceptions, MoE's consent as well as the waiver of the State's priority right (if applicable) is required for the acquisition of subsurface use rights or shares/interests directly or indirectly holding subsurface use rights. The State's priority right only applies to strategic fields, the list of which is approved by the Government. Under the Code, a field will be a strategic field if it (i) has geological reserves of (a) more than 50 million tonnes of oil, or more than 15 billion cubic metres ("bcm") of natural gas; (ii) is located in the Kazakhstan sector of the Caspian sea; or (iii) is an uranium field.

The Pipelines Law regulates the right of ownership, right of access as well as other issues related to main pipelines. A 'main pipeline' is defined as a single production and technological complex consisting of a linear part and the facilities ensuring safe transportation of the products[86] that meet technical specifications and national standards. Main pipelines include the main oil pipelines, gas pipelines and oil-products pipelines.

Main pipelines may be in both private and state ownership. However, individuals and foreign legal entities (ie entities registered under legislation of another state) cannot own main pipelines. In addition, the Government has a priority right to participate in construction of any new main pipeline in the amount of not less than 51%.

Main pipelines and shares in legal entities owning them, as well as shares in legal entities, which have the power to directly or indirectly determine or influence the owners' decisions, are considered 'strategic objects'. Any sale of a strategic object requires a preliminary consent of the Government and is subject to the State's priority right. This requirement does not apply to the sale and purchase of shares at a stock exchange.

Similarly, under the 2012 Gas Law, the national operator has a priority right to acquire any facilities within the Unified Commercial Gas Supply System ("UCGSS") or any shares and interests in legal entities directly owning or having rights to UCGSS facilities. UCGSS includes trunk and connection gas pipelines, gas storage facilities, gas distribution systems, and gas consuming systems, and gas compressor stations.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Kazakhstan's laws do not directly impose PSOs in the oil and gas sector. However, under the Code, subsurface users (ie production entities) must annually finance projects on social and economic development of the region and development of its infrastructure. In particular, starting from the second year of the production period, subsurface users must finance social and economic development of the region and development of its infrastructure in the amount of 1% of the investment made under the subsurface use contract. Subsurface use contracts signed prior to the adoption of the Code may also provide for social obligations during the exploration period.

Smart metering

According to the Code, starting from 1 January 2020, business entities engaged in the turnover of crude oil and gas condensate must equip their facilities with control metering devices. The term 'turnover' includes preparation, transportation, storage, dispatching, sale, import and export of crude oil and gas condensate into and out of the territory of Kazakhstan.

The Gas Law generally provides that gas metering devices, among others, must be used for the metering of gas transportable by main gas pipelines, gas transportable by distribution systems, gas used by industrial and municipal consumers and by household consumers. Such gas metering devices must comply with the requirements of technical regulations and national standards.

B.7 Cross-border interconnectors

The Pipelines Law provides that operational dispatching management by a cross-border main pipeline will be carried out in accordance with the terms of an international agreement of the State or an agreement concluded between the owners of a cross-border main pipeline.

KTO was appointed as the national operator of main oil pipelines as per Government Decree no. 1273 dated 8 October 2012. As the national operator of main oil pipelines, KTO has the right to provide services on organisation of transportation of oil transported from the territory of Kazakhstan through the pipeline systems of other states. As such, KTO's functions also include conclusion of agreements with shippers of oil for organisation of transportation of oil through the pipeline systems of other states, and, on the basis of such agreements, conclusion of corresponding agreements with both local and foreign entities for transportation, trans-loading through marine shipping terminals and others.

C. Energy trading

C.1 Electricity trading

For information regarding Kazakhstan's electricity market structure, the market design, the market trading arrangements and applicable tariffs, see sections A.1, A.3 and A.4.

C.2 Gas trading

Kazakhstan is in the top 30 countries in terms of reserves and production of gas. By the end of 2021, the commercial gas production was expected to reach 29.4bcm. Due to a lack of infrastructure in remote regions (close to Russia, Uzbekistan and Turkmenistan), Kazakhstan imports gas to meet gas consumption requirements of such regions. In 2021, Kazakhstan imported 7.7bcm.[87] According to some forecasts,[88] by 2040, gas consumption in Kazakhstan may exceed 31bcm.

General principles of gas sales

According to general principles of the Gas Law,[89] in order to protect the environment and public health, only commercial gas,[90] liquefied natural gas ("LNG") and liquefied petroleum gas ("LPG") are supplied to Kazakhstan consumers (except for sale of raw gas to industrial consumers for use as a raw material). The Gas Law specifies which persons may carry out sales of each of commercial gas, LNG and LPG. The Gas Law provides households and utility consumers with the priority right to use commercial gas or LPG.

In order to meet the LPG needs of the domestic market, the MoE prepares and approves monthly a delivery plan based on consolidated applications of the local executive authorities (*Akimats*) ("Delivery Plan"). The Delivery Plan consists of two parts: (a) a plan of LPG supplies out of the electronic trading platforms, which is prepared based on applications of the gas network organisations and industrial consumers using LPG as a raw material for petrochemical products; and (b) a plan of LPG supplies through the electronic trading platforms based on applications of the electronic trade participants, which are submitted to the local executive authorities. LPG producers and owners of LPG produced as a result of processing of their raw hydrocarbons must comply with the Delivery Plan.

Categories of persons entitled to participate in LPG trades through electronic trading platforms, requirements for organisers and participants of the LPG electronic trading, as well as the minimum and maximum sizes of monthly LPG batches that may be purchased through the electronic trading platforms are set in the LPG Electronic Trading Rules,[91] which came into force only on 1 January 2019.

Wholesale and retail markets of commercial gas

As per the Gas Law, the gas market in Kazakhstan operates on both a wholesale and retail level.

Only the national operator (ie QazaqGaz JSC), producers of commercial gas, subsurface users who are owners of commercial gas produced in the course of processing of their raw gas, owners of commercial gas produced outside of Kazakhstan and imported for consumption in Kazakhstan, owners of commercial gas produced outside of Kazakhstan from Kazakhstan raw gas based on international treaties of Kazakhstan (in case of sales of commercial gas to the national operator or in case of exporting and sale out of Kazakhstan), gas distribution organisations (in case of sales of commercial gas to the national operator or owners of vehicle gas filling compressor stations) may participate in the commercial gas wholesale market. When commercial gas is purchased from such persons at the wholesale market, the purchaser cannot further sell such gas at the wholesale market (except for sales by gas distribution companies to the national operator or to owners of the vehicles gas filling compressor stations and sales by the national operator to which such limitation does not apply).

Commercial gas retail sales may only be carried out by:

- gas distribution organisations;
- owners of vehicle gas filling compressor stations; and
- producers of commercial gas, subsurface users who are owners of commercial gas produced in the course of processing of their raw gas, owners of commercial gas produced outside of Kazakhstan and imported for consumption in Kazakhstan, in case of retail sales of commercial gas to industrial consumers whose gas consumption systems are connected directly to a trunk or connecting gas pipeline.

Retail sales of commercial gas must be conducted in accordance with the Retail Gas Sales Rules.[92] Commercial gas may be supplied to consumers' gas consumption systems only by a gas transportation company or a gas distribution organisation.

LPG wholesale and retail markets

LPG wholesales may be carried only by:

- LPG producers;
- owners of LPG produced as a result of processing of their raw hydrocarbons;
- owners of LPG produced outside of Kazakhstan and imported for consumption in Kazakhstan;
- gas network organisations (only in case of LPG sale to owners of gas filling stations or vehicles gas filling stations); and
- owners of LPG purchased from LPG producers and owners of LPG produced as a result of processing of their raw hydrocarbons, beyond the Delivery Plan (outside the electronic trading platforms), for further export and sale out of Kazakhstan.

When LPG is purchased from such persons at the LPG wholesale market, the purchaser cannot further sell such gas at the wholesale market (except for further wholesale by gas network organisations to owners of gas filling stations or vehicle gas filling stations). Under the Gas Law, each gas wholesale transaction of the referred persons in the domestic market effected outside electronic trading platforms must be recorded in the information system of the MoE within ten business days following the transaction date.

LPG may be exported out of Kazakhstan only by LPG producers, owners of LPG produced as a result of processing of their raw hydrocarbons, and purchasers of LPG, if such LPG is purchased beyond the Delivery Plan (outside the electronic trading platforms). LPG wholesale sales may not be effected between gas network organisations.

LPG retail sales may be carried out by gas network organisations, owners of gas filling stations, and LPG producers, owners of LPG produced as a result of processing of their raw hydrocarbons, and owners of LPG produced outside of Kazakhstan and imported for consumption in Kazakhstan (in this case, if the LPG retail sales are to industrial consumers). LPG retail sales must be conducted in accordance with the Retail Gas Sales Rules.

Retail gas sale contracts

Contracts for retail sales of commercial gas and LPG are concluded based on the approved standard form agreements[93] (except for retail sales of commercial gas and LPG to household and industrial consumers, commercial gas by owners of gas filling compressor stations, LPG by owners of gas filling stations, and LPG in household cylinders).

LPG retail sales to consumers through group tank installations (which is a regulated activity in the sphere of natural monopolies) are carried out on the basis of a contract for the retail sales of LPG between a consumer and a gas network organisation to be concluded in the established form.[94]

State regulation of gas prices in the domestic market

As per the Gas Law, the State regulates the wholesale prices of commercial gas in the domestic market and prices of LPG sold in accordance with the Delivery Plan.

Capped prices for the wholesale sale of commercial gas in the domestic market are set annually by the MoE, in coordination with the Natural Monopolies Committee, for the period of 1 July to 30 June of the following year, separately for each region, taking into account the individual economic and social conditions of gas supply to each region. Therefore, for the period of 1 July 2019 to 30 June 2020, the price varies from KZT5,574 to KZT20,819 per 1,000 cubic metres (not including VAT), depending on the region.[95] Such capped prices do not apply to sales of commercial gas to: (a) the national operator when exercising the State's pre-emptive right to purchase gas (for description of the price formation in this case, see below, Purchase of gas by the State); (b) the national operator by owners of commercial gas produced outside of Kazakhstan from Kazakhstan raw gas pursuant to international treaties of Kazakhstan; (c) LNG received in the course of regasification; and (d) raw and commercial gas produced by a subsurface user under a production sharing agreement having a tax stability regime as provided by the Tax Code[96] and providing for the State's pre-emptive right to purchase alienated raw and/or commercial gas.

A capped price for LPG sold in accordance with the Delivery Plan is set quarterly by the MoE, in coordination with the Natural Monopolies Committee. For the period of 1 July 2019 through 30 September 2019, such price is KZT38,701.67 per tonne (not including VAT).[97] Such price does not extend to subsequent sales of LPG by gas network organisations to consumers.

The MoE monitors the production, transportation, storage, shipping and sales of commercial gas, LNG and LPG, including monitoring of wholesale and retail prices of commercial gas, and LNG and LPG in the domestic market. For these purposes, various reports are submitted to the MoE by gas sellers, gas producers/owners, gas transportation and distribution companies, the national operator, and local executive authorities in the manner established by the Gas Law.[98]

The Natural Monopolies Committee does not directly approve, but monitors retail gas prices, being a 'socially significant market', by gas distribution and gas network organisations. Information on such prices is available on the website of the Natural Monopolies Committee.[99] If abuse of power is found, the Natural Monopolies Committee may initiate court hearings resulting in return of payments to the consumers/confiscation of unlawful income received.

Purchase of gas by the State

Under the Gas Law, the State is the owner of associated gas produced in Kazakhstan (under both new production contracts and existing production contracts (including those entered into before the date of the Gas Law), unless they expressly specify that the subsurface user is the owner of the produced gas) and transferred to the State by producers.

The Gas Law[100] provides for the State's pre-emptive right to buy (through the national operator) commercial natural gas and purified raw gas from subsurface users at a price not exceeding the maximum price to be determined according to the rules (and formulas) approved by the MoE.[101] Such price includes production costs, processing costs, transportation costs and profit not exceeding 10%. If the State waives its pre-emptive right to buy gas, the seller may sell the gas to a third party. The procedure of obtaining such waiver must be launched at least five months before the date of the proposed gas supply (sale). The State's pre-emptive right does not extend to the sale of:

- raw gas produced at gas and gas condensate fields and commercial gas produced from such gas;
- LNG and commercial gas received in the process of gas regasification;
- raw gas to be sold as per international treaties of Kazakhstan;
- commercial gas produced outside of Kazakhstan and imported for consumption in Kazakhstan;
- commercial gas produced outside of Kazakhstan from Kazakhstan raw gas under international treaties of Kazakhstan;
- commercial gas produced under an agreement concluded as part of a partnership in the field of gas and gas supply;[102] and
- raw and commercial gas produced by a subsurface user under a production sharing agreement with a tax stability regime as provided by the Tax Code and providing for the State's pre-emptive right to purchase alienated raw and commercial gas.

EAEU common gas market

In May 2014, the EAEU Treaty was signed by the member states, including Kazakhstan (see section A). Chapter XX (Energy) of the EAEU Treaty is dedicated to the matters of cooperation of the member states in the sphere of energy, including through formation of a common gas market and granting access to services of natural monopolies in the gas transportation sector in the member states. Under the EAEU Treaty, the Supreme Eurasian Economic Council approved in May 2016, the concept of forming a common gas market of the EAEU,[103] and in December 2018, the programme of forming a common gas market of the EAEU.[104] Currently, it is anticipated that an inter-state agreement on the common gas market will come into force by 1 January 2025.[105] Formation of the common gas market by the EAEU member states may impact matters related to gas trading in Kazakhstan.

D. Nuclear energy

Legal framework for generation of nuclear energy

Currently, Kazakhstan has no nuclear power generation capacity. Its BN-350 reactor facility (fast neutron sodium-cooled reactor) was the country's only nuclear power reactor, located in Aktau and remaining on the territory of Kazakhstan after the collapse of the Soviet Union, was shut down in 1999 due to financial and technical problems. It was designed and built for electricity generation and seawater desalination for the Aktau region. The BN-350 reactor was commissioned in 1973 and operated for its design life.[106] The decommissioning of the BN-350 reactor started in 1999 and ended in 2010.[107] Kazakhstan has three research reactors at the Republican State Enterprise 'National Nuclear Centre of the Republic of Kazakhstan' in the East-Kazakhstan oblast, and one research reactor at the Republican State Enterprise 'Institute of Nuclear Physics' in Almaty.

The Concept of Development of the Fuel and Energy Sector until 2030 approved in 2014[108] ("Development Concept") provides for development of the nuclear sector, as an alternative energy source. The Government is currently considering building a new nuclear power plant in the Ulken settlement of the Almaty oblast.[109] Development of this facility is envisaged by a Plan of Priority Measures for Construction of Nuclear Power Plants in Kazakhstan approved in 2014.[110] The Plan of Priority Measures also provides for consideration of construction of another nuclear power plant in Kurchatov, in the East-Kazakhstan oblast.

In line with the Development Concept, the legislative framework has recently been adopted. On 12 January 2016, a new Nuclear Energy Law[111] was approved. The Nuclear Energy Law defines the legal basis and principles of regulation of public relations in the sphere of use of atomic energy in order to protect life and health of people, their property and environmental protection, and is aimed at ensuring the regime of non-proliferation of nuclear weapons and nuclear, radiation and nuclear physical safety when using atomic energy.

Under the Nuclear Energy Law, the State, among other things, regulates activity of individuals and legal entities in the sphere of nuclear energy, operations on the territories of former nuclear test sites and nuclear waste storage areas, and training and attestation of personnel in the nuclear energy sector. The MoE, including its Committee for Nuclear and Energy Supervision and Control, is the competent authority in the sphere of nuclear energy.

Article 9 of the Nuclear Energy Law establishes the licensing regime for specific types of activities in the nuclear sector. In addition, the licensed types of activities in the nuclear sector are determined in the Permits and Notifications Law.[112] To obtain a licence, a licensee must meet the approved qualification requirements and submit to the licensing authority documents according to the approved list.[113] The Committee for Nuclear and Energy Supervision and Control of the MoE is the licensing authority.[114]

Under Article 12 of the Nuclear Energy Law, the Government and the local executive authorities adopt decisions regarding construction of new nuclear power plants (facilities) and nuclear waste disposal facilities. In case of a threat to national security, the Government may adopt a resolution to cancel construction of a nuclear power facility or a nuclear waste disposal facility. Article 205 of the current EC stipulates the requirements for location of nuclear power plants. Design, construction and acceptance into operation of a nuclear facility or a nuclear waste disposal facility by legal entities must be conducted in line with the Construction Law,[115] the current EC, the Location Rules[116] and other applicable laws and regulations. Project documentation related to construction is subject to state ecological and sanitary epidemiological expertise. The sanitary epidemiological requirements for radiation safety[117] have been developed in accordance with the Health Code.[118] At the stage of design development for construction of a nuclear power facility or a nuclear waste disposal facility, the operator must develop a preliminary decommissioning plan in line with the approved Decommissioning Rules.[119]

Chapter 39 of the current EC determines ecological requirements for use of radioactive materials; nuclear energy and radiation safety of the population at the place of location and maintenance of nuclear facilities; radiation control, use of radioactive materials, trans-border transportation of radioactive materials and wastes; storage and disposal of radioactive materials and wastes. The Radiation Safety Law[120] is dedicated to principles and matters of radiation safety. It provides that citizens have the right to compensation for harm caused to their life and health, and to compensation for property losses caused by exposure to ionising radiation in excess of the established limits, or as a result of a radiation accident, in accordance with Kazakhstan law. Violation of legislation in the field of radiation safety entails liability established by Kazakhstan law.[121] Under the Radiation Safety Law, in February 2017, certain technical regulations were developed for nuclear and radiation safety, in general, as well as nuclear and radiation safety when operating a nuclear power plant and nuclear research facility.[122]

Under the Nuclear Energy Law, export and import of nuclear and special non-nuclear materials, equipment, installations, technologies, ionising radiation sources, equipment and respective dual use goods and technologies is subject to licensing and export control in the manner established by the Export Control Law.[123] State recording and reporting on nuclear materials and ionising radiation sources are conducted in line with the Nuclear Energy Law and in compliance with the Nuclear Materials Recording Rules.[124]

Under the Nuclear Energy Law, transportation of nuclear materials, radioactive substances and waste is a licensed type of activity. Transportation of nuclear materials, radioactive substances and radioactive waste must be performed in compliance with the approved rules.[125] Collecting, storage and disposal of radioactive waste and spent nuclear fuel must be performed in accordance with the established procedures.[126]

Articles 20 and 21 of the Nuclear Energy Law and the approved qualification and attestation rules[127] stipulate qualification and attestation requirements to personnel involved in operations in the nuclear sector.

Production of uranium

Kazakhstan has the largest uranium reserves in the world. The first commercial deposit in the country (in Korday) was discovered in 1951. Currently, 14 out of 56 known desposits are in use; the remaining 42 are on standby. Kazakhstan has 67% of the world's proven uranium reserves suitable for extraction using in-situ recovery ("ISR") uranium extraction method.[128]

In 2018, the new Subsurface Use Code[129] (including its Chapter VIII (Uranium Production) and Articles 160-184) introduced a special regime for uranium production.[130] Uranium production is conducted based on a production contract concluded with the MoE, as the competent body for uranium production. In general, the MoE represents interests of the State in subsurface use contracts for uranium production and implements the State's policies through development of legal and technical documentation in the sphere of uranium production, regulating and implementing control of subsurface use operations, monitoring compliance of subsurface users with the project documentation and the established rules for purchase of goods, works and services ("GWS") by uranium production companies.

Under Article 160 of the Subsurface Use Code, subsurface use rights for uranium production are granted to the national uranium company (which is currently the 'National Atomic Company Kazatomprom Joint Stock Company' ("Kazatomprom")) based on direct negotiations. Subsurface use rights to uranium production received by Kazatomprom based on direct negotiations may be transferred only to a legal entity, in which Kazatomprom holds, directly or indirectly, 50% and more of shares (participating interests), and the same rule applies to all subsequent transfers of such subsurface use rights.

The concept of the State's pre-emptive right in respect of 'strategic deposits' was transferred from the previously effective legislation into the Subsurface Use Code.[131] In new and previously concluded contracts, the State has a pre-emptive right before third parties (including those having pre-emptive rights under the law or a contract) to purchase a transferred subsurface use right (or its portion) related to a strategic deposit, as well as shares or other securities issued at an organised market, which are 'objects related to subsurface use rights' in respect of strategic deposits. Such transactions require the State's waiver of its pre-emptive right. As per provisions of the Subsurface Use Code, according to which strategic deposits include, among others, uranium deposits, the approved List of Strategic Deposits[132] currently includes 56 uranium deposits. Additionally, a transfer of subsurface use rights for uranium production, as well as the respective objects related to subsurface use rights (for example, shares (participation interests) in the subsurface users and their parent entities, if such shares are not circulated on an organised stock exchange), require obtaining consent of the MoE in the established procedure.

A subsurface use contract for uranium production is concluded in the established form.[133] The maximum term of the initial period of uranium production may not exceed 25 years, including the pilot production period of up to four years. The production period may be further extended by the MoE for a period of up to 25 consecutive years, in the established procedure, at the request of the subsurface user. When conducting operations under a contract for uranium production, a subsurface user must comply with specific requirements of the Subsurface Use Code stipulated, among other provisions, in Chapter 25 (Terms and Conditions of Uranium Production) and Chapter 26 (Project Documents in the Sphere of Uranium Production). Special attention must be given to requirements for calculation and documentation of the produced uranium and productive solutions at leaching (which is a common method for producing uranium in Kazakhstan), compliance with the project documents, rational use of reserves, liquidation of production activity (including requirements to develop a liquidation programme and maintain a liquidation account); financing of the economic development of the region and its infrastructure (in the amount of 1% of investments under the contract during the previous year), training of Kazakhstan employees and scientific research, scientific-technical and research and development works (each in the amount of 1% of expenses for production during the previous year); procurement of GWS; filing reports to the competent authorities (including reports on mineral reserves in compliance with the Kazakhstan Code of Public Reporting, ie the KazRC Code).

The MoE is entitled to unilaterally terminate a contract for uranium production ahead of the expiry date in cases established by law, for example, if the subsurface user fulfils less than 30% of its financial obligations during a year and does not eliminate such violation during three months from the date of receipt of a notification from the MoE on such violation. Also, as per a Government Resolution, the MoE may also unilaterally terminate a contract for uranium production (including a contract concluded before the Subsurface Use Code came into force) if the operations of the subsurface user for uranium production at a strategic deposit leads to a change in economic interests of Kazakhstan, threatening its national security. Article 181 of the Subsurface Use Code establishes liability of subsurface users for breaches of terms and conditions of contracts for uranium production (including penalties to be paid in the amounts to be agreed in the subsurface use contracts).

On 18 May 2018, the new Procurement Rules[134] were approved for uranium production companies, with effect from 29 June 2018. Such Procurement Rules apply to operations under contracts concluded both in accordance with the Subsurface Use Code and in accordance with legislation in effect prior to the introduction of the Subsurface Use Code. The Procurement Rules do not apply to operations of subsurface users that procure GWS under the State procurement rules, and that are legal entities 50% and more of shares of which are owned, directly or indirectly, by the national management holding. The Procurement Rules stipulate that procurement of GWS during uranium production may be effected through: (i) an open tender; (ii) from a single source; (iii) an open slide contest (electronic trades); and (iv) purchase of GWS without taking into consideration certain specific provisions of the Subsurface Use Code,[135] but in accordance with a list of GWS attached to the Procurement Rules.

Kazatomprom

Kazatomprom is the national uranium company established in 1997.[136] It is owned by the State and 75% of its shares are on the List of Strategic Objects;[137] their transfer (sale) would require adoption of a Resolution by the Government. In November 2018, Kazatomprom placed 15% of its shares on the London Stock Exchange and 5% of its shares on the Astana International Exchange, ie AIX, within an initial public offering (IPO) programme.

Importantly, Kazatomprom is Kazakhstan's national operator for export and import of uranium and its compounds, nuclear power plant fuel, special equipment and technologies, and dual use materials.[138]

Kazatomprom has expanded its activities to encompass the entire front-end nuclear fuel cycle production, including enrichment and production of Uranium dioxide powders and fuel pellets. In October 2013, through the Joint Stock Company International Uranium Enrichment Centre and Kazatomprom's joint venture with Russia, Ukraine and Armenia,[139] Kazatomprom became a shareholder of Ural Electrochemical Plant JSC, the largest uranium enrichment enterprise in the world. Ulba (*Ulbinskiy*) Metallurgical Plant JSC ("UMZ"), Kazatomprom's subsidiary located in Ust-Kamenogorsk in the East-Kazakhstan oblast, provides services for the reconversion and production of fuel pellets. For nearly 40 years, UMZ provided services for reconversion and production of uranium dioxide fuel pellets for light water reactors. In addition, Kazatomprom and China General Nuclear Power Corporation (CGNPC) are jointly implementing a project to construct a plant for the production of fuel assemblies based on UMZ for use in Chinese nuclear power plants. It is anticipated that production of fuel assemblies at this new plant will commence by the end of 2020.[140]

Kazatomprom, as the national uranium company, enjoys the benefit of entering into the uranium production contracts with the State based on direct negotiations. This allows Kazatomprom to receive priority access to the high-quality ISR-conducive deposits of natural uranium; 100% of Kazatomprom's production is carried out via ISR extraction of uranium. In addition to production, Kazatomprom conducts geological exploration, with assistance of JSC Volkovgeology, which conducts test drilling of mining sites and other preparatory work for Kazatomprom.

At UMZ, Kazatomprom also produces rare metals and their compounds (such as tantalum-niobioum and beryllium production), which are widely used in instrument making, mechanical engineering, metallurgy, nuclear energy and medicine. Kazatomprom is the only producer in the Commonwealth of Independent States and one of the world's largest enterprises with a complete production cycle from processing of tantalum-niobium-containing raw material to the finished products and has about a 12% share in the global tantalum market.[141] It is one of three companies in the world with a full production cycle of beryllium from ore concentrate processing to finished product.

Bank of low enriched uranium

Kazakhstan is signatory to a number of international and bilateral treaties and a party to various agreements with international agencies related to the nuclear energy industry.[142] Kazakhstan has been fruitfully cooperating with the International Atomic Energy Agency ("IAEA") and has a positive image in strengthening the non-proliferation regime of nuclear weapons.

Under an agreement between the State and the IAEA on the establishment of a bank of low enriched uranium of the IAEA ("LEU Bank") in the State (Astana, dated 27 August 2015 and ratified by the Law[143] dated 22 December 2016), the LEU Bank was created on the territory of UMZ. According to public sources[144] citing the Vice-Minister of Energy of Kazakhstan, it is anticipated that the LEU Bank will commence its work in August 2019. The LEU Bank is needed, primarily, for storage of uranium hexafluoride owned by the IAEA, which can be used for production of fuel for nuclear reactors (if needed). According to Kazakhstan officials,[145] Kazakhstan was chosen for location of the LEU Bank because, among other things, it has a developed system of legislative acts related to export control, licensing, storage and transportation of nuclear materials.

E. Upstream

Terms of exploration and production periods

Legislation does not currently provide for execution of exploration contracts[146] for hydrocarbons but rather, provides for execution of combined E&P contracts that may contain separate periods, ie an exploration period, preparatory period (if necessary) and production period. An exploration period may last for up to six years and up to nine years for offshore contracts and complex projects. These periods may be extended for appraisal of a discovery for up to three years and six years respectively. In addition, at the request of a subsurface user, a preparatory period, which may last for up to three years, may be provided. A production period, which will be reduced for the length of any preparatory period, may last up to 25 years, and in case of large and unique fields for up to 45 years. The term of the production period may be further extended for up to an additional 25 years.

Standard (model) contracts

Drafts of subsurface use contracts must be developed in accordance with standard (model) contracts approved by the competent authority. Deviation from a standard contract is allowed in very limited cases. However, in some cases deviation from the standard contracts may be the basis for the competent authority to demand execution of an entirely new contract. For instance, Article 120.10 of the Code (which applies to hydrocarbons) states that if provisions of a production contract do not comply with a standard contract, upon extension of its term, the parties must enter into an 'amended and restated' production contract that is prepared in accordance with the standard contract.

Ownership structures and the operator

The most common structure for holding E&P rights is a single Kazakhstan or foreign legal entity holding the rights to a concession agreement. Foreign legal entities also commonly hold E&P rights indirectly through ownership in an offshore special purpose vehicle or a Kazakhstan legal entity, which is a party to the concession agreement. E&P rights may be granted to multiple parties in a consortium. Members of such consortium have joint and several liability before the State for the obligations under the concession contract. Such joint holders must appoint an operator and enter into a joint operating agreement, which will regulate their mutual rights and obligations.

Under prior legislation, any member of a consortium could be appointed an operator under the contract. However, the Code prohibits a subsurface user to be appointed as an operator under the same contract. This means that members of the consortium where one of them acted as the operator, can no longer do so and must designate a separate legal entity to serve as the operator of the project.

Strategic partner

Subsurface use rights for certain areas may be provided only to a national company on the basis of direct negotiations. Such rights may be granted to the national company independently or jointly with a strategic partner. A strategic partner is a company (or consortium of companies) that meets the requirements, established by the national company and coordinated with the competent authority, and which has undertaken to carry out investment financing. The Code specifies that investment financing means financing of the exploration costs under an agreement on joint activities or agreement (joint operating agreement) on financing (carry) concluded between a strategic partner and the national company or a company where the national company directly or indirectly owns 50% or more of its shares/interests. The agreement on joint activities must stipulate the obligation of the strategic partner to pay the signature bonus or compensate the amount of the signature bonus to the national company if the latter has paid it.

Land use rights

There are different types of land use rights, including private ownership, leases and easements. Most commonly land use rights are granted on the basis of a resolution of the local authority and a subsequent lease agreement between the local authority responsible for land management and the subsurface user. Lease agreements and any other land use right must be registered with the local justice authorities.

The Code provides that conclusion of a production contract or transfer to a production stage under a combined E&P contract is the basis for granting to the subsurface user land use rights in accordance with the land legislation.

Relinquishment

Historically, the parties agreed a schedule in the subsurface use contract for gradual relinquishment of the contract area. The Code does not require the subsurface user to relinquish any part of the contract area during the exploration or production stage. However, a subsurface user may at any time prior to expiry of a subsurface use contract apply to the competent authority with a request to relinquish part of the contract area. Such request may be satisfied subject to fulfilment of the following conditions by the subsurface user:

- conduct of abandonment works at the relinquished area;
- relinquishment must be done in blocks; and
- if the subsurface use rights are encumbered, prior consent of the pledge holder is obtained.

Upon relinquishment of the contract area or a part thereof the subsurface user must carry out works on liquidation or conservation of objects of subsurface use. Such works will include restoration of land plots and other natural objects damaged as a result of subsurface use operations to a condition suitable for further use. In addition, all industrial facilities of the subsurface use and land plots must be brought into a condition that ensures the safety of life, health of the population and protection of the environment.

Project design documents

Requirements for carrying out prospecting and appraisal, trial production as well as works on development of fields are set out in unified rules for rational and complex use of the subsurface ("Unified Rules").

Subsurface users must carry out subsurface use operations based on a project (design) document that went through expert examinations required under the law and received positive expert conclusions. Subsurface use operations must be carried out in accordance with the following project documents:

- base project documents: exploration plan; project of trial production; project of field development; and
- technical project documents, a list of which is established in the Unified Rules.

Prospecting and appraisal works must be carried out in accordance with the exploration plan. During the exploration period the subsurface user has the right to carry out trial production in accordance with the project of trial production. Production operations must be carried out in accordance with a project of field development, project of trial production or development analysis.

Gas flaring and gas utilisation

As a general rule, gas flaring is prohibited, with limited exceptions, such as:

- for flaring in a threat or emergency, or danger to the life of personnel, health of the population or the environment, no permit is required; however, the authorities must be notified of any emergency flaring within ten days;
- well testing and trial production, subject to obtaining a permit; and flaring of technologically unavoidable gas during start-up and operation of technological equipment and maintenance or repair of technological equipment, all subject to obtaining a permit.

Subsurface users carrying out production of hydrocarbons must take measures aimed at minimisation of gas flaring. The project of field development must contain a section on processing (utilisation) of crude gas.

The production of hydrocarbons without processing of all produced crude gas is prohibited except for gas:

- flared in cases stipulated above;
- used by the subsurface user for own needs in volumes approved by the project document; and
- sold to other persons for processing or utilisation.

At fields where processing of crude gas is not economically justified, the project of field development may stipulate utilisation of all gas (except for gas used for own needs) by injecting into the formation for purposes of storage and/or maintaining reservoir pressure.

Operational licences

Petroleum operators must obtain operational licences and a host of other permits and approvals depending on the specific types of operations. Licences are also required for construction of buildings and facilities. Some of these licences may be held by third party service providers, such as drilling or construction companies.

Additionally, Kazakhstan has a comprehensive permit system. Legislation requires certification of a broad number of products and goods, accreditation for certain laboratories and experts, approvals for personnel, use of certain substances, as well as buildings and constructions of certain designations. There is also a separate special set of permits and approvals for construction activities. Legislation also requires various permits relating to health, safety and labour protection.

F. Renewable energy

F.1 Renewable energy

Main legislation: The Law on Support for the Use of Renewable Energy Sources, which was adopted in 2009 ("Renewables Law"), is the main piece of legislation regulating the use of RES. There is also a number of subordinate acts that regulate the matter, such as rules on conducting auctions, execution and performance of PPA with the FSC, plan for location of RES facilities and list of RES PGOs and a number of others.

Coverage of the Renewables Law: The Renewables Law primarily aims at promotion of 'energy producing companies using RES' ('RES PGOs'), which are defined as legal entities that produce electricity and (or) heat with use of RES. The law further defines RES as follows:

'renewable energy sources shall mean sources of energy which are continuously renewed due to naturally occurring processes, including the following types: solar radiation energy, wind energy, hydrodynamic water energy; geothermal energy: heat of ground, ground waters, rivers, and water bodies; as well as man-made sources of primary power: biomass, biogas and other types of fuel from organic waste, which are used for generating electric and/or thermal energy'.

The Renewable Law also contains provisions on:

- energy producing companies using so called 'secondary energy resources' (ie, energy resources which are originated as auxiliary product of industrial operations related to use of ferroalloy, coke and furnace gases for production of energy); and
- energy producing companies using so called 'waste-to energy' processes.

In most cases, these are regulated similar to RES PGOs.

The Renewables Law envisages special mechanisms for the regulation of prices and for the sale and purchase of electricity and thermal energy produced by RES facilities, connection of RES facilities to the power grid or common heat supply network, and coordination of actions aiming at the construction of RES facilities.

Regulatory bodies: Renewable energy in Kazakhstan is regulated by the Government, the MoE and certain local executive bodies. Further, the FSC has important role in implementation of the state policy on RES promotion as single purchaser of all electricity generated by RES PGOs.

The role of the Government includes:

- development of the main directions of the State policy in the area of use of renewable energy; and
- approval of the fixed tariffs for purchase of electric power produced by RES facilities as well as approval of the rules for defining the fixed tariffs and calculation of the maximum auction price to electric power. Note that fixed tariffs are not applicable for any PPAs entered into after January 2018, the moment of time where all supporting legislation to the July 2017 amendments to the Renewables Law terminating fixed tariff for any new projects were adopted. Fixed tariffs, however, continue to apply for any outstanding PPAs with the FSC entered into before that moment of time.

The principal regulatory body in Kazakhstan with responsibility for renewable energy is the MoE. The role of the MoE as the regulator includes:

- development and approval of regulatory legal acts as well as implementation of the State's policy for support for the use of renewable energy;
- approval of target indicators for development of the RES industry;
- approval of the plan for location of the RES facilities based on the target indicators for development of the RES industry;
- inclusion of auction winners and certain other entities into the list of energy producing organisations; and
- approval of the maximum auction price for purchase of electric power produced by renewable energy facilities.

The local (oblast) executive bodies focus on local support as necessary for implementation of the State's policy in the area of use of renewable energy (eg, reservation and provision of land plots as necessary for RES projects and local coordination of the projects of RES construction).

FSC has central role in procurement from RES PGOs electricity generated by RES facilities and in sale thereof to provisional buyers (as defined below, mainly energy producing companies which use traditional energy sources and nuclear fuel).

Guarantees on procurement of electricity generated by RES facilities: At its choice, RES PGOs may sell electricity to either:

a) RES Centres, which must procure from RES Companies electricity generated by RES facilities and supplied to the unified power system of Kazakhstan. RES Centers must procure electricity using: (i) a fixed tariff, as such is effective as of the date of execution of an agreement between the RES Center and RES Company (fixed tariffs are approved by the Government and annually indexed) or (ii) with use of the auction price, as such is defined based on a performed auction and indexed (indexation order is approved by the Government); or

b) to consumers under direct agreements with buyers of electricity.

RES PGOs may not shift to option (a) after option (b) is chosen.

Guarantees on sale of electricity generated by RES facilities: FSC must sell electricity procured from RES PGOs to the Notional Consumers with use of tariffs for support of RES (this tariff is established by FSC in accordance with the rules approved by the Government). Notional Consumers include all energy producing companies which use traditional energy sources and nuclear fuel, which procure energy from abroad as well as hydropower stations with units located in one group with total capacity above 35MWt (apart from those commissioned after 1 January 2016).

Term of support: FSC executes PPAs with RES PGOs for 20 years (15 years for PPAs entered into before 1 January 2021) from the date of commissioning or from the date of conduct probation that is accompanied by supply of electricity to the Kazakhstan power system.

Fixed tariffs: Fixed tariffs (expressed in KZT/kWh) are established as follows (in all cases excluding VAT): KZT22.68 for wind power plants;[147] KZT70 for solar power plants using photovoltaic ("PV") modules on the basis of Kazakhstan silicon (Kaz PV) of total 37MW capacity; KZT34.61 for other PV converters of solar energy; KZT16.71 for small HPPs; and KZT32.23 for biogas facilities.

Maximum auction prices: Maximum auction prices (expressed in KZT/kWh) are established as follows (in all cases excluding VAT):[148] KZT21.53 for wind power plants; KZT16.96 for PV converters of solar energy; KZT15.2 for HPPs; and KZT32.15 for biogas facilities.

Thermal energy: Local energy supply companies must purchase thermal energy produced and supplied by RES facilities into the heat supply systems of settlements, provided that the thermal energy to be supplied complies with the parameters of the carrying agent of such heat supply system. Expenses related to thermal energy produced by a RES facility should be included in the tariff of an energy supply company in accordance with the legislation on natural monopolies.

Connection: New renewable energy facilities, as well as facilities that have been retrofitted, regardless of the time of their commissioning, must be connected to the nearest point of the power grid or common heat supply network that is suitable in terms of its voltage class or heat carrier parameters.

Energy transmission companies must ensure that renewable energy facilities are capable of being connected and that the nearest point can be established without any impediment and on a non-discriminatory basis.

Where there is any limitation in the transmission capacity of the transmission grids, the energy transmission companies must give priority to the transmission of electricity generated using RES.

The owner of the RES facility incurs the expenses associated with construction of necessary infrastructure (grid or network) for connection of the RES facility with the grid or network of the energy transmission companies as well as with transmission of energy from the RES facility to the point of connection.

Obligations of RES PGOs: During the construction phase, RES PGOs should comply with a number of criteria established by both the Renewables Law and model PPA. Specifically, a RES PGO should, within certain time limits from the execution of PPA, file a notification on commencement of construction and, subsequently, complete the construction, install metering system and conduct testing. During operation phase, RES PGOs must, among other things, comply with the requirements on provision of information to FSC, comply with schedules of electricity generation, operational regimes in accordance with the requirement of the power system operator.

F.2 Renewable pre-qualifications

Auctions for constructing a new RES Facility: A company intending to construct a new RES Facility must participate in an auction. Auctions are conducted electronically by Kazakhstan Operator of Electricity and Power Market JSC. The auctions are conducted in accordance with the approved schedule. Such schedule in certain stances specifies details of the RES facility which should be constructed. However, auctions also may be conducted for construction of a not specified RES facility.

If a RES Facility is specified in the approved schedule, documentation specifying technical details of the planned RES Facility is provided by the auction organiser. If the auction is conducted for the construction of an unspecified RES Facility, the auction is conducted in absence of technical documentation. There are few examples of documentary auctions to date as they require substantial preparation time. Alternately, non-documentary auctions are sometimes ill-prepared which may create issues later for the winners if they are offered land plots and the connection points are not technically suitable or have environmental concerns.

Qualification requirements: Qualification requirements for participation in an auction as well as all details related to organisation and implantation of auctions are established by MoE rules. These rules specify that participants must prove that they have the financial capability and legal capacity.

Financial capability: Financial capability must be proved by a bank guarantee or by a stand-by letter of payment. The amount is to be calculated as follows: (i) if an auction is conducted in absence of the documentation indicating technical details of the planned RES Facility, KZT2,000 (about US$4) should be taken per 1kWt of the power capacity (as stated by the applicant) of the planned RES Facility, (ii) if an auction is conducted in presence of documentation indicating technical details of the planned RES Facility, KZT5,000 (about US$10) should be taken per 1kWt of power capacity of the planned RES Facility as indicated in the schedule.

Legal capacity: Legal capacity is proved by the presentation of corporate documents (such as charter, POAs and registration documents).

Other requirements: Unless an auction announcement indicates a reserved land plot and respective connection point, the participant must also provide documents confirming that it has title to the land plot and technical documents confirming presence of a coordinated point of connection to the existing power lines.

F.3 Biofuel

On 15 November 2010, Kazakhstan adopted the Law on State Regulation of Production and Turnover of Biofuel ("Biofuel Law"). The Biofuel Law defines biofuel as fuel produced from raw materials of biological origin, including bioethanol.

While the production and sale of biofuel are not licensed activities, the Biofuel Law establishes certain criteria for a person intending to produce biofuel. In particular, in order to produce biofuel in Kazakhstan, one has to obtain a passport for the production facility, install equipment to transfer information on the volume of biofuel production to the authorised body for biofuel production (which is the Ministry of Agriculture) and have a facility or installation on the basis of ownership rights or any other property right (eg lease right).

The Biofuel Law also requires entities to have and keep transportation and sale notes for the transportation and sale of biofuel.

The Biofuel Law envisages restrictions on the process of biofuel production and turnover, which includes certain limitations on the use of raw food materials, prohibition to conduct turnovers of alcohol, prohibition to accept genetically modified products as raw materials in the absence of scientific confirmation of safety thereof and in the absence of state registration.

G. Climate change and sustainability

G.1 Climate change initiatives

Government initiatives: Kazakhstan is known for its reserves of oil, gas, uranium, coal and other ore minerals. Notwithstanding this, the Government has realised the benefits of encouraging the development of RES. In 2009, Kazakhstan acceded to the International Renewable Energy Agency Charter.[149] Since 2009, the Government has been adopting and updating legislation to govern the construction and use of RES facilities (in particular the Renewables Law, as discussed above). According to different sources, in 2021 the MoE reported the following data about the share of energy produced/to be produced by RES facilities:

- in 2020 Kazakhstan achieved its first goal of 3%; and
- by or in 2030 Kazakhstan plans to increase this share to 15%.[150]

The MoE also reported that in total 134 RES facilities of 2,010MWt capacity operated in Kazakhstan in 2021.

Furthermore, the Government implements various measures aiming at reduction of emissions, including specifically emission of greenhouse gases ("GHG"). Kazakhstan is a party to the United Nations Framework Convention on Climate Change ("Convention on Climate Change"), which was ratified by Kazakhstan in 1995. Kazakhstan also ratified the Kyoto Protocol to the Convention on Climate Change in 2009 and the Paris Agreement in 2016. The Environmental Code dated 2 January 2021 (effective from 1 July 2021) ("EC") is the main piece of legislation regulating control of emissions, including green-houses gases emissions in the country.

Under the Paris Agreement, Kazakhstan intends to achieve an economy-wide target of 15% (unconditional target) and 25% (conditional target)[151] reduction in GHG emissions by 2030 compared to the base year, which is defined as 1990. The unconditional target of 15% is further stipulated by the EC. According to the available data, 385 million tonnes of carbon dioxide ("CO_2") was emitted in 1990; consequently, no more than 327 million tonnes may be emitted by 2030.

Kazakhstan envisages in the EC a number of high-level measures aiming at the State regulation of climate change. These measures include the following: (i) introducing a definition of 'climate change'; (ii) high-level management measures aiming at the state adaptation to climate change; (iii) the regulation of ozone depleting substances' usage and consumption; (iv) the regulation of emission of GHG substances; and (v) Kazakhstan's input into global response to climate change is established at the level of unconditional target undertaken under the Paris Agreement.[152]

The Ministry of Environment, Natural Resources and Geology is the authorised body that implements state policy on environmental protection, climate change and GHG reduction.

G.2 Emission trading

GHG emissions regulation: The EC's provisions on the state regulation of GHG emissions and absorption (capture) include:

- Establishing a list of the regulated GHGs. The list includes CO_2, methane and other gases.
- There are criteria for defining installations and entities that must obtain GHG emission quotas. These are installations emitting more than the equivalent of 20,000 tonnes of CO_2 per year and working in certain industries, including oil and gas, mining, energy production ("GHG Installation"). Entities operating GHG Installations must obtain quotas.
- There is a National Plan for Carbon Quotas ("National Plan") that establishes the total amount of carbon quotas that may be distributed between the operators of GHG Installations. The responsibility for submitting necessary documents and for obtaining a GHG emissions quota for a specific GHG Installation is with the company that operates the GHG Installation.
- There is a procedure for the distribution of GHG emissions quotas. Additionally, there is a procedure for the amendment of quotas obtained for GHG Installations if the capacity of such installations increase.
- The system of carbon offset is established to promote the reduction of GHG emission and increase of GHG capture (absorption). The projects aiming at the reduction of GHG emission and increase of GHG capture (absorption) are coordinated with the environmental authority.

GHG emissions trading: Carbon unit definition is introduced. A carbon unit is equivalent to one tonne of CO_2. Carbon units include both carbon units obtained as quotas for GHG Installations as well as carbon units obtained as a result of the implementation of carbon offset projects.

Trading by carbon units is permitted. Companies that operate GHG installations, companies and individuals that implement carbon offset projects and an 'operator of the system of carbon units trading' ("Trading Operator"), which is a subordinate of the Ministry of Environment, Natural Resources and Geology, may participate in trading. There is no approved list of commodity markets that may be used for trading carbon units.

G.3 Carbon pricing

Data on carbon pricing is limited. According to the data from Kaspiy Commodity Market, in 2014-2015 there were 75 transactions on sale of carbon units conducted at the Kaspiy Commodity Market. Total value of these transactions was KZT936,824,603 (about US$6.2 million). The weighted average price was KZT287.79 (about US$1.5). There is no data for the period from 2016 to 2020. According to the data from Kaspiy Commodity Market, the weighted average price in 2021 was KZT500 (about US$1.2). There is no publicly available data for 2022.

G.4 Capacity markets

See power capacity market above, in sections A.3 and A.4.

H. Energy transition

H.1 Overview

In terms of reducing carbon and other GHG emissions and achieving carbon neutrality by 2050, Kazakhstan is at a foundational stage. The list below features what Kazakhstan has done and what remains to be done:

- Kazakhstan has successfully started the implementation of RES (see Section F for more detail). However, 2021 and 2022 represented a decrease in new auctions for RES PGOs. This is primarily due to the lack of cycling power to balance the natural intraday imbalances for solar and wind facilities. To address the issue, at the end of 2020 Kazakhstan's Parliament adopted amendments to the Electricity Industry Law, introducing specific regulation for newly commissioned generating facilities with a cycling regime. These are gas or hydro power stations that can quickly and substantially change generated power. These facilitates compensate for changes in generated power and changes in the electrical load in the other parts of the grid. The Rules on the Inclusion of Customers into the List of Power Stations issued by the MoE on 30 April 2020 and the Rules on Organisation and Conducting Auctions on Construction of Newly Commissioned Generating Facilities with Cycling Regime dated 30 April 2021 determine, in more detail, the requirements for regulating power capacity which is at a capacity range within which the service provider can produce electricity subject to established parameters. After many delays in implementing the amendments, two auctions were held in July 2022, both in the South zone. One auction was for a combined cycle gas turbine with heat production of 240MWt capacity and the other for a combined cycle gas turbine of 926.5MWt capacity. If both projects are successfully completed, two power plants would substantially increase capacity of the national energy system to absorb more RES facilities.
- The recently adopted Environmental Code has the clear commitment written in the body of law to meet Kazakhstan's international obligation under the Paris Agreement and achieve an economy-wide target of a 15% (unconditional target) reduction in GHG emissions by 2030. Despite the lack of clarity on how to achieve this goal, the statement should be observed in any subordinate legal act.
- The recently adopted Environmental Code introduced a concept of best available technologies which all companies should gradually start using under the threat of increased environmental fees and very substantial fines. The primary purpose of best available technologies is to reduce pollution, an acute problem for Kazakhstan due to its substantially outdated industry. However, best available technologies would also be useful in GHG reduction. The biggest obstacle to the best available technologies is a lack of investment (for internal producers, for example coal generators) and the threat of prices becoming non-competitive on export markets (for example, steel producers).
- Kazakhstan has a workable system of internal carbon quota trading, including infrastructure and supporting legislation (see section G). However, due to a lack of investments to upgrade GHG emitters and buy carbon units (the biggest are coal generators with fixed electricity tariffs and unsatisfactory capacity market), the Government must issue substantial amount of carbon units without payment. This limits the incentives for the development of carbon units trading, including the development of clean facilities which may generate and sell carbon units on the market.
- There is a relatively good Energy Efficiency Law and supporting legislation that aim to increase energy efficiency in all sectors of the economy (see section A). However, relatively cheap electricity does not provide enough stimulus for costly measures to, for example, decrease losses in the national grid.
- There are active discussions in Kazakhstan regarding the need to increase electricity tariffs which have mostly been frozen for several years. The recent suggestion of the Agency on Protection and Development of Competition, and supported by President Tokayev, is to gradually increase tariffs for the population and decrease tariffs for general businesses (note that most large-scale businesses have intra-group generation and do not sell or buy electricity on the market) while simultaneously subsidising low-income populations. There are also discussions on introducing a unified purchaser of electricity for retail purposes which would decrease disbalances on the retail market and increase returns for PGOs. If successful, the measure may increase the money available for the renovation/construction of PGOs and meeting of energy transition targets.

H.2 Renewable fuels

Kazakhstan has no industry operating with green hydrogen, blue hydrogen or with ammonia; there is no legislation specifically addressing renewable fuels of this type. There are discussions between potential producers and the State, however, according to publicly available information, no binding documents have been signed. In terms of available resources, Kazakhstan has good prospects for installing PV or small hydropower plants to provide electricity to produce green hydrogen. However, the production of green hydrogen requires substantial amounts of water and most of Kazakhstan features dry areas. The production of blue hydrogen may be less beneficial, as Kazakhstan lacks substantial and available amounts of gas.

H.3 Carbon capture and storage

Provisions in the EC, which regulates GHG emissions, also addresses the absorption (capture) of GHGs. In particular, the mechanism for trading carbon units applies to carbon units not only for reducing emissions, but also, among other things, for the absorption (capture) of GHGs. Furthermore, there are rules that establish an order for the implementation of projects that aim at regulating emissions and also the capture (absorption) of GHGs.

H.4 Oil and gas platform electrification

There is currently no oil and gas platform electrification in Kazakhstan.

H.5 Industrial hubs

Kazakhstan has two types of industrial hubs: special economic zones (“SEZ”) and industrial zones (“IZ”). SEZ is defined as a part of the territory of the State limited by exact boundaries which have a SEZ legal framework for the implementation of priority activities.[153] SEZ legal framework includes offering land plots for locating facilities, income, property and land use tax benefits.[154] Additionally, certain SEZ have a free economic zone customs regime. Priority activities vary between zones, as outlined by a specific (per each zone) Government resolution establishing a given SEZ and generally including modern high-performance competitive industrial facilities, new technologies or activities aimed to increase employment. The authorised body (currently, the Ministry of Industry and Infrastructure Development and its predecessor, the Ministry of Investments and Development ("MI&D")) based on the Government resolutions approves a detailed list of priority activities for all zones. Currently, this is the list approved by MI&D resolution no. 142 dated 27 February 2018, as amended. The list contains some general language permitting most of the SEZ to deal with production of equipment for RES PGOs or energy efficiency equipment; however, neither SEZ is specifically engaged in such activities. A SEZ is established for a term of up to 25 years and the term may be extended.

An applicant may establish a company in a SEZ if it has sufficient funding and if its proposal fits the types of activities intended to be performed in the SEZ. The following entities cannot apply for the establishment of an SEZ: subsurface users, manufacturers of excisable goods, with some exceptions, entities that already enjoy certain investment related benefits (tax relief under a special tax regime, investment tax preferences under investment contracts entered into before 1 January 2009, benefits for investment priority and strategic investment projects), and entities engaged in gambling.

IZ is an area equipped with engineering and communication infrastructure to be provided to legal entities for the placement and exploitation of the products of entrepreneurial activity, including the production sector, agricultural complex, the tourist industry, transportation logistics and waste management. An IZ that attracts state funds for its development is created by a decision of the respective territorial state executive body on the basis of a positive conclusion of a state authorised body. A state funded IZ is created for a term of not less than 20 years and the term may be extended. Companies work in an IZ on the basis of an agreement on conducting activity entered into with IZ management company. Such an agreement provides for access to infrastructure and land plots in exchange for the implementation of an agreed project within agreed terms.

Currently, Kazakhstan has 13 SEZ and 24 industrial zones. SEZs are often criticised by top state officials for being inefficient. Commentators say that only a number of economic zones, in particular 'Astana – New City', 'Ontustyk', 'Pavlodar' and, possibly, 'Khorgos – East Gate' are relatively successful. Others either have very few participants or have uncompleted infrastructure. To give an additional impulse for the development of SEZ, the authorised state body recently announced the amendments to SEZ legislation whereby the companies resident in SEZ may undertake activities not listed in the EZ charter documents (but without tax benefits available for charter activities only). Public information on IZ performance is unavailable.

H.6 Smart cities

A 'smart City' is the introduction of 'smart' technologies into citizens lives to improve the efficiency of city services and the comfort of living in the city. The project is one of the indicators of the Digital Kazakhstan program. The key areas where new technologies are being introduced were security, housing and communal services, transport, automation of public services, as well as education and healthcare. Nur-Sultan, Almaty, Aktobe and Petropavlovsk were selected as the first cities for the 'pilot'.

In 2017, the concept of sustainable development of the capital 'Smart Astana' was created, which was supposed to solve the main problems of the city through the introduction of 'smart' technologies in two directions: the management of urban resources and services and the improvement of infrastructure.

Currently, the Development Concept of Smart Astana for the next five years is being developed.

At the end of 2020, Smart Astana and Smart Almaty entered the world ranking of smart cities including MERCER, UN Local Online Service Index and Innovation Cities Index.

I. Environmental, social and governance (ESG)

The EC envisages a strategic environmental assessment ("SEA") as a mandatory pre-requisite for implementation of the state programmes aiming at the development of agriculture, forestry, fishery, industry (including exploration and production of minerals), energy, transportation, waste management, water management and some others. SEA is a procedure that starts at the early stages of the state programmes development. An SEA report must include an assessment of environmental, social and economic impacts of the proposed state programme. Furthermore, an environmental impact assessment is a mandatory procedure that must precede construction of a particular industrial facility. Environmental impact assessments must also include an assessment of the social and economic impacts of a proposed development.

In 2021, Kazakhstan's legislation was developed to cover social entrepreneurship. The Entrepreneurship Code was added by the provisions on social entrepreneurship in June 2021. Social entrepreneurship relates to business activities that aim to promote the employment of certain categories of people (socially vulnerable), the sale of goods, work and services performed by socially vulnerable groups and the production of goods, work and services that are of need for the socially vulnerable population groups. The state maintains a register of the business entities that perform social entrepreneurship and guarantees special measures for supporting business entities that are involved in social entrepreneurship. Such measures include tax incentives, grants, preferential lease of the state property and other measures.

Endnotes

1. See www.kegoc.kz/en/power-industry/kazakhstan-electric-power-industry-key-factor.
2. Financial Settlement Center for Renewable Energy LLP (*товарищество с ограниченной ответственностью "Расчетно-финансовый центр по поддержке возобновляемых источников энергии*", see official website www.rfc.kegoc.kz ("FSC"), which is established by KEGOC and appointed by the Ministry of Energy to serve as the centralised purchaser of services at the capacity market (by Order no. 357 of the Minister of Energy, dated 7 September 2018) and the settlement and financial centre for the support of RES (by Order no. 256 of the Minister of Energy, dated 31 March 2015).
3. The MIID is responsible for the state control (supervision) of the technical regulations pursuant to the Governmental Resolution no. 296, dated 17 May 2019.
4. Reference is made to the Land Code of the Republic of Kazakhstan (no. 442-II, dated 20 June 2003, as amended) ("Land Code").
5. Joint-Stock Company "Kazakhstan Electricity and Power Market Operator" (*Акционерное общество "Казахстанский оператор рынка электрической энергии и мощности*", (KOREM JSC/*АО "КОРЭМ"*), see official website www.korem.kz) ("KOREM"), appointed as the operator of the centralised trading market by Order no. 226 of the Minister of Energy, dated 20 March 2015.
6. Appointed as the RES auction organiser by Order no. 280 of the acting Minister of Energy, dated 7 August 2017.
7. Kazakhstan Centre for Modernisation and Development of Housing and Communal Services JSC (*Акционерное общество "Казахстанский центр модернизации и развития жилищно-коммунального хозяйства"* or *АО "Казцентр ЖКХ"*) ("Kazcenter HCS"), see official website www.zhkh.com.kz.
8. Appointed by Governmental Resolution no. 740 dated 3 September 2015.
9. Institute of Development of Electricity Industry and Energy Saving (*Kazakhenergoexpertiza*) JSC ("KazEnergoExpertise") appointed by Order no. 1130 of the Minister of Investments and Development of the Republic of Kazakhstan dated 30 November 2015.
10. Reference is made to the Law of the Republic of Kazakhstan "On Electricity Industry" (no. 588-II, dated 9 July 2004, as amended) ("Electricity Industry Law").
11. Reference is made to the Law of the Republic of Kazakhstan "On Natural Monopolies" (no. 204-VI, dated 27 December 2018) ("Natural Monopolies Law").
12. Referring to the Code of the Republic of Kazakhstan "The Entrepreneurial Code of the Republic of Kazakhstan" (no. 375-V, dated 29 October 2015, as amended) ("Entrepreneurial Code").
13. The Law of the Republic of Kazakhstan "On Support of Use of Renewable Energy Sources" (no. 165-IV, dated 4 July 2009, as amended) ("Renewables Law").
14. Referring to the Law of the Republic of Kazakhstan "On Energy Saving and Energy Efficiency" (no. 541-IV, dated 13 January 2012, as amended) ("Energy Efficiency Law").
15. The standard form services contracts for: (i) technical dispatching of supply to the grid and consumption of electrical energy; (ii) transmission of electrical energy through the national power grid network; (iii) organisation of balancing production and consumption of electricity; and (iv) transmission and/or distribution of electricity are approved by Order no. 266 of the Minister of the National Economy dated 27 March 2015.
16. Approved by Order no. 356 of the Minister of Energy dated 23 October 2017.
17. Reference is made to the Law of the Republic of Kazakhstan on Architecture, Urban-Planning and Construction Activity in the Republic of Kazakhstan (no. 242-II, dated 16 July 2001, as amended) ("Construction Law").
18. Reference is made to Articles 14.5 and 14.6 of the Electricity Industry Law.
19. Reference is made to Article 15.23 of the Natural Monopolies Law.
20. Reference is made to the Rules of conducting activity by the natural monopolies approved by Order no. 256 of the Minister of Industry and Infrastructure Development dated 30 April 2019 ("Natural Monopolies Operating Rules").
21. Reference is made to the Rules for granting equal conditions of access to regulated services (goods, works) in the field of natural monopolies approved by Order no. 175 of the Ministry of National Economy dated 29 December 2014 (as amended) ("Equal Access Rules").
22. Referring to the Power Grid Rules approved by Order no. 210 of the Minister of Energy dated 18 December 2014 (as amended) ("Power Grid Rules").
23. Reference is made to the Rules for determining the nearest point for connecting to electric and heat power networks and access by the RES facilities, approved by the Ministry of Energy Resolution no. 117, dated 20 February 2015, as amended ("Access Rules").
24. Reference is made to the Rules of organisation and functioning of the wholesale electricity market approved by Order no. 106 of the Minister of Energy dated 20 February 2015, as amended ("Wholesale Market Rules").
25. Reference is made to the Rules of organisation and functioning of the retail electricity market approved by Order no. 111 dated 20 February 2015, as amended ("Retail Market Rules").
26. Reference is made to the Rules of functioning of the balancing market of electricity approved by Order no. 112 of the Minister of Energy dated 20 February 2015, as amended ("Balancing Market Rules").
27. Reference is made to the Rules of organisation and functioning of the capacity market approved by Order no. 152 of the Minister of Energy, dated 27 February 2015 (as amended) ("Capacity Market Rules").
28. Reference is made to the standard form contracts approved by Orders nos. 683 and 684 of the Minister of Energy dated 3 December 2015 (as amended), and Order no. 512 of the Minister of Energy dated 14 December 2018.
29. Currently, standard forms for PPAs and NC PPAs are approved by Order no. 480 of the Ministry of Energy, dated 28 December 2017.
30. Such Notional Consumers include: (a) the PGOs using coal, gas, oil products, sulphur-containing raw materials and nuclear fuel; (b) the energy market participants importing electric energy; and (c) the hydroelectric power stations with the units located within one hydroelectric complex with the capacity exceeding 35MW (except for those constructed after 1 January 2016).
31. According to Order of the Natural Monopolies Committee (no. 67-ОД, dated 22 April 2022) both available at www.kegoc.kz/ru/about/deyatelnost-kompanii/tarify. KEGOC is disputing the Order in court and, if challenge is successful tariffs may be substantially higher.
32. Rules of calculation of the service fee are approved by Order no. 685 of the Minister of Energy dated 3 December 2015.
33. The information on the tariff is available at the FSC's website, see www.rfc.kegoc.kz/page/powerprice.
34. Pursuant to Order no. 261 of the Minister of Energy dated 30 September 2005.
35. In accordance with the motivated conclusion no. 38-1826/9393 on reducing the projected price for the service to ensure the readiness of the trading system to conduct centralised trading in electric energy dated 17 July 2015, available at www.korem.kz/rus/kak_torgovat/uslugi.
36. Information on KOREM's tariffs is available at www.korem.kz/rus/kak_torgovat/uslugi.
37. Reference is made to Order no. 514 of the Ministry of Energy dated 14 December 2018.
38. The PGOs groups are approved by Order no. 476 of the Minister of Energy dated 5 December 2018.
39. Approved by Order no. 465 of the Minister of Energy, dated 3 July 2015, as amended.
40. Picture 6.10 in the 2021 National Energy Report prepared by KazEnergy in conjunction with HIS Markit with the support of state authorities and major energy companies, available at www.kazenergy.com/upload/document/energy-report/NationalReport21_ru_2.pdf (the "National Energy Report").
41. See www.kremzk.gov.kz/rus/menu2/tarify_srt/tarify_sozr/elektroenergiya.
42. Reference is made to Article 7-1 of the Electricity Industry Law.
43. Reference is made to the Law of the Republic of Kazakhstan on Permits and Notifications (no. 202-V, dated 16 May 2014, as amended) ("Permits and Notifications Law"), including Annex 1 thereto.
44. Approved by Order no. 60 of the Minister of the National Economy dated 29 January 2015.

45. Reference is made to provisions of Article 35.1 of the Permits and Notifications Law.

46. The State Service Rules "Issuance of a License on Activity of Sale and Purchase of Electric Energy for Power Supply Purpose" are approved by Order no. 47 of the Minister of the National Economy dated 5 June 2020.

47. Reference is made to a monthly calculated index approved by budget laws for calculation of taxes and other payments to the budget ("MCI"). Currently, 1 MCI equals to KZT3,063.

48. Reference is made to the procedure approved by Order no. 686 of the Minister of Energy dated 3 December 2015 (as amended).

49. Reference is made to the procedure approved by Order no. 355 of the Minister of Energy dated 23 October 2017.

50. Reference is made to the Rules of conducting qualification examinations approved by Order no. 210 of the Minister of Energy dated 18 March 2015, as amended.

51. See Article 20 of the Electricity Industry Law.

52. See Order no. 58 of the Minister of Energy on Approval of the Rules on Prevention of Emergencies in Kazakhstan Unified Power System and Their Liquidation dated 2 February 2015.

53. See Article 21 of the Electricity Industry Law.

54. See Order no. 75 of the Minister of Energy dated 11 February 2015 (as amended).

55. Reference is made to Articles 13-16 of the Energy Efficiency Law.

56. Reference is made to Article 8 of the Energy Efficiency Law.

57. Reference is made to Article 18-1 of the Energy Efficiency Law.

58. Reference is made to the form energy service agreements approved by Order no. 402 of the Minister of Investments and Development of the Republic of Kazakhstan, dated 31 March 2015, as amended.

59. For description of examples of such projects see www.almaty.tv/news/arkhiv/135926-umnye-schyotchiki-tepla-i-goryachey-vody-ustanavlivayut-v-almaty and www.inform.kz/ru/umnye-kvartirnye-schetchiki-testiruyut-v-petropavlovske_a3448132.

60. For more information see the website of Kazcenter HCS www.zhkh.com.kz.

61. Reference is made to the Unified Commodity Nomenclature of Foreign Economic Activity of Eurasian Economic Union and Unified Customs Tariff of Eurasian Economic Union adopted by the Decision of the Council of the Eurasian Economic Commission No. 80 of 14 September 2021, as amended.

62. Reference is made to Chapter 13 of the Tax Code and the response of the Chairman of State Revenues Committee dated 4 August 2020 No. 628318/1 (dialog.egov.kz).

63. Reference is made to the Methodology of Calculation of Utilisation Fee approved by the Order No. 448 of the Minister of Ecology, Geology and Natural Resources on 2 November 2021, as amended.

64. The Law of the Republic of Kazakhstan on Automobile Transport (no. 476-II, dated 4 July 2003, as amended) ("Automobiles Law").

65. Approved by Order no. 197 of the acting Minister of Investments and Development dated 26 November 2014.

66. Ie the technical regulation TR CU 018/2011, approved by Resolution no. 877 of the Commission of the Customs Union dated 9 December 2011 (as amended).

67. Law No. 86-VII "On Industrial Policy" dated 27 December 2021.

68. Approved by the Order No. 303 of the Minister of Industry and Infrastructure Development dated 30 May 2022.

69. Adopted by the Law No. 375-V dated 29 October 2015.

70. The Environmental Code of the Republic of Kazakhstan (no. 400-VI, dated 2 January 2021, as amended) ("Environmental Code").

71. Reference is to the Classification of 'green' projects approved by Government Resolution No. 996 dated 31 December 2021.

72. For more discussion in this paragraph, see Section 6 of the 2021 National Energy Report.

73. Referring to Article 10 of the Electricity Industry Law.

74. Including the Rules of provision of services to ensure reliability and sustainability of power supply (approved by Order no. 72 of the Minister of Energy of the Republic of Kazakhstan, dated 11 February 2015) and the Rules of provision of services by the system operator, organisation and functioning of the market of system and support services (approved by Order no. 691 of the Minister of Energy of the Republic of Kazakhstan, dated 3 December 2015).

75. Reference is made to the Treaty on the Eurasian Economic Union (signed in Astana on 29 May 2014, as amended; and ratified by Kazakhstan by Law no. 240-V of the Republic of Kazakhstan, dated 14 October 2014). Currently, the Republic of Armenia, the Republic of Belarus, the Republic of Kazakhstan, the Kyrgyz Republic and the Russian Federation are members of the EAEU. For more information regarding the EAEU see www.eaeunion.org.

76. Decision no. 12 of the Supreme Eurasian Economic Council dated 8 May 2015, available at www.eurasiancommission.org.

77. Decision no. 20 of the Supreme Eurasian Economic Council dated 26 December 2016, available at www.eurasiancommission.org.

78. Law of the Republic of Kazakhstan on Natural Monopolies dated 27 December 2018.

79. Except for their transportation for purposes of transit through the territory of Kazakhstan and export outside Kazakhstan.

80. The Code of the Republic of Kazakhstan on Subsurface and Subsurface Use (no. 125-VI ZRK) dated 27 December 2017, which came into force on 29 June 2018.

81. The new ministry was created by the Edict of the President dated 17 June 2019.

82. The Law of the Republic of Kazakhstan on Main Pipelines dated 22 June 2012, as amended.

83. Except for storage, transportation of commercial gas for purposes of transit through the territory of Kazakhstan and export outside Kazakhstan.

84. The Law of the Republic of Kazakhstan on Gas and Gas Supply dated 9 January 2012, as amended.

85. CRNM, Protection of Competition and Consumers Rights of the Ministry of National Economy of the Republic of Kazakhstan.

86. Products are defined in the Pipelines Law as oil, including stable and unstable gas condensate, natural gas, associated gas, other liquid and gaseous hydrocarbons as well as petroleum products.

87. See www.primeminister.kz/en/news/v-neftyanoy-otrasli-po-itogam-2021-goda-obem-dobychi-nefti-ozhidaetsya-na-urovne-857-mln-tonn-minenergo-22111737.

88. See www.kapital.kz/economic/78272/k-2040-godu-potreblenie-gaza-v-kazahstane-mozhet-prevysit-31-mlrd-kubometrov.html and www.kaztransgas.kz/index.php/ru/press-tsentr/publikatsii/1561-k-2040-godu-potreblenie-gaza-v-kazakhstane-mozhet-prevysit-31-mlrd-kubometrov.

89. Reference is made to the Law of the Republic of Kazakhstan on Gas and Gas Supply (no. 532-IV, dated 9 January 2012, as amended from time to time) ("Gas Law").

90. Under the Gas Law, commercial gas (*tovarniy gas*) is a multicomponent mixture of hydrocarbons with a predominant methane content, which: (i) is in a gaseous state; (ii) is a product of raw gas processing; and (iii) meets the requirements of technical regulations and national standards for the qualitative and quantitative content of components.

91. Reference is made to the Rules of organising and conducting LPG trading through electronic trading platforms approved by Order no. 481 of the Minister of Energy dated 6 December 2018 ("LPG Electronic Trading Rules").

92. Reference is made to the Rules of the Retail Sales and Use of the Commercial and Liquefied Petroleum Gas approved by Order no. 96 of the Minister of Energy, dated 3 November 2014, as amended ("Retail Gas Sales Rules").

93. Reference is made to the standard form agreements approved by Order no. 117 of the Minister of Energy, dated 12 November 2014.

94. The standard form agreement is approved by Order no. 266 of the Minister of National Economy dated 27 March 2015.

95. According to Order no. 169 of the Minister of Energy dated 13 May 2019.

96. Reference is made to Article 722 of the Code of the Republic of Kazakhstan on Taxes and Other Mandatory Payments to the Budget (Tax Code), no. 120-VI dated 25 December 2017 (as amended) ("Tax Code").

97. According to Order no. 216 of the Minister of Energy dated 12 June 2019.

98. Reference is made to requirements of Article 21 of the Gas Law.

99. See www.kremzk.gov.kz/rus/menu2/tarify_srt/tarify_sozr/gaz.

100. Reference is made to Article 15 of the Gas Law.

101. Reference is made to Order no. 121 of the Minister of Energy dated 13 November 2014 (as amended).

102. Such partnership is available pursuant to the terms and conditions of transfer of associated gas to investors within framework of partnership in the field of gas and gas supply, approved by Order no. 162 of the Minister of Energy dated 28 November 2014.

103. Decision no. 7 of the Supreme Eurasian Economic Council dated 31 May 2015, available at www.eurasiancommission.org.

104. Eurasian Commission reference to Decision no. 16 of the Supreme Eurasian Economic Council dated 6 December 2018. See www.eurasiancommission.org.

105. According to a report of the Division of the Oil and Gas Policy under the Energy Department of the Eurasian Economic Commission, available, as of 4 June 2019, at www.eurasiancommission.org.

106. See the 2016 Report of the IAEA, available at www.cnpp.iaea.org/countryproviles/Kazakhstan/kazakhstan.htm.

107. According to the Environmental Performance Reviews: Kazakhstan (Third Review) of the United Nations Economic Commission for Europe, dated 2019, available at www.unece.org/fileadmin/DAM/env/epr/epr_studies/ECE.CEP.185.Eng.pdf.

108. Approved by the Governmental Resolution no. 724, dated 28 June 2014.

109. See www.tengrinews.kz/kazakhstan_news/mesto-pod-stroitelstvo-aes-opredelili-v-almatinskoy-oblasti-366452.

110. Approved by Order no. 60-p of the Prime Minister of the Republic of Kazakhstan, dated 4 May 2014.

111. The Law of the Republic of Kazakhstan on Use of Atomic Energy (no. 442-V, dated 12 January 2016, as amended, and effective from 25 January 2016) ("Nuclear Energy Law").

112. The Law of the Republic of Kazakhstan on Permits and Notifications (no. 202-V, dated 16 May 2014, as amended) ("Notifications and Permits Law").

113. The qualification requirements and a list of documents were approved by Order no. 122 of the Minister of Energy, dated 13 November 2014 (as amended).

114. Pursuant to the Governmental Resolution no. 274 dated 23 April 2015.

115. The Law of the Republic of Kazakhstan on Architecture, Urban-Planning and Construction Activity in the Republic of Kazakhstan (no. 242-II, dated 16 July 2001, as amended) ("Construction Law").

116. Reference is made to the Rules of Choosing a Site for Location of Nuclear Facilities and Nuclear Disposal Facilities approved by the Governmental Resolution no. 301 dated 24 May 2016 ("Location Rules").

117. Reference is made to the sanitary rules approved by Order no. 261 of the acting Minister of National Economy of the Republic of Kazakhstan, dated 27 March 2015.

118. The Code of the Republic of Kazakhstan on Population's Health and the System of Health Care (no. 193-IV, dated 18 September 2009, as amended) ("Health Code").

119. Reference is made to the Rules of Decommissioning of Nuclear Facilities and Radiation Installations approved by the Governmental Resolution no. 287, dated 12 May 2016 ("Decommissioning Rules").

120. Reference is made to the Law of the Republic of Kazakhstan on Radiation Safety of Population, no. 219-I dated 23 April 1998, as amended ("Radiation Safety Law").

121. Reference is made to penalties stipulated by Articles 413-414 of the Code of the Republic of Kazakhstan on Administrative Violations (no. 235-V, dated 5 July 2014, as amended) and sanctions to be imposed pursuant to the Criminal Code of the Republic of Kazakhstan (no. 226-V, dated 3 July 2014, as amended).

122. Referring to the technical regulations approved by Orders nos. 58, 59 and 60 all approved by the Minister of Energy on 20 February 2017.

123. The Law of the Republic of Kazakhstan on Export Control (no. 300-III, dated 21 July 2007, as amended) ("Export Control Law").

124. Reference is made to the Rules of State Recording of Nuclear Materials approved by Order no. 44 dated 9 February 2016 (as amended) ("Nuclear Materials Recording Rules").

125. Reference is made to the Rules of Transportation of Nuclear Materials and the Rules of Transportation of Radioactive Substances and Radioactive Wastes approved by Orders no. 76 and no. 75 of the Minister of Energy both dated 22 February 2016, respectively.

126. We refer to the Rules of Collecting, Storage and Disposal of Radioactive Wastes and Spent Nuclear Fuel approved by Order no. 39 of the Minister of Energy of the Republic of Kazakhstan dated 8 February 2016.

127. Reference is made to the Rules of Attestation of Personnel Involved in Operations at a Nuclear Facility and the Rules of Upgrading Qualification of Personnel Involved in Operations at a Nuclear Facility approved by Orders no. 12 and no. 13 of the Minister of Energy both dated 20 January 2016, respectively.

128. Based on information available at the official web of Kazatomprom, see www.kazatomprom.kz/en/page/geologorazvedka.

129. Reference is made to the Code of the Republic of Kazakhstan on Subsurface and Subsurface Use (no. 125-VI, dated 27 December 2017, as amended, and effective as of 29 June 2018) ("Subsurface Use Code").

130. Certain transitional provisions of the Subsurface Use Code may apply to subsurface use contracts concluded prior to the introduction of the Subsurface Use Code.

131. For reference, see Article 43 of the Subsurface Use Code.

132. Reference is made to a list of strategic deposits approved by the Governmental Resolution no. 389, dated 28 June 2018 ("List of Strategic Deposits").

133. A form contract for uranium production is approved by Order no. 233 of the Ministry of Energy of the Republic of Kazakhstan on Approval of Form Subsurface Use Contracts, dated 11 June 2018.

134. Reference is made to the Rules of procurement by subsurface users and their contractors of goods, works and services, used at operations for exploration and production of hydrocarbons and uranium production, approved by Order no. 196 of the Minister of Energy of the Republic of Kazakhstan, dated 18 May 2018 and effective as of 29 June 2018 ("Procurement Rules").

135. Namely, without taking into consideration sub-paragraphs 1), 2) and 3) of Article 179.1 of the Subsurface Use Code, including, for example, provisions regarding a 20%-reduction in price of a bid for bidders who are Kazakhstan producers.

136. By Edict no. 3593 of the President of the Republic of Kazakhstan.

137. Reference is made to a list of strategic objects approved by Governmental Resolution no. 651, dated 30 June 2008 (as amended) ("List of Strategic Objects").

138. Based on the Governmental Resolution no. 1659 dated 26 November 1997, as amended.

139. See www.eng.iuec.ru.

140. See www.kazatomprom.kz/en/page/produktsiya_yatts.

141. Based on information available at the official website of Kazatomprom, see www.kazatomprom.kz/en/page/redkie_matalli.

142. For a list of international treaties, see, for example, Annex II to the Environmental Performance Reviews: Kazakhstan (Third Review) of the United Nations Economic Commission for Europe, dated 2019 and available at www.unece.org/fileadmin/DAM/env/epr/epr_studies/ECE.CEP.185.Eng.pdf.

143. Reference is made to the Law of the Republic of Kazakhstan on Ratification of an Agreement between the Republic of Kazakhstan and the International Atomic Energy Agency on Establishment of a Bank of Law Enriched Uranium of the International Atomic Energy Agency in the Republic of Kazakhstan (no. 31-VI ZRK, dated 22 December 2016).

144. Reference is made to documentation in the information system 'Paragraph', which, in turn, refers to www.zakon.kz.

145. Reference is made to an interview with the Minister of Foreign Affairs of the Republic of Kazakhstan, published in the information system 'Paragraph'.

146. Exploration contracts executed prior to the effective date of the Code remain in force.

147. The wind power plant Astana EXPO-2017 of 100MW capacity is exempted from this tariff; it is set as KZT59.7.

148. Order of the Minister of Energy no.33 dated 30 January 2018 on Approval of the Maximum Auction Prices.

149. International Renewable Energy Agency Charter, ie IRENA, which was ratified by Kazakhstan in 2013.

150. See www.gov.kz/memleket/entities/energo/activities/4910?lang=ru.

151. Conditional target is subject to additional international investments, access to green climate funds and some other conditions.

152. The EC defines target as follows – by 31 December 2030 Kazakhstan's carbon balance (which is delta between actual GHG emissions and actual GHG absorption for a specified period) has to be reduced not less than 15% as compared to the level in 1990.

153. Art.1, Law No. 242-VI ZRK on Special Economic and Industrial Zones dated 3 April 2019, as amended.

154. Chapter 79, Tax Code adopted by Law No. 2120-VI ZRK dated 25 December 2017, as amended.

Energy law in Latvia

Recent developments in the Latvian energy market

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Natural gas sector – strategic gas reserves, Russian gas import ban, new LNG terminal in Latvia

The Russian invasion of Ukraine has clearly affected the global natural gas market. Latvia, which has relied on Russian gas supplies for decades, had to reconsider its approach to natural gas sources. The Latvian Government ("Government") took several steps in that respect.

Firstly, the Government tasked the State-owned energy company, AS Latvernergo, with securing two types of natural gas reserve: strategic reserve and energy supply safety reserve. Both types of reserve are aimed at securing a sufficient and uninterrupted supply of natural gas for users in Latvia. Natural gas reserves will be kept at Inčukalns Underground Natural Gas Storage Facility ("IUGSF") in Latvia, the only gas storage of the kind in the Baltic States.

Secondly, as of 1 January 2023, importing natural gas from Russia will be prohibited. The Government considers natural gas reserves at IUGSF to be sufficient for a short-term gas supply. In addition, Klaipeda liquified natural gas ("LNG") facility in Lithuania and Paldiski LNG facility in Estonia will provide alternative gas supply routes in short and mid-term (Paldiski LNG facility to be commissioned towards the end of 2022 or early in 2023). In the long term, the Skulte LNG terminal will be erected in Latvia (expected to become operational in 2024) and will become an important natural gas entry point for Latvia.

Thirdly, as aforementioned, it is expected that in 2024 a new LNG facility in Skulte, Latvia, will become operational. The Government has approved the construction of the facility and is willing to facilitate the process by reducing bureaucratic hurdles for implementation of the project. A potential upside for the Skulte LNG terminal is its relative proximity to the IUGSF, if compared to Klaipeda and Paldiski facilities.

Development of offshore and onshore wind parks

It is estimated that Latvia with its long coastline has about 15GW of available, but untapped offshore wind capacity. With recent spikes in electricity and natural gas prices, offshore wind could potentially have a significant positive impact on the local and regional electricity market.

According to information published by the Government, several applications from internationally renowned developers have been received regarding choosing areas in the sea for the construction of offshore windfarms. ELWIND, a joint Latvian-Estonian offshore windfarm project, is moving forward with the electricity transmission system operators ("TSOs") of Latvia and Estonia (ie AS Augstsprieguma tīkls and AS Elering, respectively) and conducting joint studies regarding possible onshore connection sites for the project. It is intended that the ELWIND project will be completed by 2030 at the latest.

The Government is also considering various ways of increasing the speed in the development of onshore windfarms. In comparison to other Baltic States, Latvia significantly lags behind in terms of installed onshore wind capacity. In 2022, the Government proposed certain measures to reduce the administrative burden on onshore windfarm projects. Additionally, the Government has tasked AS Latvenergo and AS Latvijas Valsts Meži, both state-owned companies owning and managing Latvia's woodland, to create a joint venture to develop onshore windfarms.

An additional development with the potential to facilitate onshore windfarm development is the recent amendment to the Electricity Market Law, providing for a 'inconvenience payment' to local municipalities for windfarms built within the administrative territory of respective municipalities. One of the barriers for onshore windfarm development in Latvia has been the negative perception of these projects in rural areas, with local municipalities usually rejecting such projects. Now, it is expected that the prospect of financial advantage could change attitudes towards windfarms, further facilitating such projects in the coming years.

Changes in grid connection procedures

Over the last two years, there has been a constant increase in demand for transmission system capacities, ie grid connection requests from onshore windfarm and solar farm developers have been steadily increasing. AS Augstsprieguma tīkls, a Latvian electricity TSO, recently announced that the free grid capacity is in a deficit.

In 2022, the Public Utilities Commission ("PUC") approved new transmission system connection rules for electricity producers. The new rules sought to simplify and speed up the grid connection procedure.

At the same time, many of the vacant grid capacity has been reserved for projects with unclear prospects of implementation (ie respective developers might lack the resources for the implementation of their applied projects). To deal with this issue, the Government has introduced, via recent amendments to the Electricity Market Law, a capacity deposit payment mechanism. Using this mechanism, electricity TSOs will be entitled to ask for deposit payments for the grid capacity reservations. The aim of this regulation is to ensure that the

Latvian grid capacity is not blocked by applicants who do not possess the necessary resources to implement a new wind or solar farm project. Such applicants currently obtain the necessary permits and then try to sell their respective projects to developers with the appropriate financial capacity and experience).

The new provision stipulates that the PUC will issue special regulations on the determination and payment mechanism of the capacity deposit payment, including provisions regarding how this payment should be included in the grid connection payment. To date, the PUC has not published a draft of these regulations. Therefore, it is impossible to indicate the specific amount of this payment. However, the industry expects that the capacity deposit payment will be about €50,000/MW.

The relevant provision in the Electricity Market Law provides that an applicant will lose their deposit if they fail to connect their generating unit to the grid due to reasons unrelated to the TSO.

Overview of the legal and regulatory framework in Latvia

A. Electricity

A.1 Industry structure

Nature of the market

The Latvian electricity market has been fully liberalised following implementation of the Third Energy Package, and consumers are free to choose their suppliers. Electricity is traded in the Nord Pool Spot, the leading power market in Europe.

Key market players

On the production side, the key market player is AS Latvenergo, a fully state-owned joint stock company. Most of the electricity produced by AS Latvenergo comes from large hydropower plants. In addition, AS Latvenergo operates two large natural gas fuelled combined heat and power ("CHP") plants in Riga, Latvia's capital.

AS Augstsprieguma tīkls is the sole transmission system operator ("TSO") in Latvia. The distribution system operator ("DSO") is AS Sadales tīkls, a fully owned subsidiary of AS Latvenergo. There are nine other DSOs in Latvia, but their operation is restricted to limited geographic areas.

There are 70 electricity producers and 43 electricity traders in Latvia. A subsidiary of AS Latvenergo, AS Enerģijas publiskais tirgotājs, administers an electricity compulsory procurement scheme related to Latvia's feed-in tariff system.

Regulatory authorities

The electricity market is shaped primarily by the Ministry of Economics as the main policymaker, and the Regulator, the Public Utilities Commission ("PUC"), is responsible for licensing and tariffs.

Legal framework

The basic legislative framework in the electricity industry consists of the Energy Law, the Electricity Market Law, the Law on Regulators of Public Services, and several subordinated regulations issued by the Cabinet of Ministers and Regulator.

In 2021 and 2022, offshore wind generation became topical in Latvia. It is expected that numerous large-scale wind farm projects will be implemented in the future, starting with the joint Latvian-Estonian ELWIND project. The ELWIND project is planned to have an electricity output of over 3TWh per year and be commissioned by 2030. However, the development of offshore wind farm projects is currently delayed by the lack of up-to-date regulatory framework based on the accepted best practices within the industry.

Implementation of EU electricity directives

The Third Energy Package has been implemented in Latvia and as of 1 January 2015, the Latvian electricity market has been fully liberalised, with households joining the market.

A.2 Third party access regime

The Electricity Market Law gives market participants the right to use the transmission and distribution systems at the tariffs approved by the Regulator. Access to the transmission and distribution systems is subject to the market participants complying with the technical requirements of the system operator.

In recent years, the regulatory environment regarding new grid connections has significantly improved through the simplification of the administrative process for acquiring access to the grid. The timescale for several procedures has been reduced and the process for obtaining a full connection is now shorter. Despite this, the costs related to new grid connections remain relatively high.

In the first half of 2022, the Latvian Government ("Government") announced several political initiatives to facilitate expansion of onshore wind energy production. These include standardised and simplified requirements in relation to environmental impact assessment procedures and grid connections.

A.3 Market design

The transmission and distribution of electricity requires a licence, issued by the Regulator, unless the applicable thresholds are not exceeded (ie if respective network voltage is up to 110kV). It usually takes one month to decide whether this licence will be issued. However, in exceptional cases, that period may extend to four months.

The generation and supply of electricity can be carried out by entities on their registration with the Regulator. The procedure is formal and in usual circumstances would not require more than one month to be registered.

Where the market entrant intends to use the existing transmission and/or distribution system, they must enter into an agreement with the operator of the relevant system(s). Additionally, entities intending to engage in electricity supply are subject to requirements relating to the relationship with the electricity end users, as stipulated by the Electricity Trade and Usage Regulations issued by the Cabinet of Ministers.

A.4 Tariff regulation

In Latvia, distribution and transmission tariffs are regulated under tariff methodologies approved by the Regulator. Both distribution and transmission tariffs are differentiated depending on various technical parameters. Both tariffs include a payment for the respective service (ie actually transmitted or distributed electricity), as well as payment for maintenance and development of the transmission or distribution system.

Tariffs are reviewed by the Regulator on submission of a new tariff application by the service provider. However, the Regulator can review tariffs on its own initiative if factors influencing tariffs have changed. In addition to the distribution and transmission tariffs, the Regulator approves the electricity compulsory procurement component payable by all end consumers in proportion to their respective electricity consumption. The component is approved by the Regulator for each consecutive year as per a calculation submitted by the public electricity trader, AS Enerģijas publiskais tirgotājs.

A number of significant measures have been implemented since 2018 to reduce the amount of the electricity compulsory procurement component. This was done due to the fact that the component has adverse effect on electricity bills and, as a consequence, on competitiveness of industrial consumers operating on international markets. A support scheme for energy-intensive producing entities was therefore introduced, compensating certain parts of their expenses related to the said component. An internal revenue rate ("IRR") of 9% was also set for all beneficiaries of the feed-in tariff scheme.

A.5 Market entry

Market entry for entities engaged in the generation and supply of electricity is relatively simple, and both of these activities can be carried out on registration with the Regulator. The registration process requires only the submission of certain documents; the Regulator will usually register the applicant within one month of the application being submitted.

The installation of new generating capacity (or the expansion of existing capacity) is subject to approval by the Ministry of Economics ("Ministry"). The relevant permit can be obtained within 30 days provided that the applicant has submitted full and correct information to the Ministry.

In practical terms, introduction of new generating capacities may be more complicated due to the process of connecting installed capacity to the grid, which is still relatively burdensome in terms of the necessary investment and procedure required. However, in recent years the procedures have been significantly improved, although the financial aspect may still be considered relatively unattractive for potential investors. Furthermore, it is expected that with respect to onshore wind farms, the procedure could be further simplified in the near future to facilitate the development of such projects in Latvia.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The Electricity Market Law contains certain public service obligations that have to be ensured by a public trader or DSO. For example, a public trader must purchase electricity from producers participating in the compulsory procurement scheme and receiving a feed-in tariff for electricity generated from renewable energy sources ("RES") or at CHP plants. A public trader must also administer state aid to energy-intensive manufacturing undertakings if and when an aid scheme is approved by the European Commission ("Commission"). A DSO must ensure the supply of last resort for consumers without effective supply and balancing agreements (captive customers). In practice, the supply of last resort is ensured by an electricity trader selected by the DSO in an open and non-discriminatory procedure

Smart metering

There is no legally binding requirement to implement smart metering in Latvia within a certain time frame. However, smart metering is gradually being introduced by the DSO. Under the planned introduction, the replacement of old metering devices with devices ensuring smart metering will be completed by 2023.

At the same time, households that are generating electricity from RES for their own consumption are entitled to transfer excess generated energy to the grid. This has been possible since 1 January 2014, provided that the household has obtained a permit for microgeneration capacity installation and a smart electricity meter is installed. Since 2021, microgeneration on a separate household level has expanded, and it is expected that the introduction of regulation regarding energy communities will facilitate this trend further.

Electric vehicles

Electric vehicles ("EVs") have not gained popularity in Latvia due to several reasons, for example, the lack of appropriate infrastructure and relatively high purchase price, if compared to vehicles with internal combustion engines. However, it is expected that over the next two years, the number of EVs will increase by over three-fold, and within the next seven years by ten-fold (by 2030).

This growth will be facilitated by continuously expanding public infrastructure (charging stations) all over Latvia. Additionally, new support mechanisms are being implemented to persons willing to acquire an EV.

A.7 Cross-border interconnectors

Latvia is well connected with the Baltic and North European regions grid through fully functioning interconnectors with Lithuania and Estonia, which are sought to be extended to increase cross-border capacities. In addition, indirect interconnections (through Estonia and Lithuania) with Finland, Sweden and Poland are in place, ie two Estlink undersea cables between Finland and Estonia, the Nordbalt undersea cable between Sweden and Lithuania and the LitPol interconnector between Poland and Lithuania. Another interconnector between Latvia and Estonia is contemplated in the context of the ELWIND project, which will see a joint offshore wind farm developed by both countries in the next few years.

Latvia has also historically been connected with the Russian/Commonwealth of independent States ("CIS") electricity network, through interconnectors constructed before 1990. However, a synchronisation project has been commenced with a view to terminate this historically developed situation and synchronise Latvia's electricity network with the European network. The first tests of synchronisation were carried out in

2019 by temporarily switching off grid connections with Russia and Belarus and ensuring its operation on local generation capacities and existing electricity interconnections with Scandinavia and Poland (through Lithuania). Completion of the synchronisation project has been scheduled for 2025 and would require adjustment of internal electricity grid, as well as building new, or enhancing existing interconnectors with Lithuania, Poland and Estonia.

Interconnectors are operated by TSOs of the respective states, and interconnection capacities among the Baltic States, as well as between the Baltic States and the Russian Federation and Belarus, are regulated by special agreement among those TSOs.

B. Oil and gas

B.1 Industry structure

Nature of the market

The natural gas market in Latvia was liberalised in 2017, ending a 20-year monopoly by AS Latvijas Gāze, the vertically integrated market incumbent, which was maintained in accordance with the outcome of its privatisation process.

Since 2020, Latvia, Estonia and Finland have created a single entry/exit area, and the gas market has been widened accordingly. However, most of the gas supplies still came from Russia, with Klaipeda LNG in Lithuania providing for a small share of the gas supplies to the joint Latvian, Estonian and Finnish market. A gas interconnector between Poland and Lithuania ("GIPL") beginning operations as of May 2022, is the most recent development with a potentially positive impact on the regional gas market.

It is expected that Latvia's natural gas market will change significantly in the near future. Russia's invasion of Ukraine has underlined security of supply issues. In addition to Klaipeda LNG, another two LNG projects are upcoming: Paldiski LNG in Estonia (to become operational in 2022) and an LNG terminal in Latvia (which is still undergoing a feasibility study, however, could be commissioned in 2023).

Key market players

AS Latvia's Gāze remains the most notable gas trader in Latvia, expanding its operations to Estonia and Finland after creating a joint market among these countries. However, in the wake of security of supply issues posed by Russia's invasion of Ukraine, AS Latvenergo has been designated by the Government as the entity to ensure Latvia's natural gas reserve.

AS Conexus Baltic Grid is the unified TSO and storage system operator in Latvia. Considering the importance of the Inčukalns Underground Gas Storage Facility, the State of Latvia has secured its control over AS Conexus Baltic Grid via the electricity TSO, AS Augstsprieguma tīkls, the minority shareholder being MM Infrastructure Investments Europe Limited (subsidiary of the Japanese Marubeni Fund).

The sole DSO in Latvia is AS Gaso, a fully owned subsidiary of AS Latvijas Gāze.

In absence of oil production, Latvia does not have a meaningful oil industry.

Regulatory authorities

The gas market is shaped primarily by the Ministry of Economics as the main policymaker, and the Regulator is responsible for licensing and tariffs.

Legal framework

The basic legislative framework of the gas industry consists of the Energy Law, the Law on Regulators of Public Services, and a series of subordinated regulations of the Cabinet of Ministers and Regulator.

Implementation of EU gas directives

As a result of full implementation of the Third Gas Directive, AS Latvijas Gāze was gradually reorganised and two new companies were founded along with the remaining natural gas trading company, AS Latvijas Gāze. The two new companies are AS Conexus Baltic Grid, a unified natural gas TSO and storage system operator, and AS Gaso, a DSO.

Overall, the Third Gas Directive has been implemented in Latvia, and the gas market operates under the legal framework set by the Third Gas Directive.

B.2 Third party access regime to gas transportation networks

Third party access to gas transportation networks is regulated, with access rules being approved by the Regulator. As of 2020, Latvia, Estonia and Finland form a single entry/exit area. Accordingly, within this area all internal cross-border fees have been abolished, and joint transmission system tariff applies.

Access to the transmission system is gained through a conclusion of transmission service agreement. Capacity allocation is set by the Common Regulations for the Use of Natural Gas Transmission System, applicable to the whole entry/exit area, with certain exceptions (eg with respect to Inčukalns Underground Gas Storage Facility, Balticconnector, which are regulated separately).

B.3 LNG terminals and storage facilities

There are no LNG terminals in Latvia. The nearest operating LNG terminal is in Klaipeda, Lithuania. Aanother terminal will be built and begin operating in the second half of 2022 in Paldiski, Estonia.

However, considering the security of supply issues raised by Russia's invasion of Ukraine, Latvia is considering building an LNG terminal. A positive factor which facilitates the development of an LNG terminal in Latvia is the Inčukalns Undergraund Gas Storage Facility ("IUGSF"), operated by the unified TSO and storage system operator, AS Conexus Baltic Grid. Proximity of a large-scale storage facility (IUGSF's capacity is about 2.3 billion m3) could facilitate the use of the contemplated LNG terminal not only by gas suppliers in Latvia, but also from Finland, Estonia and Lithuania, as these three countries lack significant local storage capacities.

Regarding the IUGSF, the storage access regime (regulated or negotiated) depends on the actual use of storage capacity over the previous calendar year. A regulated regime applies in case of the adequate use of storge capacity, and a negotiated regime is being used in case of a reduction in the use of storage capacity.

As for the regulated regime, the system operator provides storage capacity on the basis of IUGSF capacity product auctions which are organised by the system operator.

B.4 Tariff regulation

Tariffs are being set by the Regulator, based on the tariff calculation methodology and an application from the respective system operator. The main principle applicable to tariffs is that they should cover economically justified costs and ensure rentability of the system service provision.

The regulatory period for transmission tariffs is three years, and current period ends on 30 September 2022. The tariff, an exit point usage fee for supplying Latvia's consumers, depends on the amount of recoverable costs of ensuring gas supply. Additionally, the Regulator also approves tariffs for a standard transmission system capacity product.

Distribution tariffs consist of changing and fixed part, based on the yearly consumption (in kWh) and permitted load (m^3/h), respectively. Current tariffs have been set for the regulatory period from 1 July 2021 to 31 December 2025, with tariff periods corresponding to each respective calendar year. The DSO has the right to set distribution tariffs, based on the methodology, for each tariff period, adjusting them to changes in allowed or planned income.

Regarding both of the transmission and distribution tariffs, the Regulator has the right to initiate revision of existing tariffs if factors affecting tariff calculation have changed.

B.5 Market entry

Market entry for gas traders is relatively simple, as trading is not subject to licensing. Any entity intending to trade in natural gas in Latvia must register with the PUC, which maintains the register of natural gas traders.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

AS Conexus Baltic Grid is tasked with the security of supply obligation, which effectively means that it must ensure certain volume (3,160,000MWh or 300 million m3) of natural gas in the storage throughout the withdrawal season, ie until 1 March of each respective year. To ensure the required volume of gas, AS Conexus Baltic Grid organised auctions in 2017 and 2018, purchasing the respective service (storage of certain volumes of gas in the Inčukalns underground storage facility) from natural gas suppliers.

Additionally, shortly after Russia's invasion of Ukraine, the Government tasked AS Latvenergo with securing 2TWh of natural gas in order to ensure due operation of AS Latvenergo owned natural gas CHPs. The latter ensures heating for Latvia's capital, Riga, as well as ensuring baseload capacity of up to 1,000MW for electricity generation.

Furthermore, the Energy Law has been amended to provide for additional natural gas reserve; AS Latvenergo would have to secure supply of 1.8 to 2.2TWh of natural gas to be stored at the Inčukalns Underground Gas Storage Facility. AS Conexus Baltic Grid would be responsible for storage, including the related costs in the transmission tariff.

Smart metering

Smart metering is not applied in natural gas sector in Latvia.

B.7 Cross-border interconnectors

The natural gas transmission system of Latvia is connected with the transmission systems of Estonia, Lithuania and Russia. Since 2015, when the Klaipeda LNG terminal commenced operation, the transmission systems of the Baltic States have been considered interconnected with the other transmission systems of the European Union.

Isolation of the Baltic gas market has further diminished over the last few years through the construction of GIPL, a gas interconnector between Poland and Lithuania which commenced operation in May 2022, as well as the completion of the Balticconnector pipeline commissioned in 2019, linking Estonian and Finnish gas systems.

Estonia and Finland have agreed to cooperate on the construction of an LNG facility in Paldiski, Estonia. Similarly, Latvia is considering the construction of its own LNG terminal in Skulte and is looking for private investors' interest and investigating the overall feasibility of such a project. The Paldiski LNG terminal is expected to commence operations towards the end of 2022, while the LNG terminal in Latvia might become operational in 2023, at the earliest.

C. Energy trading

C.1 Electricity trading

Electricity trading in Latvia is carried out on two levels, ie wholesale and retail. The wholesale level entails trading in the Nord Pool Spot. As new interconnectors with Finland and, especially, with Sweden have been installed, Latvia has benefited significantly from the spot pricing as electricity has become cheaper. In addition, the public electricity trader, AS Enerģijas publiskais tirgotājs, must purchase electricity generated by entities participating in the compulsory electricity purchase scheme on a wholesale basis.

On the retail level, electricity is traded by entities registered with the traders' register maintained by the PUC. These activities are regulated in Latvia by the Electricity Market Law and the Regulations Regarding the Trade and Use of Electricity, as approved by the Cabinet of Ministers, which provide detailed regulations regarding the relationship between electricity suppliers and customers.

Electricity to household users is traded on the basis of a supply agreement, while non-household users must have a balancing agreement in addition to the electricity purchase agreement. Usually, balancing services are included in the supply agreement, ie the trader takes responsibility for the consumer's balancing obligation. Consumers have the right to choose their supplier freely.

Generally, electricity can be traded in the balancing market. Ensuring the system balance is the responsibility of the TSO. The TSO provides balancing services to the users, electricity generators and DSOs connected directly to the transmission system. The users, electricity generators and other DSOs connected to the distribution system receive the balancing service from the DSO.

C.2 Gas trading

On a wholesale level, it is expected that with development of new LNG capacities and commencement of gas supplies via GIPL (gas interconnector between Poland and Lithuania), and in the light of potential Russian gas import ban, market structure could change significantly, ie AS Latvijas Gāze might lose its dominant position in the market.

On a retail level, gas trading is subject to a detailed regulation of the Cabinet of Ministers to ensure due protection of customers, at the same time safeguarding predictability on the sellers' side.

In the first half of 2022, there were 29 gas traders on the register maintained by the Regulator.

D. Nuclear energy

N/A

E. Upstream

N/A

F. Renewable energy

F.1 Renewable energy

The Energy Law generally defines RES as wind, solar, geothermal, tidal, and hydro energy, waste landfill site and sewage treatment plant gas, biogas and biomass (ie biologically degradable fraction in products, industrial and household waste, agricultural, as well as forestry and similar residual materials). In practice, two of the most exploited RES are wood pulp and water. However, currently topical sources are wind, solar energy and biogas.

In the coming years, Latvia is expected to unlock its huge offshore wind capacity. In addition, the simplification and standardisation of regulation should facilitate more active development of onshore wind farms.

Regarding biogas, the Government is looking at possible options related to its use. Biogas may be primarily used in the transport sector, since many of biogas plants are located close to natural gas transmission networks and adjusting the quality of biogas for its injection into natural gas system might require excessive investments.

F.2 Renewable pre-qualifications

For several years there has been a moratorium on new feed-in tariff permits; no new permits are being issued, and market entrants cannot benefit from the existing feed-in tariff scheme.

F.3 Biofuel

The production and sale of biofuel is regulated by the Biofuel Law, which sets out the responsibilities of the Government in relation to the production and sale of biofuel, as well as the requirements applicable to economic operators engaged in the biofuel industry. Latvia is falling behind significantly from reaching the 2020 target for the use of biofuels in the transport sector. Significant improvements in the regulatory environment and the establishment of a level playing field for all types of biofuels will be necessary to increase the proportion of biofuels used in end consumption.

It was expected that a new Transport Energy Law would address all the shortcomings of existing regulatory framework. However, the first attempt to draft such a law in 2019 was unsuccessful. After some reconsideration and re-drafting, the Ministry of Economics introduced another draft Transport Energy Law. However, this draft is also progressing through the legislative procedure slowly.

Once adopted, the draft law is expected to introduce a mandatory obligation scheme for fuel retailers, ie they would have to ensure that a certain amount of all fuels sold throughout a calendar year is from biofuels.

G. Climate change and sustainability

G.1 Climate change initiatives

For the past few years, climate change initiatives have mainly focussed on energy efficiency projects, both on the household and industrial level. Special grants are available for renovation projects, and the Government is extending the base of eligible recipients of such a support.

G.2 Mmission trading

With the exception of the EU Emissions Trading Scheme ("ETS"), there are no other national ETSs available in Latvia. The Latvian ETS includes operators holding special greenhouse gas ("GHG") emission permits and carrying out certain types of polluting activity that reach the set threshold. Other entities with lower polluting thresholds may join the system voluntarily.

Operators involved in the ETS must monitor emissions, submit a verified emission report on a yearly basis, and transfer the indicated emission volume to the State every year based on information provided in the submitted report. Residual volume of emission quotas can be freely traded by operators or accumulated for consumption in future.

G.3 Carbon pricing

Carbon pricing in Latvia represents a mix of applicable taxes (fuel excise and carbon), and permit prices from the EU ETS.

G.4 Capacity markets

N/A

H. Energy transition

H.1 Overview

Considering its high share of renewable energy (about 40%, with more than 50% of electricity coming from RES), Latvia's main focus in the coming years might be to gradually decrease reliance on natural gas in electricity and heat generation. An obvious replacement could be on- and off-shore wind energy in electricity generation, and woodchip in heating sector.

For many years, the Latvian wind energy sector has been underdeveloped, in spite of Latvian wind conditions being comparable to many of the leading European wind energy forerunners. Presently, the decrease in technology costs and the availability of land have fuelled an inflow of investments in wind energy projects. In recent years, the development of new onshore wind energy projects became even more accessible, due to revised planning requirements. Regulatory enactments were amended by relaxing some of the too-stringent restrictions and requirements for wind farm development projects. Several planning restrictions were substituted with the ability to evaluate and possibly mitigate the effect of such restrictions within environmental impact assessments. Another novelty was the possibility to construct wind farms in forests, which improves the available space for the development of new projects.

Latvia, with its long coastline and beneficial wind resources, provides for a significant, yet unexplored, potential for offshore wind farm development. The country's National Energy and Climate Plan 2030 ("NECP") aims to increase its total offshore wind power capacity to at least 800MW, over the next ten years. A possible catalyst for future offshore projects might be the ELWIND project, a joint effort by the Latvian and Estonian governments to develop a common offshore wind farm. The intention is to set the location, ensure access to the transmission grid, and then auction the respective area to private developers for the construction of a wind farm. Both governments have entered into the respective Memorandum of Understanding, and a designated working group, including TSOs of both countries, is actively working on this project, set to materialise in an operating large-scale offshore wind farm in 2030. This move has been successful in attracting international investor interest for the Baltic offshore wind market.

H.2 Renewable fuels

Hydrogen

Under Latvia's NECP, hydrogen is named as one of the innovative solutions in the field of renewable energy technology. In particular, Latvia is considered one of the countries with the possibility of replacing fossil fuel in transportation. The Plan also provides for the creation and development of respective infrastructure (filling stations).

In addition, the Plan envisages that hydrogen in transport could be facilitated by stimulating local municipalities of the big cities to use public transport which is fuelled by renewable fuels, including hydrogen. However, reportedly negative experience of SIA Rīgas satiksme, municipality-owned public transportation company operating in Riga, Latvia's capital, puts such a prospect in serious doubt.

According to the NECP, the development of hydrogen projects should be viewed on the regional level. Therefore, a special forum, the Baltic Sea Renewable Energy and Hydrogen Experts Roundtable ("BASREHRT"), has been created by relevant stakeholders from Sweden, Latvia and Estonia to discuss possible future projects concerning the production and consumption of hydrogen. Currently, discussions regarding the development of hydrogen production are mostly mentioned in the context of the expected surge in offshore wind energy projects.

Ammonia

There are no specific plans regarding the use of ammonia in Latvia.

H.3 Carbon capture and storage

In Latvia, carbon capture and storage ("CCS") is primarily viewed in the context of land use and forest management (ie efficient land use and management of forest areas would eventually serve for the CCS purposes). Accordingly, there are no specific CCS projects.

H.4 Oil and gas platform electrification

N/A

H.5 Industrial hubs

N/A

H.6 Smart cities

There is no specific regulatory framework in Latvia concerning smart cities. As a private initiative, several research institutions and private companies have created the Smart City Cluster (*Viedās pilsētas klasteris*), whose objective is to facilitate the development of products and services related to the smart cities concept.

I. Environmental, social and governance (ESG)

Generally, investing in RES energy facilitates the achievement of ESG targets, in particular regarding the environmental targets. Accordingly, the number of greenfield RES energy projects, especially in wind and solar sectors, is constantly increasing in Latvia. This applies not only to the grid energy production, but also to the production for self-consumption.

Energy law in Lithuania

Recent developments in the Lithuanian energy market

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2021 was a year marked by unprecedented changes and uncertainties in the energy commodity markets as well as in the regional geopolitical situation. Unfortunately, the Russian invasion of Ukraine in February 2022 has contributed to challenges in the near future.

According to preliminary estimates published by the Lithuanian Government, gas and electricity prices for the population are likely to increase twofold to 40% in 2023. The energy price hike remains a pressing issue for businesses and households. Although Lithuania is part of the Nordic region, which is accustomed to winter and cold weather, the upcoming cold season of 2022 may present new challenges and difficulties.

Renewable energy

On the positive side, the context of these challenges has fundamentally changed the attitude of all consumers and market players in favour of the development of renewable energy. Investors' and market players' interest in the development of renewable energy is at an all-time high. This interest is also being matched by a corresponding response from public authorities. The package of laws adopted in 2022 ("Breakthrough Package") has already introduced some regulatory relief, but additional reductions in administrative tax and other legal burdens on energy development are expected in the near future.

The Lithuanian Government has approved ambitious plans to make Lithuania an energy exporting country by 2030, with its electricity needs met by local and renewable generation. The total installed capacity of renewable energy in Lithuania would reach 7GW, of which 1.4GW would be generated by offshore wind, 3.6GW by onshore wind and 2GW by solar power plants.

The changes underway will undoubtedly make a significant contribution to increasing energy security and implementing the European Union (EU) Green Deal in Lithuania. If the renewable energy developments continue to be targeted and successful, 2030 will be a significant year for Lithuania.

Other energy developments

In addition to the regulatory changes and the development of renewable energy, the energy crisis in Lithuania is forcing the search for new ways to manage risks through financial-insurance instruments. Therefore, in the future, Lithuania may see new and innovative risk management tools offered by financial and insurance institutions; these will help market participants to avoid similar electricity market fluctuations in the future.

The current energy crisis has opened up wider opportunities for the use of electricity demand-side response services, ie Lithuanian businesses are moderately discovering a model where consumers' electricity demand and supply (generation) are directly matched to sell, buy or auction the amount of unused or generated electricity and the amount of unused or delivered power. In this model, short-term reductions in consumption result in significant revenues for consumers. This is beneficial because electricity consumption, adjusted or corrected accordingly to market needs, helps to maintain a stable frequency of electricity on the grids.

With energy prices rising to unprecedented heights, it is important to note that adjusting consumption patterns to market conditions can lead to significant reductions in the cost of energy resources. The Lithuanian regulator estimates that Lithuania can save around €40-50 million per year by using these services and changing consumption patterns.

Overall, it is clear that Lithuanian households and businesses are facing significant challenges in terms of energy prices, but at the same time, there is a clear opportunity for businesses looking to invest in renewable energy, as well as other alternative energy mechanisms.

Overview of the legal and regulatory framework in Lithuania

A. Electricity

A.1 Industry structure

Nature of the market

2021 was a year marked by unprecedented changes and uncertainties in the energy commodity markets as well as in the regional geopolitical situation. Unfortunately, the Russian invasion of Ukraine has contributed to the challenges of the near future. The significant increase in electricity prices forced governments across Europe, including the Government of Lithuania ("Government"), to find ways to adjust their energy market designs and regulations to reduce the burden of increased prices on customers.

In the second half of 2021, a balanced solution was reached between the Government and the Lithuanian market players to amortise the increase in electricity prices. The scheme involves market players amortising the increase in prices (eg the difference between the tariff set by the National Energy Regulatory Council ("NERC") and the wholesale commodity prices) while the Government commits to return the difference to the market players through regulated tariffs throughout 2023-2027.

Due to the same reasons, another market design adjustment was introduced because the second stage of electricity market deregulation (business-to-consumer related) was postponed by six months (from January to July 2022). However, it is not expected to affect the overall target of having a fully deregulated electricity household consumer market by the end of 2022.

Key market players

Litgrid AB is the Lithuanian electricity Transmission System Operator ("TSO") engaged in managing electricity flows and ensuring the stable operation of the national electricity system. EPSO-G UAB, a state-owned company, owns 97.5% of Litgrid AB shares and is listed on the Nasdaq Baltic Secondary List. The TSO has implemented the full ownership unbundling ("FOU") model.

Energijos Skirstymo Operatorius AB ("ESO") is the main Distribution System Operator ("DSO") and controls the low and medium voltage electricity distribution network in Lithuania. Ignitis Grupė AB, a state-owned company, is the sole shareholder of ESO. The DSO is fully independent from other activities unrelated to distribution in terms of legal form, organisational structure and decision-making procedures.

Baltpool UAB is the operator of the Lithuanian Energy Exchange entitled to organise the trade of solid biofuel products and to act as the administrator of public service obligations ("PSOs") funds. EPSO-G UAB, a state-owned company, owns 67% of Baltpool UAB. The remaining 33% of the company's share capital belongs to Klaipėdos Nafta AB, a state-owned company.

Ignitis Gamyba AB is the largest generator of electricity in Lithuania; the company owns the Lietuvos Elektrinė Power Plant, the Kruonis Hydro Pumped Storage Power Plant, Vilnius Combined Heat and Power (CHP) Plant, and the Kaunas Hydro Power Plant. Ignitis Grupė AB is the sole shareholder of Ignitis Gamyba AB.

Regulatory authorities

The regulatory policy for the electricity sector is determined by the Lithuanian Parliament ("Parliament"), the Government and the Ministry of Energy, and is monitored by the NERC.

The NERC is responsible for ensuring effective competition in the electricity market, non-discrimination between customers and suppliers, and the provision of services of a certain quality to all customers. The NERC also ensures that the TSO and DSOs provide information to interested parties on interconnectors, grid usage and capacity allocation, as well as controlling the effective unbundling of accounts, etc.

The NERC applies the incentive regulation, ie sets the price caps of the regulated prices of the services provided by the energy undertakings, which after reaching the set efficiency of their operations, enables the electricity undertakings to reduce costs, thereby benefitting customers.

Legal framework

The basic regulatory framework for the energy sector consists of the National Energy Independence Strategy, the Law on Energy, the Law on Electricity and the Law on Energy from Renewable Sources.

The Law on Energy sets out the main aims of energy activities in Lithuania as well as the legal basis for state management, regulation, supervision and control of the energy sector, the general criteria, conditions of and requirements for public relations, and the main areas of state energy policy.

The Law on Electricity establishes the legislative framework for the organisation of the Lithuanian electricity sector governance, regulation, supervision, control and operations. The Law on Electricity also regulates the relationship between the institutions that regulate and oversee the electricity sector, electricity generators, service providers, consumers and the national electricity sector in the areas of electricity generation, transmission, distribution, supply, ensuring consumers' rights and legitimate interests.

Implementation of EU electricity directives

The Lithuanian national regulation has been amended to implement European Union ("EU") requirements. As such, the Third Energy Package has been fully transposed into Lithuanian law.

In November 2021, Parliament approved a package of legislative amendments implementing the Clean Energy Package. The transposition of the provisions of the EU package has established the modern electricity market model envisaged across the EU, which is better adapted to market innovation and more market-based, and has enabled the integration of a greater share of renewable energy sources ("RES"). A key objective of this package is to enable consumers to act as market participants.

A.2 Third party access regime

The Law on Electricity provides that all market participants have a right of access to electricity transmission facilities as a regulated third party. This right is exercised in accordance with the Grid Code, which imposes an obligation on the TSO to grant network access on a non-discriminatory basis. The TSO must ensure that those applying for connections who meet the established technical requirements are granted use of the system. Access can be denied only on the basis of non-discriminatory technical criteria.

A.3 Market design

The electricity market consists of wholesale and retail trade in electricity. Power generating companies selling electricity to suppliers take part in wholesale trade. This market also includes TSOs and DSOs that purchase electricity to compensate for generation losses in the transmission and distribution grids. Participants of the wholesale trade may enter into bilateral agreements directly or conclude purchase and sale transactions on an electricity exchange.

Power suppliers and customers that have concluded bilateral electricity sale-purchase agreements with suppliers take part in retail trading.

The TSO (ie Litgrid AB) is responsible for securing national power generation and consumption balance, and for the administration of the regulation and balancing of power in the market.

A.4 Tariff regulation

The prices of electricity and reserve power sold by generators and independent suppliers are not regulated. NERC regulates prices for transmission, distribution and public supply services as well as public electricity prices by setting price caps. The specific prices and tariffs for transmission, distribution, public supply services and public electricity are set and changed by the service supplier.

A.5 Market entry

Licences must be obtained from the NERC for the following activities:

- Electricity TSO;
- Electricity DSO; and
- Public supply of electricity.

Licences shall be granted to persons having sufficient technological, financial and managerial capacity to enable them to carry out the licensed activities properly. The technological, financial and managerial capacity of persons and the procedure for assessing it shall be determined by the Council. Licences for these activities are granted for an indefinite period to one entity for each defined territory. A licence for electricity transmission is issued to an entity that owns or manages on other legal grounds, transmission systems in Lithuania. A licence for electricity distribution is issued to an entity that owns or manages on other legal grounds, distribution systems directly connected to transmission systems.

Authorisation by the NERC must be obtained for the following activities:

- Generation of electricity;
- Development of generation capacity;
- Construction of a direct line;
- Export of electricity from a non-EU country;
- Import of electricity to a non-EU country;
- Independent supply of electricity; and
- Independent supply of demand response service.

Authorisation for the export of electricity may be granted to electricity generators and suppliers; however, authorisation for the import of electricity can only be granted to electricity suppliers. All electricity generators have a right to supply electricity through a direct line to their branches, subsidiaries and eligible customers. Authorisations for the generation and import or export of electricity are granted for an indefinite period; one-off authorisations for the development of electricity generation capacity or construction of a direct line are granted for a limited period of up to three years.

In order to develop an offshore wind farm, the developer must obtain specific authorisation for the use of a part or parts of the territorial sea of Lithuania and of the exclusive economic zone of Lithuania in the Baltic Sea for the development and operation of power plants using RES. This permit is issued as the result of a tender (the auction for the developer of the first offshore wind farm is planned to be launched in the second half of 2023).

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

In Lithuania, the PSOs in the field of electricity include the optimisation, development and/or reconstruction of power networks implemented by the power network operators in order to ensure the development of generation using renewable energy. This service is provided by TSOs and DSOs. The list of conditions applying to this PSO is set by the Government.

PSOs can be mandated and are regulated by the Government, including the purchase of reserve power and the cost of safely exploiting a nuclear power plant and the utilisation of nuclear waste. The TSO must provide PSOs concerned with dispatching and balancing, reserves, security of supply, regularity, quality and environmental protection.

The performance of strategic projects related to the increase in security of supply (construction of electricity lines for connection with the energy systems of other countries) is also deemed a PSO.

Smart metering

Lithuanian regulation stipulates that smart metering is a long-term and comprehensive process that will be carried out without the consent or request of the individual consumer. Smart metering in Lithuania is expected to be implemented in two phases:

Phase I started in the first half of 2022 and will continue until the end of 2025. In this phase, smart metering will be installed for consumers with the highest electricity consumption (1,000kWh/year) or where the metrological verification of existing metering devices has expired.

In order to meet the state social policy objectives, smart metering will be additionally available in this phase for consumers with disabilities.

Phase II will start in 2026. In this phase, smart metering will be installed for all remaining consumers once the metrological verification of existing meters has been completed.

This phase will provide the possibility for consumers to request the network operator to install a smart metering device before the metrological verification of the consumer's existing metering device expires. In order to make use of this option, consumers must bear a part of the costs related to the installation of the smart metering system, which may not be less than 50%. The exact share of these costs will be determined by NERC. Where a request for smart metering is submitted by a socially vulnerable consumer or a disabled person (the latter can also apply in the first phase), the smart metering will be installed free of charge.

Electric vehicles

It is expected that the wave of renewable transformations will be seen in Lithuania in the coming years. By 2030, Lithuania should have experienced significant changes in its transport sector, both in the areas of electromobility and the use of alternative fuels and sustainable mobility. Based on the strategic decisions of public authorities, Lithuanian authorities are planning to increase the number of public and semi-public charging points for electric cars by 11 times by the end of 2024, and 15 times by 2027. The expansion of the electric car charging points network is to be funded from the EU investment funds, EU Recovery and Resilience Facility (RRF) funds, as well as funds from Sustainable Mobility Fund and other resources. Municipalities and natural and legal persons will be encouraged to exploit these investment opportunities.

Currently, there are only 10,797 electric vehicles ("EVs") registered in Lithuania. 6,523 of those vehicles are purely electric and 4,274 are plug-in hybrid cars. A total of 1,657 M1 pure EVs were registered between January and July 2022 (2,502 in 2021), of which 45% are pure EVs.

A.7 Cross-border interconnectors

The Lithuanian power system has the following cross-border interconnectors:

- four 330kV and three 110kV lines connecting to the Latvian system;
- five 330kV and seven 110kV lines connecting to the Belarusian system;
- three 330kV and three 110kV lines connecting to the Kaliningrad (Russian) system;
- one 300kV constant stream cable with the Swedish system (NordBalt); and
- two 400kV lines connecting to the Polish system (LitPol Link).

B. Oil and gas

B.1 Industry structure

Nature of the market

Although Lithuania does not have substantial oil resources lying beneath its territory, a number of large oil industry facilities, such as the only oil refinery in the Baltic region (with an annual capacity of 10-11 million tonnes), a high-capacity terminal for the import and export of oil across the Baltic Sea, as well as one of the region's most modern reverse export and import terminals for petroleum products, are successfully operating in Lithuania. This suggests that Lithuania has sufficient technical capacity to import oil and petroleum products from various countries, as well as diverse and technically ensured possibilities of supplying petroleum products. Moreover, the country has secured the required amount of state reserves for petroleum products, which protects against disruptions in the supply of petroleum products.

Based on the applicable legal framework in Lithuania, the oil sector in Lithuania operates under specific market conditions:

- there are no legal restrictions on the transport of fuel from the EU Member States or import of fuel from third countries;
- the prices of petroleum products are not state regulated (except for liquefied petroleum gas (LPG) supplied to group facilities and except the fact that the state sets excise tariffs and charges value added tax on petroleum products);
- mandatory quality indicators are set for relevant petroleum products; and
- no transport or import quota have been fixed.

Despite these oil supply and refinery facilities, and also the business-friendly regulation of trade in petroleum products experiencing the trends and new developments in the transport system and global changes, Lithuania is gradually switching to consuming less polluting fuels and electricity. Lithuania is flexibly and efficiently combining the existing infrastructure of the oil and petroleum products sector with the local potential offered by RES.

On 1 July 2007, the Lithuanian gas market became fully liberalised and all customers are now considered eligible to choose their own gas supplier.

Key market players

The main companies in the oil sector are Orlen Lietuva AB and Klaipėdos Nafta AB. The main companies operating in the wholesale and retail sectors are Circle K Lietuva UAB, Viada LT UAB, Neste Lietuva UAB and Baltic Petroleum UAB.

Klaipėdos Nafta has the technical capability to both tranship oil products delivered by rail to tankers and also to tranship oil products delivered by tankers to rail or road tankers.

The terminal has a capacity of 7.1 million tonnes of crude oil and petroleum products per year. The terminal has 30 tanks with a total capacity of 404,500m^3. The majority of the transhipped oil products are oil products produced by Orlen Lietuva AB.

The public Lithuanian Energy Agency ("Agency") is a central organisation within Lithuania that collects and manages stocks of petroleum products. One of the Agency's main objectives is to build up and maintain the Lithuania's oil reserves. The Agency uses public funding to build up and constantly maintain the special stocks of the petroleum products that are to be collected by the Agency to the extent it is sufficient for at least 30 days calculated on the average daily internal consumption of the previous calendar year. The remainder of the stocks will be collected by the obligated companies.

The main gas distribution operator is ESO. The dominant players in the gas market are AB Achema, the main importer of natural gas for own-use, and state-owned company Ignitis UAB, the main importer of natural gas for the supply of customers in Lithuania.

Regulatory authorities

The regulatory policy for the oil sector is determined by the Parliament, the Government and the Ministry of Energy. The trade of oil products is subject to licensing procedures that are set and controlled by the Government.

The regulatory policy for the gas sector is determined by the Parliament, the Government and the Ministry of Energy, and is monitored by the NERC.

The NERC:

- supervises the activity performed by the undertakings;
- approves the methodologies for setting state-regulated prices;
- sets the prices and the prices caps;
- exercises control over the application of the state-regulated prices and tariffs;
- exercises control over the procedures of unbundling the vertically integrated undertakings; and
- performs other functions prescribed by the laws and other legal acts.

Legal framework

The key piece of legislation on natural gas supply is the Law on Natural Gas, under which, among other things:

- the relationship in respect of natural gas transmission, distribution, storage, liquefaction and supply is established;
- rules relating to the organisation and functioning of the natural gas sector, access to the market are set out; and
- the criteria and procedures applicable to the issue of licences for transmission, distribution, storage, liquefaction and supply of natural gas and licences to undertake market operator activities are set out.

A number of acts adopted by the Government and the Ministry of Energy further implement the Law on Natural Gas. These contain regulations for transportation, distribution, storage and supply of natural gas, as well as the licensing regime for these activities.

Activities in the gas sector are subject to licences issued by the NERC, of which there are five categories:

- transportation licences;
- distribution licences;
- storage licences;
- liquefaction licences; and
- exchange operation licences.

Implementation of EU gas directives

Under the Law on Natural Gas, a TSO must be unbundled from supply activities in terms of ownership, unless the gas supplier serves less than 100,000 customers. A DSO must be legally unbundled; however, ownership unbundling is not required.

B.2 Third party access regime to gas transportation networks

New system users are connected to the network if there is sufficient capacity and they meet the relevant connection conditions. Natural gas undertakings may, subject to giving duly substantiated reasons, refuse access to the system where there is a lack of capacity or where the access to the system would prevent them from carrying out the PSOs. Otherwise, such undertakings encounter serious economic and financial difficulties with take-or-pay contracts. A refusal based on take-or-pay commitments may be recognised as valid solely subject to the NERC's approval.

Access to the network system is granted under the terms and conditions of a connection agreement. Gas is supplied when the user's system has been connected to the operator's system and following the conclusion of a gas sale-purchase agreement and, if necessary, a transportation or distribution agreement.

An eligible customer may be issued a permit to build a direct pipeline to its system if the operating gas system is unable to provide the required gas volume; however, the customer must bear all connection expenses and compensate for the equipment costs associated with the relevant transportation or distribution company.

B.3 LNG terminals and storage facilities

The liquefied natural gas ("LNG") terminal in the southern part of Klaipėda Seaport is operated by Klaipėdos Nafta AB. The terminal commenced operations in December 2014 and is one of the most important facilities in Lithuania that ensures national energy security.

The Government is in charge of setting the minimum annual amount of natural gas being gasified to ensure stable gasification. The fulfilment of such obligation is to be ensured by the supplier appointed by the Ministry of Energy in the tender procedure. The appointed supplier must not be engaged in transmission and distribution, and its management and organisational structure must not contradict the requirements of unbundling and independence in the natural gas sector.

Under the Law on the LNG Terminal, the costs incurred during the construction and operation of the LNG terminal and the supporting infrastructure can be passed on to consumers for natural gas transmission services in the price of natural gas transmission, according to the rules defined by the Lithuanian

Energy and Climate Policy ("ECP") Commission, the Law on Energy and the Law on Natural Gas.

The Law on LNG Terminal establishes that the right to use the infrastructure of the LNG Terminal is to be ensured without prejudice. This right can be executed on the basis of bilateral agreements between companies using natural gas and the operator of the LNG terminal. Following the requirements set by the NERC, the LNG operator must adopt the rules of using the LNG terminal. The right to use the infrastructure of the LNG Terminal can be limited if the NERC adopts an exception applicable to the new infrastructure of natural gas under Article 53 of the Law on Natural Gas.

B.4 Tariff regulation

The charging methodology is approved by the NERC, which also sets and alters the uppermost limits of prices, and sets requirements to separate the costs and accounting of the regulated activity in order to prevent the cross-subsidising of activities. The uppermost limits of prices are set for five years and can be altered once a year.

The specific transmission, liquefaction, storage and distribution prices that are kept below the set price caps are fixed by natural gas undertakings on an annual basis. The NERC will give instructions to natural gas undertakings in relation to the calculation of specific prices and tariffs if the ECP Commission verifies and determines that:

- prices and/or tariffs set for household customers are calculated in breach of the requirements for setting prices and/or tariffs laid down in methodologies for the calculation of set price caps; and
- that they discriminate against customers and/or are false.

Natural gas undertakings must adjust the prices and/or tariffs within 15 days. Where natural gas undertakings fail to comply with NERC's requirement, the NERC shall, at its own discretion, set specific prices and/or tariffs.

B.5 Market entry

Gas undertakings must hold a licence issued by the NERC for transportation, distribution, storage, liquefaction, market operation, and authorisation for supply.

Furthermore, a licence for the construction of a gas pipeline crossing the Lithuanian border may only be issued with approval from the Government.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

To safeguard security of supply, the Government has established the minimum gas supply security requirements, the gas supply priorities in the event of a gas supply disruption and non-discriminatory gas supply control and funding procedures.

Gas suppliers are responsible for the uninterrupted supply of gas to vulnerable consumers, such suppliers must accumulate and store gas reserves.

Smart metering

The gas distribution network operator has prepared a cost-benefit analysis based on five scenarios for the implementation of a smart metering system for natural gas in Lithuania. In each scenario, the company assessed: quantities and types of equipment (meters), consumer consumption, service costs, and economic and social benefits. NERC, which considered the operator's arguments and the assessment, confirmed that the deployment scenarios presented and the assumptions modelled do not generate sufficient financial and socio-economic returns. As a result, the legislation currently requires the operator to install remote data collection systems at all metering points where gas consumption exceeds 100,000m^3 per year.

B.7 Cross-border interconnectors

The Lithuanian gas transmission system is connected to the Klaipėda LNG terminal, the systems of Lithuanian gas DSOs, as well as to the gas transmission systems of four countries: Latvia, Belarus, Poland, and Russia (the Kaliningrad region).

The Lithuanian natural gas market (like the markets of the other Baltic States and the Finnish market) are isolated from the EU's single market for natural gas. This problem will be resolved by the Gas Interconnection Poland-Lithuania (GIPL) project, which was successfully completed (and became operational) on 1 May 2022. This project will allow Lithuania to become an important (if not the most important) gas transit and trading hub for the Baltic States and Finland, and will also increase competition, liquidity, the diversification of sources and routes of supply in the Lithuanian and other natural gas markets within the region. This will create opportunities to exploit the potential of the LNG Terminal in Klaipėda not only for the needs of consumers in the Baltic States, but also for Polish and Ukrainian consumers, thus increasing the security of natural gas supply in the region.

C. Energy trading

C.1 Electricity trading

Trading in physical electricity on the Lithuanian market is conducted in two ways, ie traded on the basis of bilateral agreements and traded on the electricity exchange.

Electricity market rules, approved by Order No. 1-378 of the Minister of Energy of the Republic of Lithuania on 29 December 2021 ("Market Rules"), regulate electricity trading in Lithuania. These Market Rules provide that market participants trade electricity on the electricity market on the basis of bilateral contracts and/or on the electricity exchange.

International trading, which is advance trading, takes place on the exchange; all electricity supply contracts are concluded ahead of consumption. The market participants may choose between two trading methods, ie the day-ahead trading ("Elspot") or intraday trading ("Elbas"). Electricity trading on the exchange is performed by the market participants, who are registered in a database at the electricity exchange operator. The trading is conducted for each hour of the future period individually (hourly trading). The trading currency in the Lithuanian bidding area is the Euro. The trading on Nord Pool is governed and regulated through a detailed rulebook. The rulebook is a set of private law agreements applying to all parties involved in trading and related activities.

Legislation does not prohibit using International Swaps and Derivatives Association/European Federation of Energy Traders ("ISDA/EFET") contracts; however, it is normal practice in the

Lithuanian wholesale market to conclude free-form written contracts for the purchase and sale of electricity.

The TSO ensures and maintains a balance of power generation and consumption, and organises trading in balancing power. The TSO ensures and maintains a balance of power generation and consumption and organises trading in balancing power, which is electricity generated not according to electricity consumption or generation schedules compiled in advance. Participants in the electricity market that have concluded an agreement on the sale and purchase of balancing power with the TSO become the responsible 'balancing' party.

C.2 Gas trading

Rules on the Trade in Natural Gas, approved by Order No. 1-293 of the Minister of Energy of the Republic of Lithuania on 28 November 2011 ("Rules on the Trade in Natural Gas") establish that the trade in natural gas is performed in the following ways:

- on the basis of sale and purchase agreements: gas is traded by the supply companies with consumers, other supply companies and/or system operators;
- on the basis of sale and purchase agreements and service contracts: gas is traded by the supply companies and DSOs (in the case of guaranteed supply) with consumers; and
- buying and selling gas on the gas exchange: trade market participants, who are in compliance with the requirements established by the Rules on the Trade in Natural Gas and registered with the gas exchanged; and
- gas trading is performed by energy units, ie megawatt hours ("MWh").

Until the end of 2014, gas was imported from one supplier, OAO Gazprom. In late 2014, the LNG terminal, which is based on the floating storage and regasification unit ("FSRU") and provided by Höegh LNG, commenced operations. Seeking full energy independence from Russian gas following the conflict in Ukraine, Lithuania has completely abandoned Russian gas. Lithuania's gas transmission system has been operating without Russian gas imports since the beginning of April 2022. All Lithuanian gas demand is satisfied through the LNG terminal. If necessary, gas can also be delivered to Lithuania via the gas link with Latvia, and from 1 May 2022, through the gas link with Poland.

The trade in gas on the gas exchange is to be executed according to legislative requirements, including but not limited to the Law on Natural Gas and Rules on the Trade in Natural Gas. Trading gas on the gas exchange is organised at the place of trading. All participants of the exchange have the right to sell and purchase the gas. On the gas exchange, it is only possible to sell the amount of gas that was acquired by the participant of the exchange under the sale and purchase agreement and/or on the gas exchange.

The TSO is responsible for the natural gas transmission system balancing, which ensures the safe and efficient operation of the transmission system. The primary responsibility for natural gas balancing falls on market participants involved in balancing the transmission system that must offset the amount of gas off-taken from the transmission system by injecting the same amount of gas into the transmission system during the balancing period. However, the ultimate responsibility for the balanced transmission system operation falls on the TSO.

Where market participants cause imbalance to the system, they must either buy gas from the TSO or sell it to the TSO, depending on whether they caused the storage or excess of gas in the transmission system. If market participants involved in balancing the transmission system exceed the allowed tolerance limits of the imbalance, they must pay an imbalance payment.

D. Nuclear energy

Lithuania does not have any operational nuclear power reactors. Lithuania previously operated two RBMK reactors at Ignalina Nuclear Power Plant ("INPP"). The thermal power output of one unit of the INPP was 4,800MW and its electrical power capacity was 1,500MW, both of which were shut down in 2004 and 2009.

At the end of April 2022, the 190th and last cask of spent nuclear fuel was taken to the new interim spent fuel storage facility at the INPP. This is an important phase in the decommissioning of the plant, which began in 2016 and is now on the way to being successfully completed.

E. Upstream

The Law on the Subsoil establishes the regulatory framework for hydrocarbon upstream activity in Lithuania. It sets out that the subsoil is the exclusive property of the state. The basis of the exploitation of natural resources is the right to explore and/or extract, which may be granted to legal entities or individuals.

Exploration of the subsoil, and exploitation and protection of its resources, is organised and coordinated by the Government or the institution authorised by it. The Ministry of Environment is responsible for implementing the state strategy for the protection and utilisation of the subsoil as well as control of the exploitation and protection of natural resources. The Lithuanian Geological Service is responsible for state geological surveys, regulation of the utilisation and protection of the subsoil, control of direct and remote exploration, and management of the state geological information system. Municipal institutions also regulate the utilisation and protection of the subsoil.

Authorisation must be obtained for the following activities: (i) exploration of the subsoil; and (ii) extraction of hydrocarbons.

Authorisation for the direct and remote exploration of subsoil is issued by the Lithuanian Geological Service or the Government. The authorisation may be granted to legal entities and individuals or a group thereof acting in partnership and with at least three years of experience during the previous seven years in the field of exploration of the subsoil. Exploration of the subsoil of all types must be registered with the Lithuanian Geological Service except for indirect explorations financed from private sources. Prior to the commencement of direct exploration, it must be reported to the board of the municipality where the exploration is planned. Such exploration will also be coordinated with the owners and users of the land. Authorisation for exploration of the subsoil is granted for an unlimited period.

Authorisation for the extraction of hydrocarbons is issued by the Government or authorised institution on the basis of a public tender. The authorisation may be granted to legal entities and individuals or a group thereof acting in partnership. The Government can set additional tender specifications for participants. All authorisations for the extraction of hydrocarbons must be registered with the institution that issued the authorisation. The extraction of hydrocarbons is permitted only after the contract of extraction and the project of extraction are executed. The contract of extraction is concluded between the winner of the public tender and the Ministry of Environment. The limits for the amount of hydrocarbons to be extracted, which are established by the Government or other state institutions, will be indicated in the extraction contract. The project of extraction will be coordinated with the competent institutions and approved by the institution authorised by the Ministry of the Environment. The Government or authorised institution may revoke the authorisation for the extraction of hydrocarbons on a number of grounds, including state interests. In this case, the person with the authorisation will be compensated for their losses.

Authorisation for the extraction of hydrocarbons is granted for a limited period. The owner or user of the land plot has the right to extract hydrocarbons for his own needs, but not for sale, without an authorisation.

Exploration and extraction of oil is the only upstream hydrocarbon activity currently taking place in Lithuania.

F. Renewable energy

F.1 Renewable energy

Following comprehensive targeted investments and market restructuring, Lithuania is now well on its way to ensuring that its major energy outlines are achieved by 2025. This is evident from its impressive fiscal run across the stretch of the pandemic period.

It is also worth mentioning that Lithuania is among the leaders in the development of renewable energy in the EU: together with Denmark, Estonia, Spain and Portugal, it is among the five most ambitious countries in the EU by renewable energy targets (Lithuania is projected to have 45% of its electricity coming from RES by 2030). By building several interconnections with the Western European electricity system, converting district heating systems to the use of biofuels, approving additional auctions for the generation of solar and wind electricity and by promoting prosumer policy, Lithuania will have the potential to exceed 1.5 times the EU's overall clean energy generation target.

F.2 Renewable pre-qualifications

Projects willing to participate in an auction must sign the protocol of intentions and preconditions to connect to the electricity grid. While signing preconditions to connect, a project developer must pay a security obligation fee which is equal to €15/kW of installed capacity.

If the project meets the prequalification requirements it is allowed to participate. Auction procedures could last up to 180 days. After winning the auction, a project developer has 90 days to get the permit to develop electricity generation capacities. After the permit is issued, the project developer has three years to complete the project works (it may be possible to prolong the period by up to one year).

F.3 Biofuel

The Government is promoting and attempting to create a favourable environment for the production and utilisation of biofuel in the transport sector in Lithuania. Under the National Energy Independence Strategy of 26 June 2012, Lithuania's target is to achieve 15% by 2030 (in cities, there should be 50% fewer cars running on traditional fuel, ie petroleum and diesel) and 50% by 2050 (100% fewer cars running on traditional fuel in cities).

G. Climate change and sustainability

G.1 Climate change initiatives

As a responsible member of the EU, Lithuania is complying with all the commitments undertaken for the purpose of implementing the United Nations Goals for Sustainable Development and the Paris Agreement on Climate Change. These commitments cover, in principle, three tasks to be completed by 2030: bringing down greenhouse gas (GHG) emissions by 40% (compared to 2005); improving energy efficiency by at least 32.5% and increasing the share of RES in the overall energy mix up to 32%.

According to the National Climate Change Management Agenda, prepared in close consultation with social and economic partners, associations, and the public, the planned measures will require €14 billion, with possibly €9.6 billion coming from public funds. Most of the funds (about €10.8 billion) will be allocated for the implementation of the national energy independence objectives and Lithuania's commitments to the EU on mitigating the impact of climate change and thereby promoting cross-sectoral technological and operational changes.

Lithuania is also planning to allocate €3.3 billion to climate change adaptation. All the attention and 50% of the funds will be dedicated to the projects of infrastructure resilience in a time of continuous climatic change. The plan provides for the construction of resilient road surfaces and projects for the resilience of electricity distribution infrastructure and rainwater management. It encourages agricultural insurance and organic and climate-resilient farming. The plans are to implement measures for public health, management of extreme events, the introduction of innovations, forestry, ecosystems, biodiversity and the landscape, as well as other sectors. Most of these funds will come from EU funds and the national budget. The money will be used to implement technological changes needed to mitigate the impact of climate change in different sectors.

G.2 Emission trading

Lithuania has cut carbon dioxide ("CO_2") emissions by 57% compared to 1990, which is among the best results in the EU. National measures to achieve compliance with the commitments under the Kyoto Protocol and the EU climate change requirements have been implemented through a company level system for trading in EUAs.

G.3 Carbon pricing

The carbon pricing mechanism is not yet applicable within Lithuania. According to Government representatives, this mechanism will start operating as soon as possible for goods relevant to Lithuania, in particular, fertilisers, cement and electricity. However, the representatives believe that the application of this mechanism in the energy sector could be difficult. As such, the Government will begin with areas where carbon emissions can be clearly calculated.

G.4 Capacity markets

The development and implementation of the capacity mechanism are particularly important in implementing the objectives of the Lithuanian National Energy Independence Strategy related to the development of power generation from RES, increasing local power generation within the country and reducing of electricity imports and smooth synchronisation of the Lithuanian power system with the continental European power system.

The capacity mechanism will be implemented in Lithuania by organising technology-neutral capacity auctions, meaning that the auctions will be open not only to electricity generating units, but also to storage (such as batteries) facilities and independent electricity demand response aggregators, and the participants will be able to use not only existing but also future generation facilities to be installed by the launch of the capacity delivery period. Electricity consumers managing demand response facilities will be able to participate in capacity auctions and become capacity suppliers (ie they will be able to take advantage of the capacity mechanism themselves). The new facilities are expected to replace technologically obsolete, inefficient and non-compliant facilities. It would also contribute to climate change mitigation goals.

The capacity mechanism will also be open to other EU Member States, with power systems connected to the Lithuanian power system via an interconnector (or interconnectors), natural persons or legal entities, other organisations or their subdivisions operating existing capacity facilities in that Member State. This will ensure greater competition and attract a larger number of participants.

H. Energy transition

H.1 Overview

The carbon intensity of electricity and heat generation has decreased over the past decade, and Lithuania is now comparable with leading EU countries when it comes to the share of renewables in final energy consumption. The Ignalina nuclear power plant was shut down at the very end of 2009, forcing Lithuania to boost electricity imports, although domestic clean power generation is rising fast. Biomass provides 80% of district heat, onshore wind is growing, and Lithuania's unique net metering system is driving fast growth in clean distributed energy.

Lithuania has set a target of having 100% of electricity from RES by 2050, which will require electricity systems and markets to accommodate very high shares of variable renewable energy, notably onshore and offshore wind.

H.2 Renewable fuels

Hydrogen

According to its National Energy and Climate Action Plan ("NECP"), Lithuania considers hydrogen 'a promising area for energy innovation and an opportunity to acquire new energy competencies'. Launching a hydrogen market would allow 'the capitalisation of research efforts, the creation of new businesses, economic growth and exportation opportunities'.

Lithuania joined the Hydrogen Initiative set up by EU Energy Ministers in Austria in September 2018. In its 2018 National Energy Independence Strategy, Lithuania expects that 'the share of renewable electricity will continue to increase and, gradually, alternative fuels for transport, including hydrogen, will be deployed'.

Lithuania has an enabling environment to address the deployment of renewable hydrogen, mainly in the transport sector, given its research and development activities and its commitment to building large variable renewable electricity capacities, whose integration in the electricity system could be facilitated by power-to-x deployment. Lithuania intends to be involved in the extension of the H2GO4 IPCEI project. It was not involved in the HyLAW project, and could possibly carry out a similar assessment to identify and address its national specific barriers to the deployment of hydrogen.

Lithuania seems to consider hydrogen applications mainly from a research, development and innovation (RD&I) perspective. However, Lithuania's NECP does not include specific objectives or targets for the production or use of hydrogen, nor hydrogen specific policies or measures.

Ammonia

Ammonia is not currently used as a renewable fuel in Lithuania.

H.3 Carbon capture and storage

The implementation the Lithuania's main objectives in the development of new energy technologies (reduce existing RES costs, establish better conditions for efficient use of energy, etc) requires the accelerated development of RES, such as carbon capture and storage (CCS) technologies.

Although Lithuanian legislation regulates in detail the conditions for the geological storage of CO_2, specific applications of this technology in Lithuania are still at the planning stage.

H.4 Oil and gas platform electrification

Although the Lithuanian economy currently relies heavily on gas and oil, these are all technologies of the past; Lithuania will experience a decline in the popularity of gas and oil over time (since the Green Deal initiative in Lithuania and Europe has already led regulators and market participants to focus on the development of clean technologies).

One of these is pure hydrogen technology, which involves the production of hydrogen via electrolysis from RES and from fossil fuels, with CO_2 capture. In the strategic sector documents, Lithuania intends to integrate hydrogen through decarbonisation of the industry, transport, energy and buildings sectors. Notably, this technology and its market are in the development phase, so the market and regulators should start preparing for the application of these technologies. Hopefully, the actors involved in the development of this technology and the market, both national and EU institutions, as well as market participants themselves (generators, transmission and distribution network operators, and others), will have a unified approach and coordinate their actions to create an environment conducive to the realisation of the potential of new technologies, covering both investment and harmonious legal regulation, or the creation of an efficient market, research and innovation.

H.5 Industrial hubs

Lithuania's Free Trade Zones (industrial hubs), known more commonly as Free Economic Zones ("FEZs"), comprise of seven FEZs. Activities conducted in a FEZ include commercial, production and export, banking, business and research activities.

A FEZ in Lithuania is a designated area for commercial and financial activities that abides by the Republic of Lithuania Law on the Fundamentals of Free Economic Zones. Since the FEZ is regarded as an area outside Lithuania, goods within the FEZ will be charged import and export duties instead.

Located in Lithuania's core economic centres, the country's seven FEZs offer very favourable conditions for doing business: from ready-to-build industrial sites with all the physical and legal infrastructure in place, to facilities to lease, plus a range of support services and tax incentives (businesses choosing to locate at these zones enjoy 0% corporate profit tax during their first ten years of operation and only 7.5% tax over the next six years; also, tax on dividends and real estate tax are not applicable).

H.6 Smart cities

The idea and regulation of smart cities in Lithuania is currently at a preliminary stage; however, the state-approved spatial planning guidelines already foresee that, in the context of the ongoing digitalisation processes and advances in technological development, Lithuania's master plan solutions should be implemented through various smart city systems and applications. It might be mentioned that Lithuania's capital city, Vilnius, in responding to mobility challenges, has developed a traffic monitoring system that connects all traffic lights across the city into one centrally-managed network. The new system allows the city to cut average travel times, despite the number of cars in Vilnius increasing by 40% over the last decade. Also, Vilnius has modernised its public transport, introducing e-tickets, redrawing bus and trolleybus route plans and optimising the network with the help of 'fast buses'.

I. Environmental, social and governance (ESG)

Most of the Lithuanian companies in the energy sector (eg Ignitis Group, EPSO-G, Enefit, others) emphasise the importance of decarbonising the sector, the modernisation of the energy system, the expansion of renewable energy, the development of innovative solutions and sustainable growth while adhering to the principles of environmental protection, social responsibility and good corporate governance.

In our view, the monitoring of relevant indicators and open communication of progress are increasingly becoming integral to sustainability activities. Market players aim to provide detailed information on the implementation of their sustainability activities and follow international requirements and standards in preparing public reports. We hope that in the future this will become a usual practice for every market participant.

Energy law in Luxembourg

Recent developments in the Luxembourg energy market

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Ambitious Energy and Climate Plan

In May 2020, the Government of Luxembourg (“Government”) published and submitted to the European Commission (“Commission”) its “Integrated National Energy and Climate Plan for 2021-2030” (“NECP”) in accordance with the Regulation on the governance of the energy union and climate action (EU/2018/1999).[1] The plan sets out a series of policy goals, ranging from the transfer to renewable energy sources (RES) (above current decarbonisation efforts) to far reaching energy efficiency targets up until 2030. After issuing a list of nine preliminary remarks and recommendations in June 2019, the Commission published its final and exhaustive assessment on the draft plan in October 2020.[2]

By 2030, Luxembourg is committed to reducing non-ETS greenhouse gas ("GHG") emissions by 55% compared to the 2005 reference year whilst complying with the land use, land use change and forestry no debit commitment (“LULUCF”). This target exceeds the goals set out in the Effort Sharing Regulation ("ESR") by 15 percentage points. The report notes that GHG emissions should primarily be reduced by a country-wide transition towards electro mobility, new measures and incentives in the construction and building sector, and an expanding (and free) public transportation network. The Commission acknowledged the ambitious national target, while noting that the NECP could have offered more detail on the interaction of the GHG emission reduction measures with climate change adaptation goals.[3]

From a share of 11% in 2020, Luxembourg anticipates ramping up the contribution of renewable energy to gross final energy consumption to 25% by 2030. This exceeds the 22% minimum threshold deriving from the reference formula in Regulation (EU) 2018/1999 and should be reached by consistently developing wind and solar energy, heat pumps, deep geothermal energy and green hydrogen sources. As these domestic renewable energy developments should make up for only 19.6% of the overall target, the Government intends to meet the 25% commitment by participating in transnational joint projects, including joint tenders for photovoltaic ("PV") and wind capacity with neighbouring countries and the new European Union ("EU") Renewable Finance Platform. The Commission notes in its assessment that the national renewable energy goals do not only require direct measures to accelerate the deployment of renewable energies, but also clear action on energy efficiency.[4]

In this respect, the Government commits to reducing final energy consumption by 40 to 44%, translating to 35.568GWh by 2030. A key driver for energy efficiency improvements will be an action plan in the housing and buildings sector, including:

- the renovation of existing housing stock;
- a push for low-energy and energy-plus buildings by law for residential and single purpose buildings (also including social housing); and
- the development of a large energy efficiency investment market for industry, SMEs, and large office buildings.

The NECP explicitly sets out the long-term goal of renovating all existing houses to net zero emissions by 2050. Overall, the Commission notes that while certain plans and policy measures cannot be precisely quantified and evaluated, the overarching efficiency target is sufficient.[5]

The NECP also explains the Luxembourg climate pact, through which the Government works with the country’s 102 municipalities to launch projects and align on best practices to ensure that the formulated goals of the NECP can be reached by 2030. The climate pact has initially been set up in 2012 and is designed to offer technical advice and financial support for climate actions by municipalities, which can receive certification and funding from the Luxembourg state by implementing projects relating to, among other things, circular economy and air quality. The Commission considered this effort to be a good practice, laying the groundwork for a sustainable nation-wide green energy transition.[6]

Law of 3 February 2021 – renewables self-consumers

On 3 February 2021, the Luxembourg parliament adopted a long-awaited amendment of the Law of 1 August 2007 on the organisation of the electricity market. Following a legislative process of almost three years, the law of 3 February 2021 promotes the decentralisation of electricity generation from plants using fossil fuels to locally generated renewable energy. The law also provides for a digital platform that should gather and centrally store data provided by the operators of electricity distribution networks facilitating the development of services and products for consumers.[7]

Most importantly, the law of 3 February 2021 regulates, in line with RED II, energy production and consumption of so-called 'renewables self-consumers' and 'renewable energy communities'. Whereas the draft law[8] initially foresaw a distinction between local and virtual self-consuming communities, the legislator aborted this distinction and aligned national law with the definitions laid down in RED II.

† Deceased.

As enshrined in the Directive, the law of 3 February 2021 enables renewable energy self-consumers located in the same building or building block to generate renewable energy for their own consumption while also being allowed to store and sell excess production through power purchase agreements, electricity suppliers, and peer-to-peer trading arrangements. Importantly, these activities do not require, as initially foreseen in the draft bill from March 2018, the creation of a legal entity.[9]

Renewable energy communities must be set up as legal entities, to which natural persons, SMEs or local authorities (including municipalities) can accede. Additionally, members of one renewable energy community must be located in the same district or area of the relevant transformer station.[10] The Luxembourg legislator implements the formulated goal of RED II to 'promote and facilitate the development of renewable energy communities', by allowing such entities to resort to a standard contract with the distribution network operators as drawn up in cooperation with the National Regulation Authority (Institut Luxembourgeois de Régulation) ("ILR"). The distribution network operators are also entrusted with the allocation of energy generated by a renewable energy community, unless it assumes this task for itself or resorts to a sub-contractor.[11]

Law of 3 June 2021 – renewal of the energy saving scheme

On 3 June 2021, four months after the first legislative reform of the law of 1 August 2007, the Luxembourg Parliament passed a second bill, providing for an extension and expansion of the legislative framework for energy saving obligations on energy suppliers and final consumers. The law of 3 June 2021 explicitly refers to the ambitious energy efficiency targets of the NECP until 2030 and applies to electricity and gas suppliers alike. It transposes the relevant provisions of updated Energy Efficiency Directive ("EE Directive") and the newly set EU wide energy efficiency targets.[12]

Although the updated EE Directive requires Member States to reach annual energy efficiency improvements of at least 0.8%, Luxembourg intends to surpass this level with savings of between 1.2 and 1.5%. As for the now replaced law of 2015, the law of 3 June 2021 only designates natural gas and electricity suppliers as obligated parties within the relevant articles of the Directive. The draft bill explicitly encouraged energy suppliers to incentivise final end consumers to utilise energy efficiency savings; the law does not create direct obligations or financial incentives for end consumers. Administrative penalties can be imposed by the ILR on electricity and natural gas suppliers that do not achieve the annual energy savings required by the updated legal framework.

Amendments to national legislation – energy efficiency standards for new buildings

Relating to the energy efficiency goals formulated in the NECP for the housing sector, the Luxembourg Government passed the Grand Ducal Regulation of 9 June 2021, concerning the energy performance of buildings to consolidate national energy efficiency standards for residential and commercial buildings, while also transposing the updated EU Directive 2018/844 on Energy Performance of Buildings ("EPB Directive").

Covid 19 – short term measures and green subsidies

A series of transitionary legislative instruments have been adopted to:

- temper the consequences of the Covid-19 crisis; and
- to re-start economic activity with incentives for energy efficient innovation and to accelerate the development towards national and European climate goals.

As a direct response to the Covid-19 crisis, the Government temporarily extended a series of deadlines for the national regulator ILR and adapted the consultation and publication schedule of a series of guidelines for energy actors.[13] Additionally, and as in various member states, the Government decided to support services of general economic interest ("SGEIs") by a compensation mechanism for costs caused, during the period of the crisis, using energy efficiency measures.[14]

In line with the priorities of the European Commission recovery plan, the Government also established funds and subsidy schemes to incentivise projects to improve energy efficiency. The reform package called 'Neistart Lëtzebuerg'[15] attempts to impede the deterioration of the Covid-19 investment climate. In this respect, the Government decided, amongst other measures, to contribute up to 50% for the eligible costs for industrial energy efficiency projects while supporting investments into circular economy projects by contributing to up to 30% of the eligible costs. In April 2021, the government the extension of the scheme until the end of 2021 while also increasing the maximum aid eligibility to €1.8 million as opposed to €0.8 million.

This support for green investments in the industrial sector is paired with an increase of the subsidy levels for energy renovations of domestic housing. The Government increased available funding and aid intensity to incentivise private households to develop concepts and so-called 'accords de principes'[16] which could then qualify for financial state support. The Government gave insight into the reception and success of the aid scheme by responding to a parliamentary question in March 2021.[17] The response states that while a significant number of applications for the new (increased) subsidies was still undergoing review and processing, more than €10.7 million in grants were awarded as of 1 June 2020.

Push for green hydrogen technology

The Luxembourg NECP also places importance on the production and use of green hydrogen energy; hydrogen produced by electrolysis of demineralised water using PV or wind power sources. In this area, the Luxembourg Institute of Science and Technology ("LIST") is looking closely into developing, storing and deploying such green energy across Luxembourg and joining ten other EU member states in working together towards an interconnected infrastructure and efficient use of hydrogen energy across the EU.[18]

On 27 September 2021, the Luxembourg Ministry of Energy and Spatial Planning published an extensive strategy paper as to the development and increasing use of hydrogen in Luxembourg.[19]

The paper underlines the great potential in Luxembourg to capitalise on hydrogen energy to reduce GHG emissions by up to two million tonnes of carbon dioxide ("CO_2") per year. This decarbonisation effort, by means of an increasing reliance on green hydrogen, should be achieved especially in three priority sectors, namely:

- industry;
- transport; and
- a future-proof integrated energy system.[20]

In its strategy paper, the Ministry proposes and explains in detail seven measures to promote the production, import and use of renewable energy.

First, Luxembourg pledges to contribute to a legal and regulatory framework on EU level which should strive to certify and promote (strictly green and renewable) hydrogen sources while developing storage and distribution infrastructure across Europe.[21]

Second, the Ministry stresses the importance to cooperate with international partners and third countries, focussing especially on production and cross-border hydrogen supply infrastructure in neighbouring countries.[22]

Third, and as suggested above, research and innovation, also by means of increased dedicated funding to the LIST,[23] should foster the deployment and identification of opportunities for hydrogen use in Luxembourg.[24]

Fourth, with the title of 'materialising flagship projects', the Ministry announces a series of punctual initiatives ranging from the installation of a first hydrogen refilling station, to decarbonisation studies on industrial process and the methanation of CO_2 contained in Biogas.[25]

Fifth, the Luxembourg hydrogen strategy identifies the aforementioned priority sectors as primary and most efficient hydrogen targets given their otherwise difficult electrification and decarbonisation.[26]

Sixth, the Ministry plans to develop instruments, in line with European rules, to establish a functioning hydrogen market with stimulated supply and demand for renewable hydrogen.[27]

Seventh, and lastly, the Ministry intends to put in place a hydrogen-taskforce that continuously pushes forward and safeguards the implementation of the strategy.[28]

Therefore, while it appears as if first concrete steps are undertaken towards increasingly relying on hydrogen energy, a concrete legislative framework is yet to be developed and implemented.

Endnotes

1. Integrierter nationaler Energie- und Klimaplan Luxemburgs für den Zeitraum 2021-2030 gemäß der Verordnung (EU) 2018/1999 des europäischen Parlaments und des Rates vom 11 Dezember 2018, as notified to the European Commission on 29 May 2020.
2. European Commission Staff Working Document – Assessment of the final national energy and climate plan of Luxembourg, 14 October 2020, SWD (2020) 915 final (European Commission assessment of Luxembourg NECP).
3. See European Commission assessment of Luxembourg NECP, p.13.
4. See European Commission assessment of Luxembourg NECP, p.8.
5. See European Commission assessment of Luxembourg NECP, p.9.
6. See European Commission assessment of Luxembourg NECP, p.13.
7. Loi du 3 février 2021 modifiant la loi modifiée du 1er août 2007 relative à l'organisation du marché de l'électricité (February 2021 Electricity Law).
8. Projet de loi modifiant la loi modifiée du ler août 2007 relative à l'organisation du marché de l'électricité, as submitted to the State Council on 8 March 2018 (Ref - L5452).
9. Ibid.
10. See February 2021 Electricity law, Article 1(6).
11. See February 2021 Electricity law, Articles 6 (Articles 8 quater, (5, 6)).
12. Loi du 3 juin 2021 portant modification : 1° de la loi modifiée du Ier août 2007 relative à l'organisation du marché de l'électricité ; 2° de la loi modifiée du Ier août 2007 relative à l'organisation du marché du gaz naturel (June 2021 Energy Law).
13. Règlement grand-ducal du 8 avril 2020 relatif aux mesures temporaires dans les secteurs de l'électricité et du gaz naturel dans le cadre de la lutte contre le Covid-19 (no longer in force).
14. Règlement grand-ducal du 19 août 2020 relatif au fonctionnement du mécanisme de compensation du service d'intérêt économique général en matière d'efficacité énergétique temporairement mis en œuvre en vue de renforcer les activités d'économies d'énergie dans le contexte de la relance de l'activité économique entre le 1er juin 2020 et le 31 décembre 2020.
15. See Press release of the Luxembourg government, see: www.gouvernement.lu/fr/actualites/toutes_actualites/communiques/2020/05-mai/20-neistart-relance.html.
16. Ibid.
17. Parliamentary question by Déi Lénk, David Wagner, submitted on 1 February 2021 under reference number 3555 and as responded to by the government on 9 March 2021.
18. Financial Times, 'Luxembourg wants to turn hydrogen green', 16 February 2021, see: www.ft.com/content/54569cdc-7af3-4e2f-b834-d3160e2ca999.
19. The Luxembourg Government, Ministry of Energy and Spatial Planning, *Stratégie hydrogène du Luxembourg*, Pit Losch and Georges Reding, as presented in a press release dated 27 September, 2021, accessible under: (Hydrogen Strategy Paper).
20. See Hydrogen Strategy Paper, p.2.
21. See Hydrogen Strategy Paper, p.15.
22. See Hydrogen Strategy Paper, p.17.
23. See Hydrogen Strategy Paper, p.20.
24. See Hydrogen Strategy Paper, p.19.
25. See Hydrogen Strategy Paper, p.23.
26. See Hydrogen Strategy Paper, p.25
27. See Hydrogen Strategy Paper, p.26
28. See Hydrogen Strategy Paper, p.28.

Overview of the legal and regulatory framework in Luxembourg

A. Electricity

A.1 Industry structure

Nature of the market

The Luxembourg electricity market has been fully liberalised since 1 July 2007. Since then, residential consumers have been free to choose their energy supplier and supply prices are unregulated. On the retail market for electricity supply, the switching rates remain low for residential and professional consumers. In 2021, the switching rate was 2.6% in terms of volume of electricity consumed and 0.3% in terms of number of clients.[1]

Figures published by the Luxembourg Regulatory Authority (*Institut Luxembourgeois de Régulation*) ("ILR") for 2021 show there are few foreign suppliers on the market. In the past, the ILR explained the lack of market entry from foreign suppliers by referring to the following factors:

- Limited number of customers (330,695 points of supply in 2021);[2]
- Language barriers; and
- Interconnection between historic players and neighbouring suppliers.

Key market players

Enovos ("Enovos") and Creos ("Creos") are the dominant players in the Luxembourg energy market. These two companies are the result of a fundamental restructuring of the Luxembourg energy market which took place in 2009, with the merger of three historic players of Luxembourg and the surrounding region: Cegedel SA (Luxembourg electricity incumbent), Soteg SA (Luxembourg gas incumbent) and Saar Ferngas AG, a gas distribution company that was majority owned by ArcelorMittal. Enovos is responsible for the production and supply of energy; Creos is a combined electricity and natural gas system operator responsible for the operation, development and maintenance of the transmission and distribution system.

The holding company of both Enovos and Creos is Encevo, formerly named Enovos International, which is established in Luxembourg and is also the holding company of German companies, Enovos Deutschland GmbH (an energy supplier), Creos Deutschland GmbH (a natural gas system operator) and net4energy GmbH (a renewable energy platform). The Luxembourg State is the majority shareholder of Encevo, directly and indirectly holding around 54.2% of its capital. The other main shareholders of this holding company are China Southern Power Grid International (around 24.92%) and the City of Luxembourg (around 15.61%).

In addition to Creos, one other transmission system operator ("TSO") exists in Luxembourg, the Société de Transport d'Energie Electrique du Grand-Duché de Luxembourg S.C. ("Sotel"), which operates a 220kV and a 150kV grid[3] through its unbundled network company Sotel Réseau & Cie, SECS ("Sotel Réseau"). As it is exclusively connected to industrial clients such as ArcelorMittal, Sotel's grid is classified as an industrial grid under Luxembourg law. Sotel Réseau also holds a ministerial concession[4] for operating its grid as an industrial system operator. Together, Creos and Sotel manage two transmission grids, which are not permanently interconnected.

The number of distribution system operators ("DSOs") has decreased from ten to five since 2007 due to several municipalities choosing to transfer their grid operation or ownership (or both) to Creos.

The Luxembourg electricity market is still characterised by its dependence on foreign supply. Only about 18.5% of the electricity consumed in Luxembourg is produced domestically.[5] The largest producer in the country, Société Electrique de l'Our SA ("SEO"),[6] mainly exports its production by injecting into the German grid. SEO operates a pumped storage plant in Vianden that is mainly used for peak power production and currently has a capacity of about 1,300MW.[7] The Luxembourg State and the German RWE Power[8] each hold 40.43% of SEO's capital, with the remaining capital being held by a variety of investors (including Enovos, 4.47%).

Regulatory authorities

The key institutional players in the Luxembourg electricity sector are the Minister for Energy and Spatial Planning ("Minister"), the Government Commissioner of Energy and the ILR. The Law of 1 August 2007 relating to the organisation of the electricity market, as amended, confers powers on these three authorities to supervise and regulate the electricity market.

The Minister grants authorisations to energy undertakings and system operators. The ILR is also responsible for setting and approving the methodology used to calculate transmission and distribution tariffs, among other duties.

The ILR is a public, independent authority established in 1997 as part of the framework for the liberalisation of the telecommunication sector. The ILR's scope of powers includes the regulation of the electricity and gas markets but also the postal, railway, airport and radio frequencies sectors. Following the transposition of the NIS Directive, the ILR is also competent and the single point of contact for cybersecurity of networks (excluding banking and financial market infrastructures, which are under supervision of the Luxembourg Commission de Surveillance du Sector Financier ("CSSF")).[9] The ILR is funded through mandatory contributions made by market operators of the different sectors. The implementation of the Third Electricity Directive into Luxembourg Law further enhanced the independence and powers of the ILR.

The National Energy Council (Conseil National de l'Energie) issues opinions on energy policies; however, it has no regulatory function. The Energy Agency SA (Agence de l'Energie) is a private corporation partly owned by the Luxembourg State and Enovos, which provides notably advisory services relating to renewable energy and energy efficiency.

The Luxembourg State plays an important role in the national energy market. The State is a significant shareholder in the main Luxembourg energy companies and the main promoter of renewable energy and energy efficiency.

Legal framework

The legal framework for the sector is set out in the Law relating to the organisation of the electricity market adopted in 2007 ("Electricity Law 2007").[10] The law originally implemented the Second Electricity Directive and was notably amended by the Law of 7 August 2012 to introduce the Third Electricity Directive into Luxembourg Law. It has recently been amended by the Law of 3 February 2021 as well as the Law of 3 June 2021, transposing notably the recast Electricity Directive and RED II into Luxembourg Law.

Further relevant, national legal provisions include the following, among others:

- Law of 5 August 1993 on the rational use of energy, as amended;
- Grand Ducal Regulation of 31 March 2010 on the compensation mechanism relating to the organisation of the electricity market, as amended;
- Grand Ducal Regulation of 21 June 2010 on the labelling system for electricity, as amended;
- Law of 17 December 2010 on the taxation of energy products, electricity, manufactured tobacco products, alcohol and alcoholic beverages, as amended;
- Grand Ducal Regulation of 26 December 2012 on the production of electricity from high efficiency cogeneration, as amended;
- Grand Ducal Regulation of 1 August 2014 on the production of electricity from renewable sources, as amended;
- Grand Ducal Regulation of 7 August 2015 on the functioning of the obligation mechanism relating to energy efficiency, as amended;
- Grand Ducal Regulation of 3 December 2015 on the public infrastructure relating to electric mobility, as amended;
- Ministerial Regulation of 6 September 2018 setting out the correction factors provided for under Article 27ter, paragraph 5 of Grand Ducal Regulation of 1 August 2014 on the production of electricity from renewable sources;
- Grand Ducal Regulation of 13 November 2018 on the infrastructure relating to alternative sources of fuel and amending the Regulation of 3 December 2015 on the public infrastructure relating to electric mobility;
- Ministerial Regulation of 22 September 2020 fixing a general implementation plan for infrastructure concerning electric mobility; and
- Grand Ducal Regulation of 9 June 2021 on energy performance of buildings.

Implementation of EU electricity directives

As one of the smallest EU Member States and with the associated limited governmental resources, Luxembourg sometimes encounters difficulties in meeting timeframes for the implementation of EU directives. With the Law of 3 February 2021, Luxembourg transposed, in the course of a three year long legislative process, the recast Electricity Directive as well as RED II into national law. The Law of 3 February 2021 has, just like the Directives, the underlying objective to promote the use of energy from renewable sources. Most importantly, the law provides a regulatory framework for auto-consumption of renewable electricity, allowing for the pooling, distribution and the sale of such self-produced energy.

Together with Malta and Cyprus, Luxembourg was one of the EU Member States to whom a nominative derogation from unbundling requirements for small systems was granted. Under Article 66(3) of the recast Electricity Directive, the unbundling requirements in Article 43 do not apply to Luxembourg. As a result, the FOU model is not applicable to Creos and Sotel and they remain part of a vertically integrated undertaking ("VIU"). However, both companies must comply with the provisions of the legal and functional unbundling regime as required already by the Second Electricity Directive. Additionally, the Law of 7 August 2012 introduced special provisions for VIUs that are under the regulation of the ILR in order to ensure that they do not take advantage of their vertical integration and distort competition.

In relation to DSOs, the legislature has used the option provided for in the Second Electricity Directive, allowing Member States to decide not to apply legal unbundling requirements to DSOs serving less than 100,000 connected customers. This possibility for Member States is upheld under the recast Electricity Directive.[11] Despite the exemption available, several DSOs have nonetheless separated their network and commercial activities on a voluntary basis.

A.2 Third party access regime

Access to Luxembourg's national networks must be granted on transparent and non-discriminatory terms to electricity suppliers, producers and clients. TSOs and DSOs are obliged under the Electricity Law 2007 to connect every applicant who requests the connection and who is located in its transmission or distribution zone.

The system operators must publish the technical and financial conditions for the connection to their medium and high voltage grid. These conditions are subject to the prior approval of the ILR. Before the integration of the Third Electricity Directive into domestic law, these conditions had to be approved by the Minister. Since the Law of 7 August 2012 came into effect, formal approval by the Minister is no longer required; rather, the Minister may request the ILR reconsiders its decision on grounds relating to energy policy.

DSOs must also jointly propose the draft conditions on which connection to the low voltage grid will be based. These conditions are also subject to ILR approval.

Except for producers of electricity from renewable sources, TSOs or DSOs can refuse access to an eligible party if the eligible party's network does not have the required capacity.[12] If access to an existing grid is refused, a supplier, producer or eligible client can establish direct lines subject to the granting of a concession by the Minister.[13]

A.3 Market design

The ILR is generally responsible for ensuring non-discrimination, effective competition and the efficient functioning of the electricity market. The main objectives of the ILR are to:

- promote an internal electricity market that is competitive and environmentally sustainable;
- ensure an effective opening of the market for clients and suppliers;
- ensure appropriate conditions for an effective and reliable functioning of the electricity networks and facilitate access to the networks;
- ensure that clients are benefiting from the efficient functioning of the market and contribute to the protection of the consumers; and
- contribute to a high standard of public service and to the protection of vulnerable clients.

In order to fulfil its objectives, the ILR has in particular the following powers:

- regulatory and decision-making powers with regard to tariffs, access conditions to networks and the rules for the functioning of the market;
- supervision power giving the ILR access to all useful information from all the market participants; and
- power to impose administrative sanctions.

A.4 Tariff regulation

Under the Electricity Law 2007,[14] the ILR determines the calculation methodology of the tariffs for the use of the transmission, distribution and industrial networks after a public consultation.

For the period 2021 to 2024, this calculation methodology is fixed by regulation ILR/E20/22 adopted by the ILR on 26 May 2020.

On basis of the methodology fixed by the ILR, network operators must calculate annually their tariffs and submit them for approval to the ILR.

A.5 Market entry

Ministerial authorisations

The requirements for potential new market entrants will depend on the nature of their activity. Producers who wish to begin electricity production must generally obtain an authorisation from the Minister. However, producers of electricity from renewable sources are exempt under certain circumstances.[15]

An undertaking that wishes to supply electricity in Luxembourg must also obtain prior authorisation from the Minister[16], and can generally access the market on basis of the published tariffs for use of the network. No Luxembourg subsidiary is required; however, the applicants for a supply authorisation must be established in a Member State of the EU or the EEA, or in Switzerland.

Licensing regime

The Electricity Law 2007 established a concession regime and provides that the establishment and operation of electric installations intended for the transmission and distribution of electricity are subject to the granting of a concession by the Minister. Article 24 of the Electricity Law 2007 distinguishes between the concessions required for the operation of a transmission network, a distribution network, a direct line and an industrial network.

The generation and supply of electricity in Luxembourg is subject to prior authorisation from the Minister.[17] The construction of facilities for renewable electricity generation with a rated electrical output of less than 10MW is exempt from the need for ministerial authorisation.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Historically, Cegedel[18] had a public service function. It aimed to ensure safe and competitive supply to end users and to diversify its activities in order to encourage the use of renewable energies and cogeneration. Sotel, on the other hand, always operated a private network for the steel industry and never had a PSO.

Currently, the Electricity Law 2007 imposes different obligations on system operators and suppliers in order to guarantee the electricity supply of residential clients (universal service). It also contains special provisions relating to PSOs[19] and foresees a compensation mechanism to fund extra costs incurred by electricity undertakings due to such obligations.[20] These PSOs can be determined by Grand Ducal regulations. The purchasing obligations imposed on TSOs and DSOs to promote energy production from cogeneration or renewable sources constitute PSOs, inscribed in statute.

Smart metering

The Electricity Law imposes an obligation on DSOs to implement smart metering for all final customers, with an implementation/equipment rate of at least 95% by 31 December 2019 for electricity. As of 31 December 2020, this goal had not been fully met, with a 94.7% installation rate.[21] On 31 December 2021, the goal was finally met, with smart meters replacing 95% of electric and gas meters.[22]

Electric vehicles

Additionally, the Law of 7 August 2012 broadened the DSOs tasks by imposing an obligation to deploy a national infrastructure for electric mobility. The Grand Ducal Regulation of 3 December 2015 set the number of public charging stations for electric vehicles at 400, which is quite significant given the small size of Luxembourg and number of inhabitants (about 635,000). The Grand Ducal Regulation of 19 August 2020 promotes and regulates the installation of charging stations on motorway and road service areas, further widening the charging point network and facilitating mid- and long-distance electro mobility. Again, the costs incurred by the DSOs for the deployment of this public infrastructure are taken into account in the tariffs for use of the grids.

A. 7 Cross-border interconnectors

Luxembourg's grids form part of the balancing regime with neighbouring countries. As such, the grids are part of those countries' respective markets.

Creos is connected to the German grid Amprion. Through Sotel's network, Creos is also indirectly and not permanently interconnected with Belgium. In order to increase security of supply and in view of the integration of the EU internal electricity market, Creos has integrated and connected to an existing overhead line a phase shift transformer between its substation in Bascharage and the Belgian border. In the long term, Creos foresees the installation of a 1000MVA cable path.

Sotel, for its part, is connected to the Belgian grid Elia and, since 2013, also to the French grid RTE.

B. Oil and gas

B.1 Industry structure

Nature of the market

As with the Luxembourg electricity market, the Luxembourg gas market is very small. It is also characterised by dependence on imports from Belgium and Germany.[23]

Similarly, the oil (petrol) market relies entirely on imports as there are no refineries in Luxembourg. Imports come mainly from Belgium and are primarily focussed on fuel for vehicles as well as heating and industrial use. Importers are private undertakings, including the multinational petroleum groups active in Luxembourg. Petrol importers must store a certain quantity of petrol in Luxembourg as stipulated by the Law of 10 February 2015 relating to the organisation of the petrol market, as amended, and further specified in the Grand Ducal Regulation of 17 June 2015 implementing Articles 6, 7, 8 and 40 of the latter Law.

Key market players

Before the fundamental restructuring of the Luxembourg energy market in 2009, the main gas market player was Soteg SA, which was created in 1974 to import, transport and develop the grid.[24] Presently, Soteg SA is part of the Encevo group, which includes Enovos and Creos (see section A.1).

Creos operates the sole transmission network that supplies its own DSO, as well as two third party DSOs, namely:

- SUDenergie SA, which is owned by 14 municipalities and distributes gas within those same municipalities (Esch/Alzette, Differdange, Pétange, Schifflange, Sanem, Bascharage, Bettembourg, Kayl, Rumelange, Mondercange, Roeser, Reckange, Dippach and Garnich); and
- Ville de Dudelange, which operates its gas distribution networks in the limited area of Dudelange.

Creos (with its own TSO and DSO) as well as the two third party DSOs have *de facto* monopolies: Creos in respect of import, transport and distribution of gas, and the two third party DSOs in respect of distribution in their respective concession areas. Each entity owns its respective network.

Regulatory authorities

The ILR has similar responsibilities in the gas sector as it does in the electricity sector.[25] Its functions include facilitating non-discriminatory network access and preventing the abuse of a dominant market position by any of the market players. Gas undertakings, which are under the regulation of the ILR, must pay fees in order to cover the costs of the ILR's functions and staff.[26]

The Minister is the competent authority to deliver the required authorisations for gas undertakings. Generally, the institutional players are identical to those in the electricity market. In addition to the Minister and the ILR, the Government Commissioner of Energy, the Agence de l'Energie and MyEnergy GIE also play an important role in the natural gas sector.

Regarding the oil market, petrol importers must notify the Ministry in charge of energy when intending to import petrol into Luxembourg and provide details of their activities.

Legal framework

The gas market is governed by the Gas Law 2007 relating to the organisation of the natural gas market, as amended.[27] Other relevant national regulations are found, among other regulations, in:

- Grand Ducal Regulation of 19 May 2003 on authorisations for the supply of natural gas;
- Grand Ducal Regulation of 15 December 2011 on the generation, remuneration, and marketing of biogas, as amended;
- Grand Ducal Regulation of 1st August 2014 on the production of electricity from renewable sources, as amended; and
- Grand Ducal Regulation of 7 August 2015 on the functioning of the obligation mechanism relating to energy efficiency.

Regarding the oil market, the obligations of operators active in petrol are set out in Law of 10 February 2015 relating to the organisation of the petrol market and Grand Ducal Regulation of 17 June 2015 implementing Articles 6, 7, 8 and 40 of the latter Law.

Implementation of EU gas directives

In accordance with the Second Gas Directive, professional consumers have been free to purchase gas from the supplier of their choice since 1 July 2004. The gas market has been fully liberalised since 1 July 2007. As in the electricity sector, the Third Gas Directive was transposed into national law by Law of 7 August 2012.

The only TSO in Luxembourg (Creos) has been exempted from legal unbundling obligations since July 2009.

In accordance with Article 49(6) of the Third Gas Directive, the unbundling requirements in Article 9 do not apply to Luxembourg as it is one of the Member States granted a nominative derogation for small systems. As a result, the FOU model is not mandatory for Creos, which remains part of a VIU. Creos must however comply with legal and functional requirements since July 2009 and is subject to special supervision by the ILR since 2012 in order to ensure it does not take advantage of its vertical integration and distort competition.[28]

Additionally, the Luxembourg Parliament chose not to impose the legal unbundling requirements on gas DSOs that serve fewer than 100,000 connected customers.[29]

B.2 Third party access regime to gas transportation networks

The third party access regime is regulated by the Gas Law 2007.[30]

The right to access the transportation and distribution systems is legally protected under Article 23 of the Gas Law 2007, which provides that suppliers of natural gas and eligible clients, have a right to access and use the interconnected network on the basis of published tariffs.

Up to 30 September 2015, access to transportation capacities on the Creos network was based on an entry system where the shipper had to subscribe capacities at the entry points of the network and where delivery intervened at the industrial delivery point or the distribution delivery point. No nomination of capacities was required at the industrial or distribution delivery points.

To enhance the integration of the Luxembourg natural gas market into the European market, Creos and the Belgian TSO, Fluxys, created in close cooperation with the respective national authorities a common entry/exit zone. This means that there has been an integrated BeLux market since 1 October 2015. This represents the first natural gas market integration between two EU Member States.

Consequently, the access regime to the Creos transmission system had to be adapted so that the entry points at the Belgian-Luxembourg border have been suppressed and the Zeebrugge Trading Point ("ZTP") has become the natural gas exchange point in the integrated BeLux zone. Natural gas supply to Luxembourg can now be carried out from every interconnection point or hub in the BeLux zone without reserving intermediary transportation capacities.

Balansys SA, a joint venture company between Fluxys and Creos, was formally designated by the Luxembourg Government ("Government") as the balancing operator in charge of the balancing of the Creos network in July 2015. Undertakings wishing to transport natural gas through Luxembourg and Belgium must therefore enter into a contract with Balansys SA with all of the technical and financial details in case actions to remediate imbalance on the grid are taken. These conditions had been approved by the Luxembourg regulator, the ILR, and by Belgium's regulator, CREG, to enable operational implementation throughout the BeLux zone on 1 June 2020.

B.3 LNG terminals and storage facilities

There are currently no liquefied natural gas ("LNG") facilities in Luxembourg.

There is no gas storage activity in Luxembourg except for operational capacities. Suppliers active in Luxembourg ensure on a contractual basis that the required gas storage capacities are available in neighbouring countries.

B.4 Tariff regulation

The tariffs and conditions for the use of the transportation and distribution networks are calculated by the TSO and DSOs in accordance with the methodology fixed by the ILR.[31] The calculated tariffs are subject to an acceptance procedure by the ILR. The Minister can require the ILR to reconsider its decision on grounds relating to energy policy. These tariffs and conditions must be made accessible to the public and must be offered on terms that are transparent, non-discriminatory and cost-based.

The TSO and DSOs must publish the applicable tariffs and conditions for connection to the networks.

Up to 30 September 2015, the tariff for the use of the transportation network corresponded to a unit price per maximum hourly capacity unit subscribed at the entry points per shipper for its entire portfolio.

However, after 1 October 2015, the tariff system needed to be adapted due to the integration of the natural gas market in the BeLux zone (see section B.2). Tariffs are now applied at the exit points.

B.5 Market entry

Ministerial authorisations

An authorisation from the Minister must be obtained prior to any gas supply activity in Luxembourg. The supplier must fulfil certain conditions, such as guaranteeing that the security and safety of the transportation and distribution networks will not be affected. The granted authorisation to supply gas is not transferable.[32]

Six natural gas suppliers are active on the market with five serving residential customers. Enovos is the dominant player on the residential and professional markets with a market share of respectively 78.3% and 49.5%.

The market for the supply of gas to electricity producers remains largely dominated by Encevo, which holds a market share of 90.4%.[33]

Regarding the oil market, petrol importers must notify the Ministry in charge of energy when intending to import petrol into Luxembourg and provide details of their activities.

Licensing regime

Under Article 4 of the Gas Law 2007, the transmission, distribution and storage of natural gas is subject to the prior authorisation from the Minister. When deciding whether or not to grant such an authorisation, the Minister takes into consideration a number of criteria, including the security and safety of the networks, security of supply of the customers, the maintenance and improvement of the interoperability of the networks, the technical, economic and financial capacities of the operator as well as its capacity to fulfil PSOs. Natural gas suppliers are also subject to licensing requirements.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The Gas Law 2007 imposes different obligations on suppliers in order to ensure the supply of gas to residential clients, either where the contracted supplier is incapable of honouring its obligations or temporarily whilst a client enters into a contract with a supplier (Article 7). It also contains special provisions relating to PSOs by TSOs, DSOs and suppliers[34] and foresees a compensation mechanism to fund extra costs incurred by electricity undertakings due to such obligations.[35]

Smart metering

The Gas Law imposes an obligation on DSOs to implement smart metering for all final customers, with an implementation/equipment rate of at least 90% by 31 December 2021 for electricity. This deadline, originally set for 31 December 2020, was extended by one year following the COVID-19 health crisis. Despite the extension, the target has not been fully met, with an installation rate of 84.8%, which represents however a significant uptick to the installation rate in 2019 (with 68.4%).[36]

B.7 Cross-border interconnectors

Luxembourg is not a gas producer and therefore imports 100% of its gas requirements. Luxembourg has one high pressure gas network that is operated by Creos and is supplied by four entry points: two at the Belgium border (Bras and Pétange); one at the French border (Esch/Alzette); and one at the German border (Remich). The main entry points connecting Luxembourg to the European grid are through the Belgian and German grids.

C. Energy trading

C.1 Electricity trading

Electricity trading in Luxembourg relies largely on bilateral contracts between producers and the historic suppliers (currently, Enovos and Sotel). These contracts are either subject to the regulated regime or freely negotiated.

The contracts with TSOs and DSOs that impose a purchasing obligation in order to promote energy production from cogeneration or renewable sources are subject to the regulated regime. These contracts relate to the electricity produced from non-industrial cogeneration and some of that produced from renewable sources.[37]

The contracts with producers of renewable or cogenerated electricity that are not eligible for the regulated regime (for example, industrial cogeneration from Cegyco (Dupont), Ceduco (Goodyear) and Kronospan) are freely negotiated. DSOs also receive supplies from foreign producers through bilateral contracts.

Most of the suppliers active in Luxembourg procure their electricity on the foreign wholesale markets through bilateral contracts (64% of which for a maximum duration of two years).[38]

There is no energy exchange in Luxembourg. The Creos transmission network is connected to the German grid (Amprion) and, currently, Luxembourg's import capacity is not fully utilised.[39] Consequently, there is no shortage of transport capacity and congestion management is not required. Suppliers in Luxembourg can therefore fully participate in the German wholesale market.

C.2 Gas trading

The Luxembourg gas market is characterised by its total dependence on imports except for biogas. There is no wholesale market in Luxembourg and gas is purchased from foreign markets. The market prices are determined by the prices of adjacent markets (Natural Gas Market ("NCG"), the Dutch transfer facility ("TTF") and ZTP).

Further to the integration of the natural gas market in the BeLux zone a common balancing system has been implemented. For this purpose, Creos and Fluxys have created a joint undertaking named Balansys SA with the mission to act as balancing operator for the balancing in the BeLux zone (see section B.2).[40]

D. Nuclear energy

In the 1970s, plans to build a nuclear power plant in Remerschen, Luxembourg, were abandoned. In the 1980s, a nuclear power plant was constructed in Cattenom, France, about 15km from the Luxembourg border. Nuclear power was then, and remains now, a highly sensitive political issue.

There are currently no nuclear power plants in Luxembourg or plans to commission such a plant. The current government has held a critical attitude to nuclear power in general.[41] On 23 April 2021, the Government, together with Rhineland-Palatinate and Saarland, presented a study on security of supply in the region. The main finding of this study was that the security of supply would be ensured even after the closure of the Cattenom nuclear power plant.[42]

E. Upstream

There are no upstream activities in Luxembourg.

F. Renewable energy

F.1 Renewable energy

Luxembourg is aiming to increase the share of renewable energy from 11% in 2020 to 25% by 2030. Given the size and geography of the country, as well as its population density, this target cannot be achieved within Luxembourg alone. The Government has therefore announced participation in renewable energy projects outside Luxembourg's borders.

The main support instruments for renewable energy remain to be feed-in tariffs and subsidies granted for investment and installation costs for solar heating, heat pumps and household biomass boilers.

F.2 Renewable pre-qualifications

All natural or legal persons are eligible to produce electricity from renewable energy sources (RES) and can claim remuneration through feed-in tariffs, market premiums, and calls for tenders. Contracts must be concluded with an electricity network operator, who is responsible for paying the remuneration. For photovoltaic power plants with a capacity of between 200 and 500kW, only civil or cooperative companies can enter into such contracts.

Contracts in the form of market premiums must also be concluded with a network operator if the power plant has a capacity of at least 500kW, with the exception of wind energy, for which the capacity must be greater than or equal to 3MW or three production units.

With the objective of further supporting the development of solar energy in Luxembourg, the Minister for Energy may initiate competitive tendering procedures in order to identify new solar electricity production facilities that are eligible for the market premium scheme. These tendering procedures may cover facilities on national territory or the territory of a Member State of the EU participating in the competitive tendering procedure.

F.3 Biofuel

The production and processing of Biofuels is regulated in Luxembourg by two Grand Ducal Regulations, which align with EU-wide standards set out, among other things, in the RED (I and II), as well as the Biofuel Directive regarding the specification of petrol, diesel and gas-oil, and introducing a mechanism to monitor and reduce greenhouse gas emissions ("GHG"). Whereas the Grand Ducal Regulation of 27 February 2011 sets the relevant sustainability criteria for (the creation of) biofuels and bioliquids, the Grand Ducal Regulation of 16 March 2012 sets out the relevant minimum requirements for the quality of gasoline and diesel fuels and the sustainable use of biofuels.

G. Climate change and sustainability

G.1 Climate change initiatives

Luxembourg targets a reduction of GHG emissions for the sectors outside the emission trading scheme ("ETS") by 55% by 2030 compared to the base year 2005. Meeting this target will involve further efforts from the government. Whilst giving priority to national reduction measures, the government has announced that flexible measures are also needed to compensate for Luxembourg specific (and mostly territorial) limitations.

In December 2019, the Government published its integrated national energy and climate plan for 2021 – 2030 (“NECP”) based on Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action. The NECP addresses all five dimensions of the EU Energy Union: decarbonisation, energy efficiency, energy security, internal energy markets and research, innovation and competitiveness.

In October 2020, to further contribute to the development of solar power, the Ministry of Energy and Spatial Planning has launched a third call for tenders for photovoltaic power plants for a total volume of 40MW. This is equivalent to the production of green and renewable electricity for about 27,000 residents. In total, projects of about 44MW (14MW in 2018 and 30MW in 2019) were accepted in the first two tenders in 2018 and 2019. The successful bidders can benefit from a market premium contract for the injection of the electricity produced for 15 years.

The Grand Ducal Regulation of 12 April 2019 bolstered the support scheme for the promotion of solar energy. To further support the development of solar energy, the Government announced that the power threshold, above which income from the operation of a photovoltaic installation constitutes taxable income, will be increased.

G.2 Emission trading

Luxembourg did not enact parallel emission trading systems or supplementary regulatory requirements in addition to the EU ETS. The latter covers in Luxembourg the aviation sector as well a total of 20 industrial facilities. Luxembourg has voiced reservations and scepticism as to the EU Commission’s intention to expand the EU ETS to the road transport and building sectors, due to concerns that this may have disproportionate effects for low-income households.[43]

G.3 Carbon pricing

The Law of 23 December 2004, which established the GHG ETS, also provided for the establishment of a special budgetary fund to finance national schemes for the reduction of GHG emissions and to contribute to the Kyoto flexibility mechanisms.

The national registry of GHG emissions has been established through the Grand Ducal Regulation of 1 August 2007, which was replaced on 24 April 2017 by a new Grand Ducal Regulation. The Environment Administration has been designated as the authority in charge.

The management of the financing fund for the Kyoto Mechanisms has been modified through the Law of 22 December 2006, providing, among other things, that the tax on road vehicles (based on the carbon dioxide ("CO_2") emissions of the vehicles) and a special excise duty on fuel ("Kyoto-cent") will be attributed to this fund. Given the volume of transport fuel sales to customers outside Luxembourg and the status of Luxembourg as a transit country and the attraction of low duties, the Government has announced a gradual increase of the excise duties on fuel.

The Grand Ducal Regulation of 19 December 2020, setting the applicable rates for autonomous excise duties on energy products, introduces an additional autonomous excise duty called the ‘CO_2 tax’ on energy products from fossil energy sources. In line with the Grand Ducal Regulation, natural gas is taxed with €4/MWh, which is fully passed on to consumers. These resources will be allocated to finance measures dedicated to reducing GHG emissions, both at a national and international level.

The Law of 22 December 2006 also authorised the Government to participate in the Community Development Carbon Fund and the BioCarbon Fund of the IBRD, as well as in the Multilateral Carbon Credit Fund of the EBRD.

G.4 Capacity markets

Luxembourg does not provide for a specific national framework for capacity market mechanisms.

H. Energy transition

H.1 Overview

The Energy Efficiency Directive ("EE Directive") as well as the amending Directive on energy efficiency (2018/2002) have been progressively transposed into national legislation by the following four laws:

- Law of 19 June 2015 modifying the modified Law of 1 August 2007 concerning the organisation of the electricity market;[44/45]

- Law of 19 June 2015 modifying the modified Law of 1 August 2007 concerning the organisation of the natural gas market ("Laws of June 2015");[46/47]
- Law of 5 July 2016 amending the Law of 5 August 1993 on the rational use of energy;
- Law of 3 February 2021 modifying the law of 1 August 2007 on the organisation of the electricity market of the electricity market; and
- Law of 3 June 2021 modifying the law of 2007 modifying the law of 1 August 2007 on the organisation of the electricity market of the electricity market.

The laws of June 2015 aimed at implementing the provisions of Article 7 of the EE Directive regarding the energy efficiency obligation schemes. This has been criticised by environmental organisations,[48] however, the Luxembourg Parliament decided to impose energy savings obligations as prescribed under Article 7 of the EE Directive on electricity and natural gas suppliers only.[49] The Law of 3 June 2021 continues to only designate natural gas and electricity suppliers as obligated parties within the meaning of Article 2(14) EE Directive. Administrative penalties can be imposed by the ILR on electricity and natural gas suppliers that do not achieve the annual volume of energy savings required by the legal and regulatory framework.

With the law of 3 February 2021 on the organisation of the electricity market, the Luxembourg legislator integrated the concepts of individual and collective self-consumption as well as citizen energy communities into national legislation.

H.2 Renewable fuels

Hydrogen

To date, Luxembourg has not implemented legislation dedicated to Hydrogen fuels. This is expected to change in the near future, with the Luxembourg NECP putting emphasis on the production and reliance on green hydrogen.

Ammonia

To date, Luxembourg has not implemented legislation dedicated to Ammonia fuels.

H.3 Carbon capture and storage

The CCS Directive was implemented through the Law of 27 August 2012 and the Grand Ducal Regulation of 27 August 2012. Luxembourg made use of the option granted under Article 4 of the CCS Directive allowing Member States not to authorise carbon storage on all or part of their territory.

H.4 Oil and gas platform electrification

To date, Luxembourg has not implemented legislation for oil and gas platform electrification.

H.5 Industrial hubs

To date, there are no national industrial hub or territorial cluster projects and no dedicated legislative framework in this respect.

H.6 Smart cities

Although Luxembourg in general and the city of Luxembourg in particular strive for the implementation of smart city concepts from an administrative, environmental and also infrastructure perspective, there is no dedicated legislative framework. Smart metering infrastructure requirements for electricity and gas distributors have been described in sections A.6 and B.6.

I. Environmental, social and governance (ESG)

As European and worldwide financial hub, ESG efforts in the financial sector are most notable for the time being. In 2016, the Luxembourg Stock Exchange launched the Luxembourg Green Exchange ("LGX"), a dedicated platform for sustainable securities and issuers contributing to financing a low-carbon and more inclusive economy. LGX is a meeting place for issuers, asset managers and investors who wish to make their mark on sustainable finance by providing them with an environment for bonds, whether labelled or unlabeled, and funds with clear green, social, sustainable or ESG characteristics. Entry is restricted to issuers and asset managers that provide full disclosure and fulfil their reporting obligations for labelled or unlabeled securities.[50]

A number of different standards, frameworks and taxonomies are included in the LGX eligibility criteria, such as the ICMA's Green Bond Principles ("GBP"), Social Bond Principles (SBP), Sustainability-Linked Bond Principles (SLBP) and other frameworks.

Regarding Green Bonds, the entirety of the net funds raised via the security will be used to finance or refinance green projects, as defined by the GBP and/or the Climate Bonds Initiative's eligibility taxonomy. In 2020, Luxembourg became the first European country to launch a Sustainability Bond Framework which meets the International Capital Markets Association (ICMA) Green, Social and Sustainability Bonds principles. Moreover, the eligibility criteria are fully compliant with the Taxonomy of the EU as well as the European Green Bonds Standard. This Sustainability Bond framework enables the issuance of green, social or sustainability bonds contributing to Luxembourg's sustainability strategies.

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Energy law in Malta

Recent market developments in the Maltese energy sector

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Projects for further progress in the energy sector

With the upgrade of energy infrastructure in Malta, the introduction of new inaugurals came about, amongst which relate to transport, buildings, industry, waste, water and the use of land and agriculture.

Malta's Low Carbon Development Strategy ("LCDS") has been further updated and published in June 2021 and provides a clear overview of the incentives Malta will introduce and that will enter into force before 2050.[1] The LCDS was the outcome of a process which was to last three years, however due to the unexpected Covid-19 pandemic, some of these projects were delayed.

The Energy and Water Agency[2] ("EWA") has made substantial progress in relation to the Malta-Italy gas pipeline interconnection project and plans have been proposed for a second interconnector to be installed. This second interconnector is expected to function in parallel with the firstly installed interconnector channelling Malta with Ragusa, Sicily, and is expected to be finished by 2025. By virtue of this second interconnector, a reduction in greenhouse gas ("GHG") emissions is expected.

Apart from the above, the installation of Solar photovoltaics ("PVs"), solar water heaters and heat pump water heaters further contribute to the reduction of GHG emissions.

These initiatives increase Malta's reliance on thermal energy and also reduce the costs of renewable energy technologies in the future.[3]

Transport emissions

Electric vehicles (EV) incentives

Air pollution has been one of the key topics concerning the matter of climate change, with 33% of carbon emissions in Malta being generated from road pollution.

A new national policy for EV charging infrastructure will open the market by allowing the involvement of the private sector. It aims at regularising the sector and allowing private investors to register as Charging Point Operators with the Regulator for Energy and Water Services ("REWS"). The national policy is in line with Directive 94/2014/EU whereby all member states are to ensure that recharging points are strategically located to provide adequate geographic coverage. This will be determined through a zoning exercise whereby each zone will be assigned a percentage range on public land based on the density of the population in the area and the number of registered vehicles, excluding commercial vehicles.[4]

The Government of Malta ("Government") also offers a scrapping fee of €12,000 to any person who scraps their old car in favour of an EV.

Other incentives already in force include EVs being excluded from the Controlled Vehicular Access payment to enter the capital city of Valletta.

Government transport

To lead by example, the Government intends to electrify its fleet of cars, therefore replacing about 1,800 internal combustion engine ("ICE") vehicles. This would include the installation of a number of charging points at respective government departments.[5]

Public transport

The Government has introduced the concept of electric buses and aims on switching 350 ICE buses into electric fleets.[6] The Government envisages that with the change to electric public transport, public transportation would become free. As of January 2022, public transport has been free for citizens 70 years and over.[7]

Active means of transport

Statistics indicate that cleaner means of travel like bicycle or e-bike will increase if the necessary infrastructure is provided. Such infrastructure includes bicycle lanes, bike parking spaces, charging points for e-bikes, e-scooters, more footpaths and pedestrian areas. Some villages around Malta have already followed up this incentive by limiting some areas for pedestrians. This adds to the promotion of active transport by both decreasing traffic and air pollution and increasing the use of active type of travel.[8]

Working remotely

Due to the Covid-19 pandemic that forced many institutions to operate remotely, it is estimated that about 33% of the local workforce worked remotely.[9] Also, many offices have continued working remotely for time efficiency and it avoids the daily struggle of traffic and parking. Seeing that remote working helped congestion levels and decreased the number of cars on the roads, the Government has promoted this system by providing more governmental online services and e-forms.[10]

Electrification of cruise ships berths

In March 2021, an Italian company called 'Nidec ASI' signed a contract of €12 million[11] in collaboration with a Maltese registered company 'Excel Sis Enerji Uretim Limited' with the aim to pursue and bring to life the 'shore-to-ship' project in Valletta's Grand Harbour. This project is called the 'Grand Harbour Clean Air Project' and consists of the connection of cruise ships anchored in the Grand Harbour to Malta's energy grid. This project contributes towards meeting the obligations indicated in the Directive on Alternative Fuels which are a priority for each member state to implement by 31 December 2025. In this manner, cruise ships would not require the use of diesel generators whilst berthed in the Grand Harbour. The project is expected to have two phases, the first phase requiring a €37 million investment to provide shore power to the five main cruise ship quays of the Grand Harbour[12]. This first phase is to be completed by the end of 2023. This initiative will not decrease sea pollution levels and air pollution by more than 40 tonnes a year[13] and also encourage tourism, the key source of income in Malta.

Renewable energy plan

Malta had committed to reach a 10% target share of energy from renewable energy sources ("RES") by 2020 and has now committed to reach a target of 11.5% in Malta's gross final energy consumption by 2030. Renewable electricity generation reached around 8% of the total by 2019, falling short of the desired target. In order to reach the 10% target, in 2020 Malta purchased renewable energy credits from Estonia costing €2 million.[14]

PV systems and feed-in tariff (FiT) scheme

According to the National Statistics Office, in 2020, Malta's renewable energy from grid-connected PV systems increased by 20.5% from 2019 to 2020 and was estimated at 233.1GW-h.[15] About 29,000 Solar PV's[16] were recorded to be installed, with 85% of them being in Malta and the rest in Gozo and Comino. The total stock of PV installations in the domestic sector is 93.6%, whereas commercial and public sectors accounted for 5.5% and 0.9% respectively.

In relation to the FiT Scheme, the maximum units which were allocated for FiT payment to PV systems approved under this scheme between 1 January 2021 and the 31 December 2021 was 12.8GWh per annum (8MWp).[17]

Solar water heating Scheme

The Government has extended the grant for every purchase made on solar water heaters to encourage the use of renewable energy in residential houses.[18] The percentage covered by the grant reached a maximum of 75% on all costs of the installation of solar water heaters, capped to €1,400 including VAT, whereas an additional grant is provided after 5 years of installation to cover all other costs agreed upon with the supplier.[19]

Heat pump water scheme

A grant on heat pump water heaters was initiated to encourage the use of RES. This scheme is funded through national funds and applies to private individuals who wish to make use of such instalment in their residential properties for domestic purposes. The grant percentage is 50% of the costs of the heat pump water heater itself including VAT and is capped at €1,000.[20]

Waste

The Waste Management Plan for Malta 2021-2030 provides a number of measures to further improve the waste handling system in Malta. These include bio waste that is generated in households, bulky industrial waste and lastly the disposal of items that are easily recycled.[21]

A project which is currently on-going is called ECOHIVE.[22] This is a waste to energy plant which is expected to convert organic waste into clean energy to be used for agricultural purposes, and also act as a replacement of the clinical waste incinerator.[23] This project will feature four different types of waste plant disposals in the Maghtab complex, and the building is expected to cost between €160 and €190 million. An additional €200 million has been budgeted for the commissioning and running of the plant for a period of 20 years.[24] It is expected that the plant would begin operating by the end of 2023.

Another project relating to waste is known as the '9 million Euro European funds' project for the Sant Antnin Plant that will provide farmers with a more sustainable method for the disposal of farm waste leading to an increase in the production of quality water as explained in another project known as the 'New Water' project which is explained below. Using this scheme, farmers will be able to dispose of farm waste at this plant which will reduce the use of urban sewage treatment plants. Apart from creating a cleaner method of waste disposal, it is also safeguarding the marine environment by limiting the amount of waste water ending up in the sea. Therefore, new water is generated and recycled to be used for agricultural needs and this would in turn decrease the consumption of table/ground water.[25]

Water

In accordance with the EU's Water Framework Directive[26] ("WFD"), Malta is to prepare its third River Basin Management Plan ("third RBMP") by March 2022. The preparation for the implementation of the third RBMP requires consultation exercises which have been on-going as well as identifying significant water management issues.[27]

The implementation of the second River Basin Management Plan ("second RBMP") includes a programme of measures which have been developed to address Malta's significant water management measures and provides a framework for implementation in order to ensure the achievement of the WFD's environmental objectives for the water sector by 2021. Malta's second RBMP includes plans for extreme events such as the 'Drought Risk Management Plan' and the 'Flood Risk Management Plan'.[28]

Also, a newly introduced project known as the 'New Water' project aims at producing 7 million m^3 of high-quality water to be used for agricultural purposes and aims at achieving a large amount of good quality and safe groundwater bodies in the Maltese Islands by 2021.[29]

In relation to the agricultural sector, Malta's objective is to create a sustainable water system and to educate farmers on newer and improved ways of water use and conservation by promoting and properly financing the use of smart irrigation systems.

Clean energy for the EU

As stated in the LCDS, Malta's aim is to move towards carbon neutrality by 2050 by following its contribution towards the EU's goals as specified in the 2015 Paris Climate Agreement and the 2020 European Green Deal. Carbon neutrality is necessary for a healthier livelihood and the European Commission aims to reduce net GHG emissions by at least 55% by 2030.[30] The European Green Deal is also regarded as Europe's lifeline out of the COVID-19 pandemic. Through the LCDS, Malta is striving to achieve these goals in various ways notwithstanding its size limitations and lack of resources.

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Overview of the legal and regulatory framework in Malta

A. Electricity

A.1 Industry structure

Nature of the market

The connection of the electricity system to the European grid is of significant importance for Malta. The 100km 200MW HVAC 220kv underwater electricity interconnector completed in 2015, and partly financed by the European Union ("EU"), links Malta to the European energy grid via Sicily. This interconnector has enabled Enemalta plc ("Enemalta") to broaden its energy mix, making it less vulnerable to fluctuations in oil prices. The Marsa power plant was disconnected from the grid in 2017, while the Delimara I plant was switched off on 24 April 2017, marking it as the last day in which Malta used heavy fuel oil for the generation of electricity. This was in line with Enemalta's plan to revamp Malta's electricity generation sector by bringing to an end the use of less-efficient, oil-fired generators and shifting to cleaner technologies. In September 2018, the 50-storey power station chimney of the old Delimara power station, together with the last remaining heavy fuel oil boilers to the chimney, were officially demolished.

Malta does not possess a transmission system nor are there any transmission system operators ("TSOs"). To date, no requests have been made to the Regulator for Energy and Water Services ("REWS") for the designation or certification of TSOs or owners. Consequently, the electricity distribution system supplying all of Malta is the responsibility of one distribution system operator ("DSO") that is part of Enemalta.

Key market players

The key market players in the electrical industry are the Malta Resources Authority ("MRA"), REWS, the Ministry for Resources and Rural Affairs ("MRRA"), the Ministry for Sustainable Development, the Environment and Climate Change ("MSDEC"), the Environment & Resources Authority ("ERA"), the Energy and Water Agency ("EWA") which supports the Office of the Prime Minister ("OPM") which is responsible for energy and water, and the private company Enemalta.

Enemalta is involved in the generation, purchase, transmission, distribution and supply of electrical energy. It is also involved in the importation, purchase, manufacture, bottling, storage, distribution and sale of petroleum, the delivery of energy services, energy efficiency improvement programmes and other energy efficiency improvement measures, together with the promotion of efficiency in the use of energy. Moreover, it is responsible for dispatching generation plants and for balancing the distribution system.

Notwithstanding the liberalisation of electricity generation in Malta in 2007, Enemalta is designated under the Electricity Market Regulations 2011 as amended ("EMR") as the only DSO in Malta. Enemalta is responsible for operating, maintaining and developing a secure, reliable and efficient electricity distribution system to guarantee a constant electricity supply in Malta with due regard to the environment and energy efficiency. Enemalta must give priority to generating installations that utilise renewable energy sources ("RES"), waste or cogeneration.

Enemalta may only enter into contracts for the procurement of goods, services or materials in accordance with the Public Procurement of Entities operating in Water, Energy, Transport and Postal Services Sector Regulations.[1] The Chamber of Small and Medium Enterprises ("GRTU") has published proposals to open up the possibility for the private sector to set-up micro generation plant independent from Enemalta to increase competition in the energy distribution network and to reduce energy prices.

Regulatory authorities

Established through the Regulator for Energy and Water Services Act[2] ("REWS Act") regulates, REWS monitors and reviews all practices, operations and activities relating to energy and water services and resources. Moreover, the REWS grants licences or permits for the carrying out of any operation or activity relating to these services and is empowered to secure interconnectivity for the production and distribution of such services. The REWS Act regulates the national utilities and service providers for energy and water, namely Enemalta and the Water Services Corporation and their subsidiary companies, together with retailers and operators in the regulated sectors, such as suppliers and delivery operators of gas and kerosene, operators of fuel stations, private operators of desalination plants, operators of road tankers and tradesmen and service providers, including electricians.

The following operations and activities require a licence issued by the REWS under the EMR:[3]

- the generation of electricity;
- the supply of electricity; and
- the functions of a DSO.

Authorisation from the REWS is also required for the construction of a power station. Licences are granted or refused by the REWS on the basis of established criteria, including compliance with planning permits, adherence to health and safety requirements, environment protection, the applicant's private and professional integrity and compliance track-record. The REWS also has the power to suspend, revoke or cancel any such licence on regulatory grounds.

Legal framework

The Maltese legal framework for the electricity sector also includes the Electricity Supply Regulations ("ESR"),[4] the Electricity Transit (Grid Requirements) Regulations,[5] the Promotion of Energy From Renewable Sources Regulations,[6] the Sale of Electricity generated from Cogeneration Units Regulations,[7] the Guarantees of Origin of Electricity from High Efficiency Cogeneration and Electricity, Heating and/or Cooling from Renewable Energy Sources Regulations,[8] and the Feed-in Tariffs Scheme (Electricity Generated from Solar Photovoltaic Installations) Regulations.[9]

Implementation of EU electricity directives

Both the Third Party Directive and the Security of Electricity Supply and Infrastructure Investment Directive have been transposed into national law, in particular the EMR. Malta still enjoys derogations from the requirements linked to the unbundling of transmission systems and TSOs and also the unbundling of DSOs. Additional derogations include those from the requirements of third-party access and market opening, as well as reciprocity.

A.2 Third party access regime

As the DSO, Enemalta is expected to supply any new producer generating electricity from renewable sources with the required information for efficient access to, and use of, the system. The Electricity Market (Amendment) Regulations[10] require the REWS to assure that the tariffs charged by the DSO for the distribution of electricity from plants employing RES reflect reasonable cost benefits resulting from the plant's connection to the network. The REWS is responsible for ensuring that the distribution tariffs do not discriminate against electricity from renewable sources in order to prevent abuse of Enemalta's monopoly.

Enemalta has developed a Network Code ("NC") to regulate third party access to the electricity distribution network. The NC allows safe and controlled access for generators and auto producers who wish to use the network. Access to the system must be granted in a non-discriminatory way to all existing and future generators. All users of the distribution system must comply with the NC, the EMR, the ESR[11] and any other relevant legislation that may be in force from time to time. Users must also enter into technical and other agreements with Enemalta as the DSO.

In the event that the DSO refuses access to the network due to lack of capacity, the REWS may authorise the applicant to construct a direct line (not connected to the distribution system) for the sole purpose of facilitating the supply of electricity for which the application for use of the distribution system was made and refused. The REWS must establish objective and non-discriminatory criteria for the grant of such authorisations. It is also duty-bound, in consultation with other national authorities, to take all reasonable measures to facilitate access to the network for new generation capacity and to remove barriers that could prevent access for new market entrants and for electricity from RES. The Communications, Energy, Transport and Financial Services Markets Directorate of the Malta Competition and Consumer Affairs Authority is responsible for overseeing competition and taking action in respect of infringements and concentrations in the energy market. Presently there is no third party connected to Enemalta's distribution system.

A.3 Market design

There is only one national electricity grid in Malta. Presently, electricity is generated locally and is also imported through the Malta-Italy connector by Enemalta, as Malta's electricity network operator. The generation of electricity is carried out by Enemalta by means of the Delimara III plant, previously known as the BWSC plant, which was converted to gas by Shanghai Electric Power Co. Limited, as well as the new Delimara IV plant which is operated by Electrogas Malta Ltd ("Electrogas"), a joint venture comprising of Siemens, Azerbaijan's SOCAR and a consortium of Maltese investors. The Delimara II plant which uses gas oil has been kept in reserve. The Delimara III plant generates 149MW by means of its internal combustion engines while Delimara IV produces about 180 – 220MW by means of its combined cycle gas turbine plant.

A.4 Tariff regulation

In consideration of the derogation granted to Malta in relation to The Third Electricity Directive, any autonomous power producer joined to the distribution network must sell all the electricity generated but not consumed on site to Enemalta as the exclusive supplier of electricity. The retail tariff that is paid by consumers in exchange for electricity encompasses the costs and revenues related to the operation of the distribution network apart from those linked to electricity importation, generation and supply activities. There are no separate tariffs for the use of the network. The ESR regulates the charges to connect to the network together with methodologies for the determination of such charges. Such regulations are applicable to all users that seek to connect to the network.

The DSO may enter into special agreements to charge prices besides those provided by the aforementioned regulations. Such prices must be less than those established by tariffs. The REWS has the power to authorise any recommended tariffs proposed by the DSO that grant adequate revenue to the DSO within any financial year with regard to the generation, distribution and sale of electricity. Generally, its purpose should be to cover operational, administrative and financial costs and to allow a legitimate return on equity. Besides proposed tariffs, the DSO must convey all necessary documentation requested by the REWS. Similarly, the EMR provides that the function of the REWS is to fix or approve tariffs for the purchase, supply and distribution of electricity.

A.5 Market entry

The electricity retail market is not open to competition. Enemalta remains the only licensed supplier of electricity to end customers, and there is no wholesale market for electricity. As there is only one supplier of electricity, it is not possible to implement customer switching. There are no transmission systems and no TSOs in Malta. The electricity generation market is open to competition and generators may generate electricity for their own consumption and, or to sell to Enemalta.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Enemalta is responsible for ensuring the availability of ancillary services both to generation and distribution of electricity. Similarly, it must develop objective, transparent and non-discriminatory rules for scheduling and criteria for dispatching taking into account contractual obligations which include PSOs. Presently, the only public service relates to street lighting. There are no PSOs applicable to generators, network operators or suppliers regarding electricity.

By incentivising energy efficiency and consumption reduction in order to reach its national energy targets, Malta is to adopt guidelines in the public sector specifically regarding public buildings whereby all façade lighting on public buildings and monuments must be switched off late in the night. Moreover, the Maltese Government ("Government") is set to impose guidelines in relation to air-conditioning temperature limits. All government and public sectors are to set their air conditioning units (ACs) at a minimum of 24 degree Celsius when used for cooling and a maximum of 21 degree Celsius when used for heating. There is an exception to these limits in relation to hospitals and health care centres.[12]

Smart metering

Enemalta's Automated Meter Management project for the removal of old electricity meters and subsequent installation of smart meters is almost complete at 98.5%.

Electric vehicles

Transport Malta launched five grants for motorists and aim to more financial incentives to Maltese families in order to make use of more sustainable and efficient means of transport. Under the first grant, a person can benefit from a grant of €800 when a heavy-duty motor vehicle is equipped with this system, resulting in a reduction in smoke emissions of at least 25%. Under the second grant, persons who purchase environmentally friendly M1 vehicles are eligible for a grant of €1,500 while persons who purchase hybrid vehicles in category M1 are to be awarded €2,000. Under the third grant, persons, NGOs, businesses and private companies who scrap old vehicles and purchase an electric vehicle or a hybrid vehicle may benefit from a grant ranging between €1,000 to €9,000. Under the fourth grant, a person registering a pedelec or a new category L vehicle is eligible for a grant of €1,000 when removing from registration a vehicle in Category M1 or N1 which is at least ten years old, whilst a €500 grant will be awarded to anyone registering a pedelec or a new category L vehicle after removing from registration a Category L vehicle which is at least ten years old. Finally, under the fifth grant a person can benefit from a grant amounting to €10,000 when they register a new vehicle in category M1, or M2 or M3.

A.7 Cross-border interconnectors

The sub-sea interconnector has been in operation since 2015, linking Malta to the European grid via Sicily, with a capacity of 200MW. This interconnector may be used to import and export electricity so as to enable operation at peak efficiencies. The REWS supervised the implementation of the Sicily-Malta electricity interconnector in accordance with the EMR. The Maltese and Italian electricity systems were synchronised for the first time in March 2016 and programmed electricity imports through the interconnector commenced in April 2016.

Unfortunately, some damage was caused to an interconnector cable during a March storm by a tanker which dragged its anchor off Bahar ic-Caghaq. Enemalta has estimated a cost of €49 million to repair the damaged cable. Enemalta is currently involved in a legal battle to recoup these costs. The interconnector requires repairs which are to be undertaken later in 2022 in order to be fully functional.[13]

Due to high demand for electricity, which has climbed by 18% over the past four years and is estimated to continue increasing, Malta is set to install another electricity interconnector which also aims to link Malta with the island of Sicily. This interconnector will run parallel with the already existing interconnector which links Malta with Ragusa. The 200MW cable is expected to cost €170 million and is expected to be completed in 2025.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Oil exploration and exploitation rights in relation to offshore natural resources rest exclusively with the Government. All other activities related to energy resources such as granting of authorisation for the transportation and storage of oil are the responsibility of the REWS. However, there is currently no production of oil in Malta and therefore, there is no market for trading this resource.

Gas

Nature of the market

To date, Malta is completely reliant on third country imports of liquefied petroleum gas ("LPG"). The main importer of petroleum products in Malta is Enemalta. Easy Gas Ltd is also involved in the importation and distribution of LPG in Malta. The yearly importation of petroleum products for local use amounts to about 1.25 million tonnes of which 60% is fuel oil used by Enemalta for electricity generation, 20% is gas oil and diesel (automotive gasoil) and the remainder is Jet A1 and gasoline. Fuel consumption in the aviation industry accounts for 10% of Enemalta's petroleum sales. Enemalta further provides storage of petroleum for international oil companies at its 'Has-Saptan' underground installation which has a capacity of 150,000 tonnes.

Key market players

The key market players are the same as those for the electricity market.

Regulatory authorities

The REWS is the national regulatory authority, which is the same as that for the electricity market.

Legal framework

In accordance with the Natural Gas Market Regulations ("NGMR" or "Regulations"), authorisation by the REWS is necessary for the construction and/or operation of natural gas facilities, pipelines and associated equipment and also for the supply of natural gas. The REWS must publish objective and non-discriminatory criteria for undertakings applying for authorisation and also to consider the importance of proposed projects for the internal market in natural gas.

The management and operation of Enemalta's LPG activities has been transferred to Gasco Energy Ltd ("Gasco") following a concession by Enemalta, while distribution has been taken over by Liquigas Malta Ltd ("Liquigas"). The storage of LPG is regulated by the Liquefied Petroleum Gas Market Regulations.

Implementation of EU gas directives

The NGMR, which transpose the Third Gas Directive, regulate the distribution, supply and storage of natural gas, including liquefied natural gas ("LNG"), biogas and gas from biomass. The key market players and the national regulatory authority are the same as those for the electricity market.

B.2 Third party access regime to gas transportation networks

Malta does not have any gas transmission networks, and has therefore obtained a derogation under the Third Gas Directive from the requirements linked to the unbundling of transmission systems and TSOs. The NGMR require DSOs not to discriminate between system users or classes of system users. The Regulations require each DSO to provide any other DSO, LNG system operator, and/or storage system operator with sufficient information to ensure that the transport and storage of natural gas takes place in a manner compatible with the secure and efficient operation of the interconnected system. The Regulations also require the REWS to approve the tariffs for third party access to the distribution system and LNG facilities. The same objectives and non-discriminatory tariffs are applicable to all eligible customers including supply undertakings. The REWS may in order to ensure transparency and non-discrimination, choose between: (i) negotiated access or (ii) regulated access in order to organise access to storage facilities and line pack, when technically and/or economically necessary for providing efficient access to the system for the supply to customers.

The REWS may also require any DSO to publish an objective and non-discriminatory NC, subject to the REWS' approval. This NC may establish the basic technical design and operational requirements for the connection to the distribution system of LNG facilities, storage facilities, distribution systems and direct lines. Any such NC is subject to notification in terms of the Notification Procedure Regulations. Natural gas undertakings may refuse access to the system on the basis of lack of capacity having regard to the criteria and procedures set out in the Regulations.

Under the NGMR, new major gas infrastructure such as interconnectors and LNG facilities may be exempted by the REWS for a defined period of time from the requirement to provide third parties with access to the distribution system or storage facilities. This is subject to the satisfaction of certain conditions, including that the exemption is not detrimental to competition, to the effective functioning of the internal natural gas market, or to the efficient functioning of the regulated system to which the infrastructure is connected. The REWS must transmit a copy of every request for exemption and of any decision taken in that regard to the European Commission ("Commission").

B.3 LNG terminals and storage facilities

In October 2016, the LNG storage tanker, Armada LNG Mediterrana, arrived in Malta from Singapore in order to store and provide LNG to the new 400MW Delimara IV power plant. The tanker has a gross tonnage of around 125,000 tonnes and has been converted to a floating storage unit.

The NGMR requires natural gas undertakings which own storage or LNG facilities to designate one or more storage and LNG system operators to operate, maintain and develop secure, reliable and efficient storage and/or LNG facilities to ensure an open market and to meet service obligations. The operator must also refrain from discriminating between system users or classes of system users, particularly in favour of any of its related undertakings.

The system of LNG bunkering is a form of practice where fuel is provided to a ship without releasing a large content of pollutants. Through Directive 2011/33/EU, the EU encouraged member states to control the amount of sulphur which makes up the fuel for marine vessels. Moreover, the Commission is introducing the idea of using alternative substances for fuels through the implementation of Directive 2014/94/EU. This is still a new concept in the Mediterranean. In fact, there are no LNG refuelling facilities on the island, however, by means of a collaboration between the Ministry of Energy and Water Management and Transport Malta, a new research study has been conducted to determine the most feasible method of refuelling, both economically and environmentally, in order to introduce LNG as a Marine Fuel in Maltese ports.

B.4 Tariff regulation

In 2009, Liquigas took over the distribution and marketing of LPG from Enemalta, which remains responsible for storing LPG through its Gas Division. Liquigas lists both its distribution points and prices on its website. Tariffs for the provision of services by the DSO are fixed according to a methodology that is compatible with that found in the NGMR in both a non-discriminatory and cost-effective manner. Any access tariff by third parties to the distribution system and also to LNG facilities must first be approved by the Regulator.

The REWS is responsible for fixing or approving methodologies that are used to determine or provide the terms and conditions regarding the transmission and distribution tariffs, together with tariffs for access to LNG facilities. It ensures that the DSO is incentivised to achieve efficiency, market integration and to guarantee supply, as well as to undertake research activities. Distribution tariffs may not discriminate against gas stemming from RES.

B.5 Market entry

Under the NGMR, a licence from the REWS must carry out the functions of a natural gas undertaking, a storage system operator, an LNG system operator, a DSO and/or to operate a direct line.

The MRRA establishes a licensing requirement for the carrying out of any activity or operation relating to mineral resources. In addition, in the case of the exploration and production of hydrocarbons, the issue of a licence by the MRA is also subject to the Minister's authorisation in terms of the Petroleum (Production) Act ("PPA").[14] Under the Petroleum (Production) Regulations ("PPR"),[15] any company may apply for a petroleum production or exploration licence.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Electrogas has a PSO to make electricity and gas available to Enemalta as well as to supply electrical energy and gas once it is dispatched by Enemalta.

Smart Metering

There are no smart meters in relation to gas in Malta.

B.7 Cross-border interconnectors

There has been progress in relation to the Malta-Sicily 160km gas pipeline whereby three new studies have commenced in order to undertake a marine route survey of the offshore route as well as environmental and engineering design studies. The aim of this connection to the trans-European Natural Gas Network is to be able to import and distribute natural gas from the Italian Gas network for the generation of electricity. The project is in line with the objectives of Malta's 2030 National Energy and Climate Plan ("NECP") and will contribute towards the EU's climate and energy goals. The pipeline had already been given the go-ahead by the ERA, which earlier in 2021, approved an environmental impact assessment ("EIA") report for its construction. The gas pipeline is estimated to cost around €400 million.[16] The gas pipeline will eventually replace the floating LNG storage tanker currently supplying LNG the Delimara IV power plant.

C. Energy trading

C.1 Electricity trading

Following consultation with the appropriate national authorities, the REWS is to take all reasonable measures in order to: (i) eliminate any restrictions relating to the trading of electricity between Member States; and (ii) develop necessary cross-border transmission capacities so as to meet demand while enhancing the integration of national markets to facilitate electricity flows across the European Community. The electricity interconnector between Malta and Sicily, connecting Malta to the European grid has made way for an energy retail market which is expected to remain limited to the Maltese market as there is limited scope for surplus on-island generation and no Euro-Mediterranean electricity ring linking Europe to North Africa.

C.2 Gas trading

Currently, there is no internal natural gas market in Malta, although a market for natural gas is expected to come into existence once the gas pipeline between Malta and Sicily is operational.

D. Nuclear energy

Malta does not generate nuclear energy and the only uses of radioactive materials in Malta are medical and industrial.

E. Upstream

Presently, Malta does not have any upstream oil and gas activities.

The PPA regulates the searching and boring for petroleum which includes all-natural hydrocarbons, liquid or gaseous, including crude oil, natural gas, asphalt, ozokerite and cognate substances, and natural gasoline. This is subject to licensing by the MRA and to Government authorisation. Licensing and authorisation are subject to a number of criteria including:

- the technical and financial capability of an applicant;
- the manner in which an applicant proposes to prospect, explore or bring into production the geographical area which is the subject of the call for applications;
- economic and financial considerations; and
- other terms and conditions including payment of royalties or other considerations as determined by the Minister.

A public call for applications and the grant of a licence is subject to procurement and competition rules under Maltese and EU law.

The PPR provide both for an exploration licence and a production licence. A production licence may also include rights to search for petroleum. An application for a production licence must be in respect of one or more blocks or areas. An applicant for a licence may submit more than one application and may be granted more than one licence.

Every production and exploration licence must incorporate the model clauses set out in the Model Production Sharing Contract (2001) and the Model Exploration Study Agreement (2001) and other terms and conditions as may be specified in the relevant call for applications, or which may be agreed by the Government and the licensee in any particular case.

F. Renewable energy

F.1 Renewable energy

The Government published a Low Carbon Development Strategy in September 2021, setting a strategic direction for the next 30 years, including a set of measures whereby economic growth is decoupled from natural resource use and environmental pressures.

The strategy, in combination with other national strategies and plans, will ensure carbon emissions reductions across the main sectors of the Maltese economy, in line with the EU climate neutrality ambition set by the European Green Deal and the Paris Agreement goals. The strategies include conserving energy and reducing emissions from transport, buildings, industry, waste disposal, water generation, and the sector of agriculture and land-use, land-use change and forestry. This will decrease the demand for energy generation and unsustainable resources, while also resulting in a reduction in carbon emissions. It aims at promoting green investment over 30 years, while improving the quality of Malta's building stock, mobility patterns, health and lifestyle.

Malta is already subject to greenhouse gas ("GHG") mitigation commitments under the EU climate action regulation. Under this set of regulations, the EU has set efforts to reduce its overall 1990 emission levels to 55% by 2030 and be climate neutral by 2050.

Malta's commitment to achieve the decarbonisation of its transport sector is evidenced by its transport strategy launched in 2017, namely the 'Transport Master Plan 2025'. This strategy aims at achieving the goals that are set out in the National Transport Strategy 2050. Articles 3(2), 4 to 14 and 21(2) of the Renewable Energy Directive were transposed into Maltese law by virtue of the Promotion of Energy from Renewable Sources Regulations.[17] Article 15 of the Directive was transposed by the Guarantees of Origin of Electricity from High Efficiency Cogeneration and Electricity, Heating and, or Cooling From Renewable Energy Sources Regulations[18] and Article 16 of the Renewable Energy Directive has transposed by the EMR.

The Feed-in Tariffs Scheme (Electricity Generated from Solar Photovoltaic Installations) Regulations 2013[19] which was amended in 2022, replaces the previous regulations and feed-in tariff rates. Consequently, installation operators which, prior to the entry into force of the Regulations, were subject to a net metering arrangement, were able to: (i) either retain the existing net metering arrangements (with Enemalta and be paid the spill off tariff for electricity generated; or (ii) sell/export the excess electricity generated by photovoltaic ("PV") installations to the distribution system. With regards to solar PV installations commissioned after the entry into force of the Regulations, the installation operator is only able to sell/export the excess electricity generated by the PV installations to the distribution system.

The feed-in tariffs payable under the current scheme by Enemalta to installation operators for electricity generated from solar PVs installed in Malta and Gozo differ for roof mounted and ground mounted installations, domestic and non-domestic installations and also depend on whether the installation's capacity is less or greater than 1000kWp.

Article 13 of the Feed-in Tariffs Scheme Regulations 2013 establishes that installation operators which opt to generate electricity from solar PVs are subject to a paid feed-in tariff or to which the net metering arrangement with a spill-off tariff applies, shall not be entitled to any tradable green certificates for electricity generated.

The harvesting of renewable energy from PVs in 2021 resulted in an 8% increase from the previous year according to the National Statistics Office. When calculating energy production, there was an increase of 9% over 2020 and 2021 with panels used for commercial buildings to result to 52% of the total kWp. EU Regulation 2018/1999 on the Governance of the Energy Union and Climate Action ("EUCA Regulation") was adopted in 2018 and establishes the legislative foundation, governance mechanism, strategies and measures designed to meet the targets of the energy union and the long-term EU GHG emission commitments. In line with the EUCA Regulation and with the aim of meeting the EU's energy and climate target to cut GHG emission levels by 2030, Malta, like every EU Member State, established a ten-year integrated NECP for the period of 2021 to 2030.

One of the biggest headlines on the renewable energy front was the European Green Deal. This initiative reaffirms the EU's ambition in relation to climate change and renewable energy targets. It aims at boosting the efficient use of resources and moving to a clean, circular economy, while also restoring biodiversity and making Europe carbon neutral by 2050. The online platform, 'Green Deal Malta', will facilitate the implementation of Green Deal projects in Malta.

F.2 Renewable pre-qualifications

There are no renewable pre-qualifications.

F.3 Biofuel

The Biofuels Directive[20] was transposed into Maltese law by the Quality of Fuels Regulations[21] and by the Biofuels, Bioliquids and Biomass Fuels (Sustainability Criteria) Regulations.[22] Directive 2009/119/EC[23] imposes an obligation on Member states to maintain minimum stocks of crude oil and, or petroleum products. This Directive was transposed into Maltese law by the Maintenance of Minimum Stocks of Crude Oil and the Petroleum Products Regulations 2013.[24] This Regulation requires economic operators to carry out the necessary measures to ensure that the total oil stocks maintained correspond to an average of at least 90 days of daily net imports or an average of 61 days of inland consumption (whichever is greater) at all times.

To promote the use of biofuels, the Biofuels Regulations 2010 impose a biofuel substitution obligation on importers/ wholesalers of fuel for the transport sector, requiring them to place an increasing share of sustainable biofuel on the market. An authorised provider carrying out the activities of an importer and/or wholesaler of petroleum must ensure that the minimum quantity of biofuel as a percentage of the total energy content placed on the market is audited and verified to comply with this biofuel substitution obligation.

G. Climate change and sustainability

G.1 Climate change initiatives

The Climate Change Package has been largely implemented into Maltese law. Malta was one of the first Member States to complete its national procedures of ratifiying of the Paris Agreement on Climate Change of December 2015.[25] As a party to the Agreement, Malta must prepare a plan to tackle GHG emissions every five years.

The Climate Action Act,[26] which was enacted in 2015, binds the Government to achieve targets to decrease emissions within the context of the EU Energy and Climate Packages and to ensure the regular update of mitigation and adaptation policies and their proper implementation. The Act also provides for a climate fund. The enactment of this law coincided with the United Nation's effort to bring climate change back to the international agenda. At a national level, this law has strengthened Malta's National Mitigation and Adaptation Strategies and Obligations. It also provides a framework for the implementation of a National Low Carbon Development Strategy to meet the requirements of Malta's EU obligations and the United Nations Framework Convention on Climate Change.

At the Commonwealth Heads of Government meeting held in Malta in November 2015, the Heads of Government of the Commonwealth Member States adopted a Statement on Climate Action underlining their commitment to work together and with all other Parties to achieve a low-emission climate future as an outcome of the 2015 Paris Climate Conference (COP21).[27]

In November 2016, the EWA launched the revision of Malta's Renewable Energy Action Plan for the purpose of public consultation. This followed the Commission's approval of Malta's plans, proposing power generation from RES and financial aid for operators of both solar and wind energy installations in Malta. These proposals intend that Malta curtails its reliance on fossil fuels and as a result, improves its air quality while encouraging investment in green energy. As an EU Member State, Malta had been tasked with producing at least 10% of its energy from RES by 2020, in keeping with the EU's renewable energy targets set out in the Renewable Energy Directive on the promotion of the use of energy from renewable sources. This Directive requires Malta to publish a National Renewable Energy Action Plan ("NREAP") to demonstrate how Malta intends to achieve its renewable energy targets. The first NREAP was submitted in 2010 and was further updated in 2016; the plan is more focused on solar energy rather than wind energy due to the lack of feasibility of the wind farm projects as well as environmental concerns. This Directive has since been amended by Directive EU2015/1513, also known as the

'Amended Fuel and ERS Directive', which was transposed into Maltese law through Legal Notice 410 of 2017.[28]

In 2021, the Government launched six new grant schemes to incentivise the production storage and the better use of the renewable energy generated in Malta. These schemes will be administered by the REWS. The aid for solar energy will accommodate households with already existing systems to utilise battery powered systems and help new households' install new solar panel systems. The schemes will also cover households with existing solar panel systems in Malta which have expired feed-in-tariffs. In fact, tariffs that have expired after six and eight years shall be extended by 14 and 12 years respectively.

Three schemes in respect to new solar water heaters and heat pumps were also launched in 2021 by the Minister for Energy, Enterprise and Sustainable Development which are set to encourage more families to invest in renewable energy and to reduce their energy bills. The schemes focus on two technologies, mainly the solar water heaters and air-to-water heat pumps to cater for those households which do not have roof access. Through such schemes, consumers will be able to switch from the conventional geyser to more efficient water heaters, thereby saving on electricity as well as allowing households to heat water in an efficient and environmentally sustainable way.

G.2 Emission trading

The Government has set up an inter-ministerial committee in order to draft the NECP for 2021-2030 which will outline how Malta intends to achieve the national binding target of -19% of GHG emission reduction in 2030 in relation to 2005 levels, including Malta's national contribution towards EU targets for the year 2030 in relation to renewable energy and energy efficiency.

The ETS Directive 2003/87/EC was fully transposed into Maltese law by Legal Notice 140 of 2005. The New EU ETS Directive was also transposed into Maltese law as Subsidiary Legislation 423.50 entitled 'European Union Greenhouse Gas Emissions Trading Scheme for Stationary Installations Regulations'[29] as well as the Subsidiary Legislation 423.51 entitled 'European Union Greenhouse Gas Emissions Trading Scheme for Aviation Regulations'.[30] The EU Greenhouse Gas Emissions Trading Scheme for Aviation Regulations 2012 provides for the implementation of the EU scheme for GHG emissions allowance trading in respect of certain aviation activities carried out by aircraft operators licensed by the Maltese Civil Aviation Directorate.

Malta is one of nine Member States that have signed a ministerial letter calling upon the EU to deliver urgent reforms to the EU's ETS in order to bring to an end the long-standing surplus of emissions allowances within the market. This joint ministerial letter called for the introduction of a new Market Stability Reserve in 2017. The reform of the ETS was approved by the Council in 2018 and the 'Revised EU ETS Directive' 2018/410 aims at a reduction of GHG by 40% by 2030. To date, this directive has not been transposed into Maltese Law.

G.3 Carbon pricing

Malta has witnessed a reduction in carbon emissions, however, in order to drastically reduce emission levels, further efforts are required. In a post-Covid scenario, both consumption and energy demands are progressing. Therefore, implementing behavioural changes towards more climate friendly and sustainable practices is essential in driving Malta towards a carbon-neutral island. Campaigns such as ClimateOn, Seedgreen, Ecobuild and Saving our Blue have already paved the way for such change.

Following the publication in 2021 of the Low Carbon Development Vision, the Government has committed to becoming carbon neutral by 2050. This strategy addresses Malta's decarbonisation journey by prioritising the most cost-effective measures to improve energy efficiency and promoting RES while also taking into account their socio-economic impacts. This is in line with the EU Regulation on the governance of the energy union and climate action (EU/2018/1999) and the Low Carbon Development Vision which was published in 2017.

G.4 Capacity markets

There are no capacity markets.

H. Energy transition

H.1 Overview

In 2021, Malta secured a derogation agreed upon by EU Ministers which ensures that an eventual hydrogen-ready undersea gas pipeline will be eligible for EU funding. Under this derogation, it has been agreed that the project will be recognised as a Project of Common Interest by the EU, therefore permitting the Government to apply for funding under revised Trans-European Transport Network regulations.

H.2 Renewable fuels

Hydrogen

It is being proposed that a 151km long submarine pipeline will connect Delimara to Gela in Sicily which will then connect Malta to the European hydrogen supply grid. By introducing the hydrogen pipeline, the 'floating storage and regasification unit' that has been anchored in Delimara since 2017 would no longer be required.

Ammonia

There is no knowledge of ammonia being used as a renewable fuel in Malta.

H.3 Carbon capture and storage

The Geological Storage of Carbon Dioxide Regulations transpose the Carbon Capture and Geological Storage ("CCS") Directive.[31] According to the Waste Regulations,[32] any facility carrying out waste management operations must obtain a permit from the ERA. The Waste Regulations require the ERA to establish waste prevention programs. In July 2013, the MSDEC launched a preliminary consultation process for the formulation of a 2014-2020 Waste Management Plan and a consultation document was published in October 2013 to address the gaps identified in the previous plan for upgrading the waste management sector. The Waste Regulations allow the ERA to deviate from their provisions in the event that the ERA deems this to be necessary to manage waste without undue delay to minimise potential threats to the environment. The Industrial Emissions (Waste Incineration) Regulations 2013[33] regulate the emission of waste gases from waste incineration plants and waste co-incineration plants which co-incinerate solid or liquid waste.

Apart from the six carbon capture/storage facilities in Malta, a number of private companies operate waste management facilitates on a smaller scale. The Government has continued to implement its Waste Management Plan 2021- 2030 whereby it aims to facilitate the prevention of waste and the reuse of materials by industry, Government, citizens and tourists.

H.4 Oil and gas platform electrification

The main electrification project relates to cruise liner electrification. This Grand Harbour Clean Air Project aims to improve the air quality of the Maltese Grand Harbour. This project will cut over 90% of air pollution produced by cruise liners and ro-ro vessels. This will allow ships to switch off their gas or heavy oil engines once berthed at the Grand Harbor. Electricity will then be distributed to the cruise liner from an existing Enemalta primary substation in Marsa, to the Grand Harbor's cruise liner quays in Floriana, Marsa and Senglea. The connections will reach the five main quays that cruise liners use when visiting Malta. The second phase of the project will extend short-side electricity to Laboratory Wharf and Fuel Wharf in Paola where Infrastructure Malta will be building a new cargo handling facility in the coming years.

According to preliminary research, Malta is estimated to save up to €375 million in costs linked to air pollution's impact on health, the environment, infrastructure and agriculture within the next 20 years. Moreover, this project will also reduce the impact of cruise liner noise and engine vibrations in the Grand Harbour area.

Currently, Infrastructure Malta has laid over 8km of the cables required to make Malta's principal port one of the first in Europe to introduce shore power for cruise liners and ro-ro vessels. Infrastructure Malta is planning to complete the first phase of the Grand Harbour Clean Air Project by 2023.

H.5 Industrial hubs

There are currently no industrial hubs in Malta.

H.6 Smart cities

There are currently no Smart Cities in Malta.

I. Environmental, social and governance (ESG)

In a study conducted by the Central Bank of Malta in their Quarterly Review of 2021, it was stated that Malta had committed to reach a target share of energy from RES of 10% by 2020 and 11.5% by 2030 in Malta's gross final consumption of energy. By 2019, it was reported that renewable energy production had reached around 8% of the total. Due to its size, Malta faces many difficulties in implementing new energy incentives and thus relies on foreign sources. As a recovery and resilience plan to mitigate this issue, the Government is set to invest €189 million which will go towards environmental related initiatives.[34]

Endnotes

1. Subsidiary Legislation 601.05 of the laws of Malta.
2. Chapter 545 of the laws of Malta.
3. Subsidiary Legislation 545.34 of the laws of Malta.
4. Subsidiary Legislation 545.01 of the laws of Malta.
5. Subsidiary Legislation 545.10 of the laws of Malta.
6. Subsidiary Legislation 545.35 of the laws of Malta.
7. Subsidiary Legislation 545.29 of the laws of Malta.
8. Subsidiary Legislation 545.36 of the laws of Malta.
9. Subsidiary Legislation 545.27 of the laws of Malta.
10. Legal Notice 37 of 2017.
11. Subsidiary Legislation 423.01 of the laws of Malta.
12. Times of Malta, "Air conditioning limits introduced for public sector as energy costs climb', published 28 August 2022.
13. Times of Malta, dated 19 July 2022, 'Cost of interconnector cable damage estimated at €49m', available at www.timesofmalta.com/articles/view/cost-interconnector-cable-damage-estimated-49m.969085.
14. Chapter 156 of the laws of Malta.
15. Subsidiary Legislation 156.01 of the laws of Malta.
16. Times of Malta, dated 21 October 2021, 'Malta-Sicily gas pipeline gets a planning permit', available at www.timesofmalta.com/articles/view/malta-sicily-gas-pipeline-gets-a-planning-permit.907000.
17. Subsidiary Legislation 545.35 of the laws of Malta.
18. Subsidiary Legislation 545.36 of the laws of Malta.
19. Subsidiary Legislation 545.27 of the laws of Malta.
20. Directive 2003/30/EC of the European Parliament and of the Council of 8 May 2003 on the promotion of the use of biofuels or other renewable fuels for transport.
21. Subsidiary Legislation 545.18 of the laws of Malta.
22. Subsidiary Legislation 545.37 of the laws of Malta.
23. Council Directive 2009/119/EC of 14 September 2009 imposing an obligation on Member States to maintain minimum stocks of crude oil and/or petroleum products.
24. Subsidiary Legislation 545.09 of the laws of Malta.
25. 'Instrument of Ratification declaring that the Government of Malta has Ratified the Paris Agreement on Climate Change of December 2015 deposited', Ministry of Foreign Affairs, 5 October 2016.
26. Chapter 543 of the laws of Malta.
27. 'Commonwealth Leaders' Statement on Climate Action.
28. This directive was transposed into Maltese law on the 22 December 2017 as Subsidiary Legislation 423.48 'Lifecycle Greenhouse Gas Emissions from Fuels (Amendment) Regulations'.
29. Transposed through Legal Notice 434 of 2013.
30. This was transposed by Legal Notice 403 of 2012.
31. Directive 2009/31/EC of the European Parliament and of the Council of 23 April 2009 on the geological storage of carbon dioxide and amending Council Directive 85/337/EEC, European Parliament and Council Directives 2000/60/EC, 2001/80/EC, 2004/35/EC, 2006/12/EC, 2008/1/EC and Regulation (EC) No 1013/2006.
32. Subsidiary Legislation 549.63 of the laws of Malta.
33. Subsidiary Legislation 549.81 of the laws of Malta.
34. Central Bank of Malta, Quarterly Review 2021. See www.centralbankmalta.org/site/Reports-Articles/2021/Renewable-electricity-in-Malta.pdf?revcount=6519.

Energy law in Moldova

Recent developments in the Moldovan energy market

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Interconnection of the natural gas transmission system of Romania with the natural gas transmission system of Moldova

In 2013, the Government of Moldova approved the 2030 Energy Strategy of Moldova. The strategy mentions the Moldovan authorities' intention to participate in the construction of the interconnection between the natural gas networks of Moldova and Romania through the Ungheni-Iasi section, which would allow a reversible flow of natural gas with a capacity of 1.5 billion cubic metres per year. The main goal of this project is to consolidate the energy security of Moldova, as well as to integrate Moldova into the energy market of the European Union ("EU").

The interconnection project consists of two phases. The first phase was implemented in 2014 by constructing the Ungheni-Iasi natural gas transmission pipeline and by incorporating the State Enterprise Vestmoldtransgaz ("VMTG"), a natural gas transmission system operator ("TSO"), intended to operate the Moldovan part of the Ungheni-Iasi pipeline. In 2018, the Ungheni-Iasi pipeline assets were transferred into the share capital of VMTG.

The second phase of the interconnection project was implemented by the construction of a 120km natural gas transmission pipeline, which will connect Chisinau Municipality, the capital of Moldova, and Ungheni. In 2018, the Romanian TSO, Transgaz, a Romanian state-owned monopoly, acquired VMTG and undertook the obligation to invest €93 million by 2020, including investments into the extension of the Ungheni-Iasi pipeline by constructing the Chisinau-Ungheni natural gas transmission pipeline. The Moldovan authorities announced the commencement of the construction works on 2 May 2019. The Iasi (Romania)-to-Ungheni (Moldova) gas interconnector and the Ungheni-to-Chisinau natural gas pipeline are ready for use. As of 3 December 2022, one million cubic metres of natural gas has been transported by means of these gas interconnectors and pipelines.

The importance of the Iasi-Ungheni-Chisinau natural gas transmission pipeline cannot be overestimated as it is the only pipeline ensuring an interconnection between the natural gas transmission system of Moldova and the natural gas transmission system of the EU.

Interconnection of the electricity transmission system of Romania with the electricity transmission system of Moldova

In 2017, the construction, equipping and placing into operation of a back-to-back high voltage DC converter substation in Vulcanesti was initiated. The project, which allows the electricity systems of Romania and Moldova to connect initially included a 400kV transmission line between Vulcanesti and Chisinau, the extension of the substation in Chisinau and the extension of the Vulcanesti 400kV substation. The project is part one of a venture jointly financed (up to €270 million) by the European Investment Bank, the World Bank, and the European Commission Neighbourhood Investment Facility.

On 4 November 2022, representatives of the Ministry of Infrastructure and Regional Development ("MIRD") announced that a study conducted by the World Bank had found that the construction of the Vulcanesti back-to-back substation was no longer technically and economically justified. However, the authors of the study confirmed that the construction of the 400kV transmission line between Vulcanesti and Chisinau remained necessary.

Part two of the venture consists of the construction, equipment and placing of 400kV back-to-back substation in Balti, as well as the transmission line between the two points of Balti and Suceava (the authorities' focus on which the representatives of the MIRD announced on 4 November 2022). The aim of the venture is to assist Moldova in diversifying its supply of electricity and strengthening the domestic transmission network. In particular, it allows for future integration with the ENTSO-E network.

Investigation of anti-competitive agreements on the petroleum products market

In January 2021, the Competition Council initiated an investigation against six of the biggest entities active on the petroleum product markets. In particular, these entities are accused of alleged concerted practices at setting the retail prices for the main petroleum products. To date, a decision has not been yet adopted by the Competition Council. If found to have participated in such practices, each of the investigated entities could face a fine of between 2% and 4% of the total turnover recorded in 2020. If applied, such fines could be the most substantial fines applied by the Moldovan Competition Council to date. To date, no decision has been issued by the Competition Council in this case.

New methodology for the calculation and application of prices of petroleum products

On 14 June 2021, the Board of Directors of the National Agency for Energy Regulation ("ANRE") approved the methodology for the calculation and application prices for the petroleum products ("Metholodgy").

The Methodology includes rules in relation to the:

- calculation of the maximum retail prices for petroleum products;
- determination of the maximum wholesale prices for petroleum products;
- determination by ANRE of the margin on the sale of petroleum products; and
- application by licence holders of retail and wholesale prices for petroleum products.

The Methodology also stipulates an obligation to ensure the registration of all batches of imported petroleum products and, for local procurements, records of the batches procured from importers.

Important amendments to the Moldovan Land Code

On 10 March 2022, the Moldovan Parliament introduced amendments to the Moldovan Land Code (in force as of 1 May 2022), which may be important to potential producers of renewable energy. Firstly, plots of land covered with solar photovoltaic ("PV") systems are now considered to be agricultural plots of land, subject to the harvesting of such plots or carrying out activities for the purpose of obtaining agricultural products. Additionally, the latest amendments allow the use of agricultural land for constructing wind power generation equipment. Both amendments are important to the development of the renewable energy sector, especially considering that agricultural plots of land are generally the most suitable places for the construction or installation of either PV systems or wind power generation equipment.

Moldova second district heating efficiency improvement project

On 28 November 2022, the Moldova Energy Projects Implementation Unit ("MEPIU") issued and published a request for bids for the installation of efficient cogeneration plants based on gas engines at HOB West and CHP Source 3, as well as the installation of power transformers and switchgear facilities (Plant Design, Supply & Installation).

In particular, MEPIU invited sealed Bids from eligible bidders for the design, supply, installation and commissioning of two new cogeneration plants based on Gas Internal Combustion Engines ("GICEs") in Chisinau, with a total net thermal energy production capacity of at least 43 Gcal/h, and corresponding electrical energy production capacity at the required efficiency, including:

- design, supply, installation and commissioning of a new GICE-based cogeneration plant, CHP Source 3 – on the territory of the existing CHP Source 2; and
- design, supply, installation and commissioning of a new GICE-based cogeneration plant, CHP West – on the territory of the existing HOB West.

The contract is also to include the design, supply, and installation of the facilities necessary for the supply to the national power grid of the electricity produced by the new cogeneration plants, including:

- design, supply, installation, and commissioning of a 6kV and 110kV switchgear, 6/110kV power transformers at HOB West and 110kV cable power lines for connection to the national power grid; and
- design, supply, installation and commissioning of a 6kV and 110kV switchgear at CHP Source 3; and
- the design, supply, installation, and commissioning of (i) all the necessary systems for connection of the new cogeneration plants to the natural gas supply, district heating system, water supply and sewerage systems and (ii) all the necessary electrical (high, medium, and low voltage) systems, control systems and safety systems and (iii) all other systems, including equipment and facilities, as provided in the respective bidding document.

The bids were to be submitted on or before 21 February 2023, 11:00 AM (Moldova time).

Overview of the legal and regulatory framework in Moldova

A. Electricity

A.1 Industry structure

The electricity sector of the Republic of Moldova ("Moldova") relies on the limited production sources located on Moldovan territory and controlled by its constitutional authorities (combined heat and power ("CHP") plants and a hydropower plant, covering about 21% of the consumption of Moldova (except in the Transnistria region) in 2021). About 79% of Moldova's consumption was covered in 2021 through supplies by 'Cuciurgani-Moldavskaya GRES' (a gas-fired power plant located in the Transnistria region and owned by the Russian company 'Inter-RAO') and/or by Ukrainian companies.

In 2022, the electricity market of the Republic of Moldova was strongly influenced by the invasion of the Russian Federation into Ukraine. As a result, Moldova was left without a secure supply of electricity. Agreements relating to the supply of electricity have since been concluded on a monthly basis. Until September 2022, 'Cuciurgani-Moldavskaya GRES' covered approximately 67% of the electricity supplied to Moldova, whereas 28% were covered by Ukrainian suppliers and only 4-5% were covered by local suppliers. The crisis deepened in October 2022, when the Ukrainian authorities banned the export of electricity to other countries. This escalated further in November 2022, when no agreement was concluded with 'Cuciurgani-Moldavskaya GRES', due to disagreements over the supply of natural gas. In December 2022, approximately 47% of the electricity was supplied to Moldova by 'Cuciurgani-Moldavskaya GRES', approximately 31% from local sources (including 3.5% from renewable sources), whereas the remaining quantity was supplied by Romanian suppliers.

As a contracting party to the Energy Community Treaty since 1 May 2010, Moldova has a continuous obligation to implement the energy *acquis* in force. In this context, the primary legislation in the electricity domain is constituted of the Electricity Law, partially transposing the Third Electricity Directive, the Electricity Regulation, and Directive 2005/89/EC of the European Parliament and of the Council of 18 January 2006. In addition, on 21 September 2017, the Moldovan Parliament adopted the Energy Law.

The Electricity Law and the Energy Law establish a general legal framework for the organisation and regulation of the Moldovan energy sectors (and, in particular, the electricity sector). The provisions are intended to ensure the efficient functioning and monitoring of the Moldovan energy sector and to create conditions for the liberalisation of the electricity market and the promotion of competition on such market. Moreover, as of the Electricity Law coming into force, the electricity market of Moldova was declared open, whereby each customer had the right to choose and change their supplier.

Under the Electricity Law,[1] the following activities are subject to regulation:

- production of electricity;
- operation of the electricity market;
- transmission of electricity;
- centralised management of the electricity system;
- distribution of electricity; and
- supply of electricity.

Such activities are conducted based on licences issued by the National Agency for Energy Regulation ("ANRE"). ANRE, as the national regulator of the Moldovan electricity sector, also monitors and controls the compliance of licenced entities with licence conditions. The licences for the activities indicated at (i), (iii), (iv) and (v) above are issued for 25 years, whereas the licences for the activities indicated at (ii) and (vi) above are issued for ten years.[2] The licence for the production of electricity is only issued to a producer operating a power plant of not less than 5MW and of not less than 20MW, in case the power plant is for internal use only.

The following five entities hold licences for the production of electricity: *Termoelectrica S.A., CET-Nord S.A., Picador-Grup S.R.L., Nodul Hidroenergetic Costesti I.S.* and *Moldavskaya GRES* (located in Transnistria region, not controlled by Moldovan constitutional authorities). *Moldelectrica I.S.* is the only entity that holds a licence for the transmission of electricity. Additionally, two entities hold licences for the distribution of electricity (*RED Nord S.A.* and *I.C.S. RED Union Fenosa S.A.*) and 62 entities hold licences for the supply of electricity.[3]

A.2 Third party access regime

Transmission system operators ("TSOs") and distribution system operators ("DSOs") must grant access to the transmission and distribution networks to all system users, in a transparent and non-discriminatory manner, taking into consideration the priority status of generating installations producing combined heat and power in the dispatching process. The access to transmission and distribution networks is granted at regulated tariffs. A refusal to grant access to the networks is only permitted where the respective operator lacks the necessary capacity (eg there is no electricity network or the existing electricity network does not have the technical capacity to fulfil the applicant's requirements). Every refusal of granting access to a transmission or distribution network is to be notified to ANRE.[4]

In this context, ANRE adopted the Regulation 168/2019, which regulates (a) the steps, procedures, terms and conditions of access of the users' installations and of the production facilities to the system operators' electricity networks; (b) the legal relations between the system operators and the system users regarding the electricity distribution and transmission services; as well as (c) the terms and conditions of cessation of supply of electricity distribution and transmission services, of interruption, and limitation of supply of electricity, of disconnection and reconnection to the electricity networks of the users' installations and of the production facilities.

A.3 Market design

The electricity market of Moldova is regulated, meaning that activities on the market are subject to licencing (see section A.1) and consequently, licenced entities must comply with certain conditions and are monitored and controlled by ANRE, as national regulator.

In addition, the Electricity Law provides for certain unbundling rules applicable to producers, TSOs and DSOs, and therefore:

- a producer of electricity must be independent, from a legal point of view, from any entity conducting the activity of transmission or distribution of electricity;[5]
- a TSO must be independent from any electricity undertaking conducting activities, which are not related to transmission of electricity;[6] and
- a DSO (which is part of an integrated undertaking) must be independent from any activities, which are not related to distribution of electricity.[7]

A.4 Tariff regulation

General rules on prices and tariffs in the electricity sector are contained in the Electricity Law. In addition to this, ANRE adopted certain secondary legislation in this respect, such as the Regulation 286/2018, as well as methodologies on the calculation, approval and application of tariffs and prices in several sub-sectors of the electricity sector (eg transmission, distribution, auxiliary services, etc).

The Electricity Law[8] allows the application of both negotiated prices and regulated prices and tariffs. The following constitute regulated prices and tariffs:

- regulated prices for electricity and heating energy produced by CHP plants;
- regulated tariffs for electricity transmission services;
- regulated tariffs for electricity distribution services;
- regulated prices for the supply of electricity by the supplier of last resort and the supplier of universal services;
- regulated tariffs for auxiliary services supplied by the TSO and the DSO;
- regulated tariffs for the service of operation of the electricity market; or
- regulated prices for electricity supplied by the central electricity supplier.

The regulated prices and tariffs indicated above are determined in accordance with the methodologies prepared and approved by ANRE. These methodologies are published in the Official Gazette of Moldova, on the official website of ANRE and on the official websites of the respective electricity undertakings.[9]

The regulated prices and tariffs are determined by the respective electricity undertakings and submitted to ANRE for examination and (*ex-ante*) approval. The request for examination of the prices and/or tariffs is submitted to ANRE annually, before 1 February.[10] The general rule is that the decisions of ANRE relating to the requests of licence holders shall be taken within 180 calendar days from the date that the request is registered,[11] and published in the Official Gazette of Moldova, on the official website of ANRE and on the official websites of the respective electricity undertakings. After approval of the prices and tariffs, ANRE supervises and monitors the application of such prices and tariffs by the electricity undertakings.[12]

A.5 Market entry

As indicated at section A.1, activities in the electricity sector are conducted on the basis of licences issued by ANRE. Under certain conditions, ANRE also has the right to decide on the suspension and/or withdrawal of the licence.

The requirements that must be fulfilled in order to obtain a licence depend on the type of electricity sector activity intended to be conducted. Generally, applicants must (a) be registered in Moldova, (b) submit their financial statements for the previous year or a bank account excerpt (in the case of a newly incorporated entity), and (c) have qualified personnel for conducting the respective activity.

Additionally:

- the proof of technical resources necessary for conducting the respective activity (power plant, transmission network, distribution network) is necessary for obtaining a licence for the transmission, distribution and production of electricity;
- the appointment as operator of the electricity market must obtain a licence for the operation of the electricity market; and
- control centres must obtain a licence for the centralised management of the electricity system.[13]

It takes 15 calendar days for ANRE to examine the declarations and the accompanying documents on the issuance or prolongation of a licence in the electricity sector.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

ANRE or the Government of Moldova ("GoM") may impose PSOs on undertakings operating in the electricity sector, in the general economic interest. PSOs may relate to matters of security, including security of supply, regularity, quality and price of supplies, environmental protection, protection of life, health, and property as well as measures on the protection of end customers.[14] The PSOs may be imposed particularly on entities conducting activities in the domain of production, transmission, distribution and/or supply of electricity, and such PSOs may be related to security of supply. Every two years, the Ministry of Economy and Infrastructure of Moldova (the "MoEI"), on the basis of the information presented by ANRE, submits reports referring to the fulfilment of the PSOs by the electricity undertakings to the GoM and the Energy Community Secretariat (the "EnCS"). When it comes to the electricity domain, PSOs are currently imposed to the electricity suppliers S.A. Furnizarea Energiei Electrice Nord and to I.C.S. Premier Energy S.R.L. (both until 2026).

Smart metering

The DSOs may install smart meters (allowing hourly recording of the consumed electricity) but only after proving the economic efficiency of such measures and after approval by ANRE.[15]

Electric vehicles

The main incentive for the acquisition and use of electric vehicles ("EVs") in Moldova is the exemption (if compared to gasoline or diesel engine vehicles) from the obligation to pay the excise when importing EVs into Moldova.

A.7 Cross-border interconnectors

Moldova shares borders with Romania (to the West) and Ukraine (to the North, East and South). The parallel operation of the electric power systems between Moldova and Ukraine is performed through seven 330kV overhead lines and eleven 110kV overhead lines, while the islanded mode of operation of the electric power systems of Romania and Moldova is performed through one 400kV overhead line (Vulcanesti – Isaccea) and four 110kV overhead lines.[16]

I. Existing interconnectors:[17]

- *Moldova - Romania*:
  - Overhead line 400kV Vulcanesti - Isaccea;
  - Overhead line 110kV Costesti - Stanca;
  - Overhead line 110kV Cioara - Husi;
  - Overhead line 110kV Ungheni - Tutora; and
  - Overhead line 110kV Gotesti - Falciu.
- *Moldova – Ukraine*:
  - Overhead line 330kV CERS Moldoveneasca – Novoodeskaia;
  - Overhead line 330kV CERS Moldoveneasca – Usatovo;
  - Overhead line 330kV CERS Moldoveneasca – Podolskaia;
  - Overhead line 330kV CERS Moldoveneasca – Artiz;
  - Overhead line 330kV Podolskaia – Ribnita 1;
  - Overhead line 330kV Podolskaia – Ribnita 2;
  - Overhead line 110kV CERS Moldoveneasca – Beleaevka;
  - Overhead line 110kV CERS Moldoveneasca – Razdelinaia;
  - Overhead line 110kV CERS Moldoveneasca – Starokazace;
  - Overhead line 110kV Vasilievka – Kr. Okni;
  - Overhead line 110kV Vulcanesti – Bolgrad 1;
  - Overhead line 110kV Vulcanesti – Bolgrad 2;
  - Overhead line 35kV Etulia – Nagornaia;
  - Overhead line 330kV Balti – CHE Dnestrovsk;
  - Overhead line 110kV UZ Briceni – CHE Dnestrovsk;
  - Overhead line 110kV Ocnita – Sahti;
  - Overhead line 110kV Otaci – Nemia;
  - Overhead line 110kV Larga – Nelipovti;
  - Overhead line 110kV Poroghi – Soroca; and
  - Overhead line 10kV Mamliga – Criva.

II. Projects:

- Overhead line 400kV Balti – Suceava; and
- Overhead line 400kV Iasi – Ungheni - Straseni.

Private parties, which are not TSOs, cannot operate interconnectors.

B. Oil and gas

B.1 Industry structure

Oil

As per the 2021 ANRE Activity Report,[18] the consumption of oil products in Moldova is mainly ensured by imported petroleum products. In 2021, the volume of imported petroleum products constituted 883,287 tons (648,867 tons of diesel; 173,325 tons of gasoline; and 61,094 tons of Liquified Petroleum Gas ("LPG")). The main supplier of petroleum products to Moldova in 2020 was Romania (with a share of 56.20% for diesel and 99.35% for gasoline). Other noteworthy suppliers of petroleum products are the Russian Federation, Turkey, Bulgaria, Turkmenistan, Belarus, and Kazakhstan. Additionally, pursuant to the Energy Balance of Moldova for 2021, a volume of only 5,000 tons of petroleum products was covered by the means of primary production.

The main normative act regulating the Moldovan petroleum products sector is the Petroleum Products Market Law. The aim of this law is to create an organisational, legal, and economic framework to ensure Moldova's economic security and to regulate the importation, transportation, storage and sale of petroleum products, as strategic products. In this context, a licencing regime is provided for the following activities:

- import and wholesale of diesel and gasoline;
- import and wholesale of LPG;
- retail of diesel and gasoline; and
- retail of LPG.[19]

The licences are issued by ANRE for a period of five years.[20] As per the data published by ANRE on its official website, 27 licences have been issued for the import and wholesale of diesel and gasoline, 14 licences for the import and wholesale of LPG, 82 licences for the retail sale of diesel and gasoline using fuel stations and 74 licences for the retail sale of LPG using fuel stations.

Natural gas

In 2021, the entire volume of natural gas for the Moldovan market (1205.7 million cubic metres) was imported.[21] The main player on the Moldovan natural gas market is Moldovagaz SA ("MG"), a supplier of natural gas. The shareholders of MG are Gazprom (50%), Moldova (35.33%), the Committee of Management of the Property of Transnistria (13.44%) and certain minority shareholders (1.23%). As a supplier of natural gas, among other things, MG:

- concluded an agreement with Gazprom on the supply of natural gas;
- is the founder (sole shareholder) of the 12 main natural gas DSOs. As specified by the reports of the DSOs, the total length of the natural gas network of these operators is 21,750.50km;[22] and

- is the founder (sole shareholder) of Moldovatransgaz SRL ("MTG"), the main Moldovan TSO. Among other things, MTG maintains the gas transit on Moldova's territory through trunk pipelines to the underground storage facility in Bohorodchany (Ukraine) and the Balkan region. MTG transmit the natural gas using its transmission network (including magistral pipelines with a total length of 656.24km and pipeline branches with a total length of 903.42km).[23]

In 2022, similarily to the electricity market, the natural gas market of the Republic of Moldova was strongly affected by the invasion of the Russian Federation into Ukraine and by the deterioration of the business relations between Gazprom and its clients within the European Union and the Republic of Moldova. Starting with October 2022, the quantity of the natural gas supplied by Gazprom to the Republic of Moldova was significantly lower than the demand of Moldovan consumers (both on right side and on the left side of the Dniester River) and lower than the quantities originally indicated in the agreements signed between MG and Gazprom. Although the agreement concluded between MG and Gazprom appeared to indicate a quantity of 406 million cubic metres to be supplied to the Republic of Moldova in December 2022 (including 217 million cubic metres for the Transnistria region), only 177 million cubic metres of natural gas have been supplied. An improvement of this situation is not foreseeable in January 2023.

The GoM seems to be aware that, in order to ensure a secured supply of natural gas, certain measures must be taken. For example, diversifying supply sources (including by identifying local sources), implementing LNG-related projects and building natural gas storage facilities.[24] (For the short-term period, it appears that the GoM has ensure, by means of the state-owned entity Energocom S.A., the acquisition and storage of approximately 230 million cubic metres of natural gas (as per the data in the beginning of December 2022)[25], which is enough to meet the demand of natural gas of the Republic of Moldova (excluding the Transnistria region) for approximately 2 months of winter.)

Also, it is to be mentioned that in 2014 a new TSO was established: I.S. Vestmoldtransgaz ("VMTG"). The VMTG shareholders are Eurotransgaz S.R.L. (75% shareholding and entirely owned by Transgaz S.A. (Romanian TSO)) and the European Bank for Reconstruction and Development (25% shareholding). VMTG operates the Iasi (Romania) to Ungheni (Moldova) gas interconnector (with a total length of 43.2km) and the Ungheni to Chisinau natural gas pipeline. The Iasi (Romania) to Ungheni (Moldova) gas interconnector and the Ungheni to Chisinau natural gas pipeline are active and as of 3 December 2022, one million cubic metres of natural gas have been transported by means of these gas interconnector and pipeline[26].

As mentioned at section A.1 above, Moldova is a Contracting Party to the Energy Community Treaty. Therefore, Moldova has a continuous obligation to implement the energy *acquis* in force. In this respect, the Parliament of Moldova adopted the Natural Gas Law, partially transposing the Third Gas Directive, the Gas Regulation, and the Directive 2004/67/EC of the Council of 26 April 2004. The aim of the Natural Gas Law is to establish a general framework for the organisation and regulation of the natural gas sector in order to ensure the efficient functioning and monitoring of the gas market.

Notably, as of 1 January 2020, the TSOs must comply with the TSO unbundling rules of the Third Gas Directive (ie TSOs must implement one of the unbundling models: FOU, ITO or ISO). Unbundling obligations shall also apply to DSOs, storage operators and suppliers of natural gas.

Under the Natural Gas Law,[27] the following activities are subject to licences issued by ANRE:

- production of natural gas;
- transmission of natural gas;
- distribution of natural gas;
- storage of natural gas;
- trading of natural gas;
- supply of natural gas; and
- supply of compressed natural gas for vehicles by means of fuel stations.

The licences for the activities indicated at (i) - (v) above are issued for 25 years, whereas the licence for the activity indicated at (vi) above is issued for ten years.[28] Pursuant to the data published by ANRE on its official website, ANRE issued two licences for the transmission of natural gas (to MTG and VMTG), 25 licences for the supply of natural gas at regulated tariffs, 21 licences for the distribution of natural gas and five licences for the supply of natural gas at non-regulated tariffs (by means of compressed natural gas stations)[29].

B.2 Third party access regime to gas transportation networks

As per the Natural Gas Law, a TSO must grant access to its natural gas transmission network to existing/potential users in a transparent, objective, and non-discriminatory manner, on the basis of an agreement and at tariffs established in accordance with the methodology approved by ANRE.[30] The TSO must publish the information necessary to ensure efficient access to its gas transmission network on its website.[31]

To manage the access of third parties to the gas transmission system, the TSO must keep an electronic register indicating the information with regard to each access point, identified by a specific number, including the identity of the third party, the existing supplier, the address of the consumption point, the contracted flow, the connection point, the delimitation point, the pressure in the delimitation point and the characteristics of the measuring equipment, as well as information on whether the respective consumption point is connected or disconnected.[32]

Access to the natural gas transmission network can generally be refused: (a) in absence of system capacity, (b) where granting access would impede the TSO to execute its PSOs, or (c) where serious economic and financial difficulties would be incurred due to the 'take or pay' obligations.[33]

A TSO refusing access to the system due to insufficient capacity must take necessary measures to ensure the access of the third party to the system, under the condition that (i) such measures are economically justifiable, or (ii) the third-party requesting access is ready to bear the costs in connection with necessary measures.[34]

The TSO must inform ANRE about each case of congestion and refusal of access to the natural gas transmission system, as well as about the measures which are intended to be taken to resolve such situations.[35]

B.3 LNG terminals and storage facilities

Currently, there are no liquified natural gas ("LNG") facilities in Moldova. While LNG is not expressly excluded from the scope of the Natural Gas Law, the latter does not contain LNG-specific norms.

B.4 Tariff regulation

General rules on prices and tariffs in the natural gas sector are provided by the Natural Gas Law. Additionally, ANRE adopted certain secondary legislation, including Regulation 286/2018 and methodologies on the calculation, approval and application of tariffs and prices in several sub-sectors of the electricity sector (eg, transmission, distribution, auxiliary services, etc).

The Natural Gas Law[36] allows the application of both negotiated prices and regulated prices and tariffs. The following constitute regulated prices and tariffs:

- regulated tariffs for natural gas transmission services;
- regulated tariffs for natural gas distribution services;
- regulated tariffs for natural gas storage services;
- regulated prices for the supply of natural gas by the supplier of last resort, in the context of PSO; or
- regulated tariffs for auxiliary services supplied by the TSO and the DSO.

The regulated prices and tariffs are determined in accordance with the methodologies prepared and approved by ANRE. These methodologies are published in the Official Gazette of Moldova, on the official website of ANRE and on the official websites of the respective natural gas undertakings.[37]

Like the electricity sector, the regulated prices and tariffs are determined by the respective natural gas undertakings and submitted to ANRE for examination and (*ex-ante*) approval. The request for examination of the prices and/or tariffs is submitted to ANRE annually, until 1 February.[38] As a general rule, the decisions of ANRE on the requests of the licence holders are taken within 180 calendar days as of the registration date of the request[39] and published in the Official Gazette of Moldova, on the official website of ANRE and on the official websites of the respective natural gas undertakings. After approval of the prices and tariffs, ANRE supervises and monitors the application of such prices and tariffs by the natural gas undertakings.[40]

B.5 Market entry

Oil

The Petroleum Products Market Law imposes certain special requirements on importers of petroleum products, to ensure the energy security of the country:

- importers of gasoline and/or diesel must hold gasoline/diesel storage with a capacity of at least 1,000 cubic metres; and
- importers of LPG must hold storages for the storage of LPG with a capacity of at least 150 cubic metres.[41]

Under certain conditions, farmers are exempted from the requirement to hold a licence for the import of petroleum products (diesel). They must, however, request an authorisation from ANRE,[42] issuable in case the respective farmer cumulatively fulfils the following conditions:

- owns or leases agricultural land;
- owns or leases diesel storages; and
- owns or leases agricultural equipment functioning on basis of diesel.[43]

The diesel import authorisation indicates the quantity of diesel to be imported (based on the area of agricultural land owned and/or leased).[44] Pursuant to the information published by ANRE, there are no such types of authorisations currently issued.

The export (re-export) of petroleum products can only be performed by the importers of petroleum products (ie, by entities holding licenses for the import of petroleum products) and on the basis of an authorisation granted by ANRE.

Regarding the licences for the retail sale of main petroleum products (diesel and gasoline) and LPG, the main condition for the applicant is the possession of a certified fuel station. Furthermore, the applicant must possess separate capacities for the storage of the main petroleum products and submit with ANRE a positive expertise conclusion issued by an expertise body in the domain of industrial security.[45]

Natural gas

As mentioned at section B.1 above, activities in the natural gas sector are conducted on the basis of licences issued by ANRE. Under certain conditions, ANRE has the right to decide on the suspension and/or withdrawal of licences. There are certain general requirements for the obtaining of the licence: the applicants must (a) be registered in Moldova, (b) submit their financial statements for the previous year or a bank account excerpt (in the case of a newly incorporated entity), and (c) have qualified personnel for conducting the activity. Additional requirements also apply to the activities of production, transmission, distribution, storage, and supply of compressed natural gas for vehicles by means of fuel stations. Such activities require certain technical resources for conducting the respective activity (production installation, transmission network, distribution network and storage).[46]

It takes 15 calendar days for ANRE to examine the declarations and accompanying documents on the issuance of a licence in the natural gas sector.

ANRE has the right to refuse the issuance of the licence for the transmission of natural gas in case the TSO is not certified. A request for certification is filed by the TSO with ANRE, if such operator fulfils the independence and unbundling requirements. Within four months of the submission of a request, ANRE must decide the provisory certification of the TSO. The decision on provisory certification is notified to the EnCS within five business days, as of the date of adoption. Within four months, as of the date of notification, the EnCS issues its conclusion on the compliance of the TSO with the certification requirements. Furthermore, ANRE adopts a decision on the certification of the TSO (taking into consideration the conclusion of the EnCS) within two months. The decision and the conclusion of the EnCS are published in the Official Gazette of Moldova, as well as on the official websites of ANRE and the Energy Community. If the decision of ANRE differs from the conclusion of the EnCS, both are published, along with the reasons for the final decision.[47]

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

ANRE or the GoM may impose PSOs on operations in the natural gas sector, where this is in the general economic interest. PSOs may relate to security, including security of supply, regularity, quality and price of supplies, environmental protection, protection of life, health, and property, as well as measures on the protection of end customers.[48] PSOs may be particularly imposed on entities conducting activities in the domain of transmission, distribution, storage and/or the supply of natural gas. Every two years, the MoEI, on the basis of the information presented by ANRE, submits to the GoM and the EnCS reports regarding the fulfilment of the PSOs by the natural gas undertakings.

Smart metering

The DSOs may install smart meters or remote data transmission devices at consumers' households and in the regulation-measuring stations at the entrance of the localities (allowing hourly recording of the consumed natural gas) only after proving the economic efficiency of such measures and after approval by ANRE.[49]

B.7 Cross-border interconnectors

Existing interconnectors:[50]

- *Moldova – Ukraine*:
  - Ananiev-Tiraspol-Ismail (Grebeniki);
  - Razdelinaia – Ismail (Grebeniki);
  - Sebelinca – Dnepropetrovsk – Krivoi Rog – Ismail (Grebeniki);
  - Ananiev – Cernauti – Bohorodchany (Alexeevca - Ananiev); and
  - Odesa – Chisinau.
- *Moldova – Romania*:
  - Iasi – Ungheni.

C. Energy trading

C.1 Electricity trading

All transactions on the sale and purchase of electricity and other ancillary products are executed on the electricity market, which consists of the electricity wholesale market and the electricity retail market.[51]

The transactions on the sale and purchase of electricity, including transactions of import or export, transactions of the sale and purchase of electricity for coverage of the technological consumption and electricity losses, electricity balancing, interconnection capacities, system services, other ancillary products, with participation of the producers, TSOs, DSOs, electricity market operator, the central supplier of electricity and other suppliers, are concluded on the electricity wholesale market.

The wholesale market consists of the bilateral agreements market and the organised electricity markets.[52]

On the bilateral agreements market, the sale and purchase transactions are made on the basis of bilateral agreements, taking into consideration the supply and demand, as a result of competitive mechanisms or negotiations. By derogation, the central supplier of electricity acquires electricity from the eligible power plants producing electricity from renewable energy sources ("RES") and the electricity from CHPs. The central supplier then resells such electricity to suppliers in accordance with the algorithm set by ANRE and at regulated prices approved by ANRE.[53]

On the organised electricity markets, the participants conclude transactions on the sale and purchase of electricity, interconnection capacities, system services and other ancillary services by means of the operator of the electricity market. On the organised electricity markets, prices are based on supply and demand, as a result of competitive mechanisms or negotiations. Under the Electricity Law, the following are considered organised electricity markets: the day-ahead electricity market, the intra-day market, the organised agreements market, the balancing market, and the system services market.[54]

The operator of the electricity market is responsible for the organisation and management of the day-ahead electricity market, the intra-day market and the organised market of agreements. The market of allocation of interconnection capacities, the balancing market and the system services market are, however, organised and managed by the TSO.[55]

In order to participate in the organised electricity markets, the interested persons must register with the operator of the electricity market or with the TSO (depending on the concrete market) and submit financial guarantees.[56]

The transactions on the sale and purchase of electricity between suppliers and end consumers (for coverage of own consumption of end consumers) are executed on the retail market of electricity, on the basis of agreements on the supply of electricity concluded between the suppliers and the end consumers.[57] On the retail market of electricity, suppliers sell electricity to end consumers at negotiated prices. However, in the context of PSOs, the suppliers of last resort and the suppliers of universal services supply electricity to end consumers at regulated prices.[58]

C.2 Gas trading

In 2021, 98.5% of the volume of natural gas for the Moldovan market was acquired from Gazprom. The agreement on the supply of natural gas to the Moldovan market was concluded between Gazprom and MG (a 50% Gazprom subsidiary). The agreement between MG and Gazprom for 2021 – 2026 is based on a Hybrid price formula (Q4 and Q1 - 30% x Dutch Title Transfer Facility ("TTF")[59] gas price + 70% x Platts prices for a mix of petroleum products; Q2 and Q3 - 70% x TTF gas price + 30% x Platts prices for a mix of petroleum products). Besides MG, there are 26 other licenced suppliers of natural gas on the market.

There is an assumption of an open natural gas market under the Natural Gas Law. All the transactions on the sale and purchase of natural gas and other ancillary products are executed on the natural gas market, which consists of the natural gas wholesale market and the natural gas retail market.[60]

The transactions on the sale and purchase of natural gas, including transactions of import or export, transactions of sale and purchase of interconnection capacities, with participation of the producers, TSOs, DSOs, storage operators and suppliers are concluded on the wholesale natural gas market. On the wholesale market, the sale and purchase transactions are made on the basis of bilateral agreements, taking into consideration supply and demand, as a result of competitive mechanisms or negotiations.[61]

Transactions on the sale and purchase of natural gas with end consumers are executed on the retail market of natural gas, on the basis of agreements on the supply of natural gas concluded between the suppliers and the end consumers. The supply of natural gas to household consumers and small enterprises is generally performed at regulated prices.[62]

Irrespective of the type of market (wholesale or retail), the transactions must be executed in accordance with the Natural Gas Market Rules. Such Natural Gas Market Rules have been approved by means of the Decision no. 534/2019.

As of 2022, certain provisions regarding the gas trading have been inserted into the Natural Gas Law. It is indicated that the trader shall conducts its activity exclusively on the wholesale natural gas market, on basis of a license for natural gas trading, in accordance with the Natural Gas Law and the Natural Gas Market Rules. If the trader carries out other activities on the natural gas market, such must ensure the accounting separation.

The trader must submit to ANRE semi-annual reports regarding the activity carried out on the wholesale natural gas market, as well as other requested information, in the manner and terms established by ANRE.

The licence for the supply of natural gas ensures all the trading rights in relation to a trader and grants the supplier the right to conduct all of its trading activities. On the other side, a trader cannot simultaneously hold the natural gas trading licence and the licence for the supply of natural gas.

D. Nuclear energy

Nuclear energy is not generated in Moldova.

The main national act in this respect is Law no. 132/2012. Moldova is also a contracting party to a number of international treaties, including the Treaty on the Non-Proliferation of Nuclear Weapons of 1968, the Statute of the International Atomic Energy Agency, the Convention on Civil Liability for Nuclear Damage of 1963, the Convention on the Physical Protection of Nuclear Material of 1979, the Convention on Early Notification of a Nuclear Accident of 1986, the Convention on Assistance in the Case of a Nuclear Accident or Radiological Emergency of 1986, the International Convention for the Suppression of Acts of Nuclear Terrorism, etc.

E. Upstream

There are no natural gas extracting activities in Moldova (in 2021 and H1 2022, the natural gas for the Moldovan market was entirely imported). Regarding oil, the extracted quantities are limited.

F. Renewable energy

F.1 Renewable energy

The main normative act regulating the renewable energy sector is the Renewables Law.[63]

Among other things, this law sets the target to achieve a 17% share of energy from RES in the gross final consumption of energy by 2020.[64] No other targets have been set for the period after 2020. It is, however, to be taken into consideration that a new Moldova Energy Strategy 2050 (the concept of which has been presented in December 2022) is currently being prepared.

Pursuant to the information published by the Energy Efficiency Agency of Moldova (subordinate to MoEI) ("EEA"),[65] the share of energy from RES in the gross final energy consumption of 2020 constituted 25.06% (mostly constituted of biomass used for heating in the rural areas). This share should increase in the next few years due to the current energy crisis. The increase in the quantity of electricity generated from renewable sources in 2021 can be considered a sign of such potential development (116,552,000kWh) if compared to 2020 (81,353,000kWh).[66] Pursuant to the Register of Eligible Producers kept by ANRE, 183 producers of electricity from RES, with a cumulative installed power of 120MW, have the status of eligible producers.[67] In addition, there are 58 producers of electricity from RES (with a cumulative installed capacity of 37.5MW) which obtained a tariff under the provisions of the previous renewable energy law.[68]

The concept of the Moldova Energy Strategy 2050 mentions that since Moldova does not hold primary energy sources, the authorities must focus on RES. In this context, the Moldovan authorities are to support construction of new renewable energy installations with a total installed capacity of 410MW.[69]

Under the Renewables Law, the following activities are subject to licencing: production of electricity from RES, production of thermal energy from RES, production of biogas to be supplied into the natural gas networks, and biofuel to be acquired by the importers of main petroleum products.[70]

Producers of electricity from RES and producers of biogas have non-discriminatory and regulated access to the respective networks (against published, non-discriminatory, cost-based, transparent, and foreseeable tariffs).[71]

Beside this, producers of electricity from RES benefit from other incentives, such as:

Fixed price/fixed tariff:

- fixed price, set within a tender, for eligible producers operating a power plant with a capacity exceeding the capacity limit established by the GoM; and
- fixed tariff, set by ANRE for eligible producers operating a power plant with a capacity not exceeding the capacity limit established by the GoM (but not less than 10kW).[72]

Priority dispatch:

The TSOs and DSOs must grant priority to electricity produced from RES at the dispatching of electricity production capacities, to the extent that the security of the electricity system is not affected.[73]

Guarantees of origin

Under the Renewables Law, Guarantees of Origin ("GOs") are instruments evidencing the origin of electricity generated from RES.[74] The GOs are issued by the central supplier of electricity, upon the request of the producer and can be transferred from one electricity producer to another, from an electricity producer to a supplier of electricity and from one supplier of electricity (holding the GO) to another. Upon the request of a participant to the electricity market, ANRE recognises the GOs issued by the authorities of the member states of the European Union ("EU) or of the states which are parties of the Energy Community.[75]

In 2022, the Moldovan Parliament introduced amendments to the Land Code.[76] In particular, plots of land covered with solar photovoltaic ("PV") systems are now considered to be agricultural plots of land, subject to harvesting of such plots or carrying out activities for the purpose of obtaining agricultural products.[77] Moreover, the latest amendments allow the use of agricultural land for the purpose of constructing wind power generation equipment.[78] Both amendments are important to the development of the renewable energy sector considering that the most suitable places for the construction and installation of either PV systems or wind power generation equipment are agricultural plots of land.

F.2 Renewable pre-qualifications

The GoM adopted Regulation 690/2018 on the conducting of auctions for the offering of the status of eligible producer. Pursuant to this regulation, in order to participate with an auction the investor must meet the following conditions:[79]

- must not be involved in an insolvency process, does not have its assets seized, is not involved in a liquidation or reorganisation process, its activities are not suspended;
- prove that it has experience in construction and/or exploitation of power plants (for the respective type of technology);
- must not have had its licence (if held) suspended or withdrawn;
- must not conduct concomitantly the activity of TSO or DSO;
- the equipment of the power plants using RES must not be previously used (manufactured not earlier than 48 months before the putting into use of the respective power plant);
- in case of cogeneration power plants (using biomass as fuel), only production technologies with an overall efficiency of at least 80% are used;
- prove the fulfilment of the criteria regarding the viability and credibility of the project:
- the technical credibility of the project:
  - the excerpt from the power plant execution technical project (confirming the compliance of the project with the auction documentation, the efficiency of the used technology and equipment, etc);
  - the project implementation calendar;
- the financial credibility of the project:
  - business plan;
  - financing plan;
  - confirmation of existence of funds for the financing of the project;
- the eligibility of the plot of land on which the plant is to be constructed:
  - the plan confirming the location of the plant;
  - list of plots of land;
  - the original and copies confirming the rights on connection with the plots of land (ownership, lease);
  - confirmation of change of the destination of the land (for agricultural land); and
- the credibility of connection of the plant to the grid:
  - the connection notice issued by the respective system operator.

F.3 Biofuel

The production of biofuel is regulated by the Renewables Law. The law sets a target of a 10% share of energy from RES in the transport energy consumption by 2020[80] (compared to 4% in 2015). Unfortunately, Moldova is far from reaching this target (below 1% in 2020).[81]

As mentioned at section F.1 above, the production of biofuel is subject to licensing under the Renewables Law. To obtain a licence for the production of biofuel (issuable for a term of 25 years), the applicant has to provide documents confirming that they are registered in Moldova and the financial statements for the previous year or a bank account excerpt (in case of a newly incorporated entity).

The importers of main petroleum products must annually acquire (from local or foreign producers) quantities of biofuel to be used in the main oil products mix, to reach the minimum annual level set by ANRE.[82]

G. Climate change and sustainability

G.1 Climate change initiatives

The main normative act in this domain remains as the Renewables Law, creating the necessary framework for the application of the Renewable Energy Directive.

Further, the National Program 2011-2020 set priority actions and policies, as a response to risks related to an increase of energy prices, dependence on the import of energy and the impact of the energy sector on climate change. A similar course of action is provided by the EE National Plan 2019-2021.

To decrease Moldova's dependence on the import of energy and the impact of the energy sector on climate change, the National Program 2011-2020 provides for the following general targets for Moldova:

- an increase in the efficiency of the global consumption of primary energy of 20% by 2020;
- an increase of the share of renewable energy from 6% in 2010 to 20% in 2020;
- an increase of the share of biofuels to at least 10% in 2020; and
- at least 25% cuts in greenhouse gas ("GHG") emissions (compared to levels of 1990).

The public authority implementing Moldova's policies in the domain of energy efficiency is the EEA.

It must be noted that the GoM instituted a mechanism of activities' coordination in the domain of climate change (by means of Decision no. 444/2020). Decision no. 444/2020 approves the componence of the National Commission for climate change, the Regulation on organisation and activity of the National Commission for climate change, the Regulation on the mechanism of coordination of the process of adaptation to the climate change and the Regulation on the mechanism of coordination of adequate actions of attenuation at a national level.

G.2 Emission trading

The Reduced Emissions Strategy sets targets for gas emissions until 2030 (a minimum cut of: 65% in gas emissions in the energy sector, 15.8% in the industrial processes sector and 30.4% in the agricultural sector).

On 27 June 2017, Moldova, the EU and the European Community of Atomic Energy and their member states concluded the Association Agreement. As per the Association Agreement, Moldova agreed to progressively make its legislation closer to the Directive 2003/87/EC of the European Parliament and of the Council of 13 October 2003. In particular, the Moldovan authorities must prepare a list of installations falling under the Directive 2003/87/EC and a GoM Decision on the creation of a system of monitoring, reporting and verifying the GHG emissions.

On 26 December 2018, the GoM adopted the Decision no. 1277/2018 on the institution and functioning of the National System on monitoring and reporting of GHG emissions and of other relevant information for climate change. The National System is constituted of the inventory system (aiming at evaluation of the current situation) and of the policies, measures and forecast system (for the purpose of the progress evaluation).

G.3 Carbon pricing

No carbon pricing rules have been adopted by the Moldovan authorities.

G.4 Capacity markets

On 7 August 2020, ANRE adopted the Electricity Market Rules, which entered into force on 2 October 2021.

Such rules set the principles, rules and mechanisms for the formation of prices and trade relations on the wholesale electricity market between participants to the electricity market, regulate the terms and conditions of the organisation and operation of the electricity market, including the market for bilateral electricity contracts, the day-ahead electricity market, the daytime electricity market, the balancing electricity market and the system services market, the rights and obligations of electricity producers, electricity suppliers, DSOs and the electricity market operator, the TSO regarding the management of such markets. The provisions contained on the Electricity Market Rules regarding the capacities are general.

H. Energy transition

H.1 Overview

The development of renewable energy is stagnating in Moldova. The country exceeded its 17% target for the share of renewable energy in the gross final energy consumption by 2020 due to a revision of biomass data and increasing the use of biomass in the heating sector. However, additional efforts have been implemented to increase the share of renewable energy in the electricity and transport sectors. Moldova's total renewable energy capacity was 110.46MW in January 2022 and 149MW as of July 2022.[83] This capacity is expected to increase in light of the 'explosion' in the prices of conventional fuel.

H.2 Renewable fuels

The regulatory basis regarding the use of hydrogen, as a renewable fuel, is general. As Moldova is a Contracting Party to the Energy Community, it has a continuous obligation to implement the energy *acquis* in force. Therefore, improvement of the legislative framework is expected; to date, the GoM has adopted one decision, ie Decision no. 270/2020, on approval of the Regulation on determination of the final consumption of energy from RES in transport activity.

H.3 Carbon capture and storage

Carbon capture and storage technology has not been developed in Moldova. However, considering the concrete circumstances, the Reduced Emissions Strategy and the 2030 Energy Strategy provide two possibilities for carbon capture and storage technology for the period 2021-2030:

- no development: due to a lack of anticipated results or places of storage; or
- limited development.

H.4 Oil and gas platform electrification

Oil and gas platform electrification is not applicable to Moldova.

H.5 Industrial hubs

Moldova has no industrial hubs (ie, regions where specific types of business are clustered). There are, however, ten industrial parks (located in Chisinau, Balti, Cimislia, Edinet, Comrat, Cahul, Straseni Drochia). Under the Industrial Parks Law,[84] industrial parks constitute delimited territories with technical and production infrastructure, in which economic activities are conducted; mainly industrial production, supply of services, scientific research and/or technological development in a regime of specific facilities in order to develop the human and material potential of a region.

Industrial parks can be created at the initiative of central public authorities, local public authorities, state/municipal enterprises and private companies.

H.6 Smart cities

Although there are certain discussions on measures to be taken for the purpose of transforming the Chisinau Municipality (the capital of Moldova) into a smart city, one cannot say that there are concrete steps in this respect, since the mere concept of smart city is not regulated.

I. Environmental, social and governance (ESG)

ESG aspects potentially affecting the investment in the energy sector:

- certain environmental aspects (eg use of renewable energy, waste management, etc) remain underregulated, although we must admit that the Moldovan authorities are progressing in this respect;
- the Moldovan legislation is protective towards employees regarding the relationship between employers and the employees; and
- starting 1 March 2019, the Civil Code of Moldova (including corporate governance) was significantly amended to transform it in one of the most advanced and modern collection of civil principles and norms in the region.

Endnotes

1. Articles 10(1) and 12(2) Electricity Law.
2. Article 12(9) Electricity Law.
3. See www.anre.md/registrul-de-licentiere-3-134.
4. Article 46 Electricity Law.
5. Article 19(7) Electricity Law.
6. Article 26(2) Electricity Law.
7. Article 40(1) Electricity Law.
8. Article 86 Electricity Law.
9. Article 87 Electricity Law.
10. Point 5 Regulation 286/2018.
11. Point 15 Regulation 286/2018.
12. Article 88 Electricity Law.
13. Article 14 Electricity Law.
14. Article 11 Electricity Law.
15. Article 55(9) Electricity Law.
16. Plan on Development of the Electricity Transmission Network in the period 2018-2027 (by I.S. Moldelectrica).
17. Plan on Development of the Electricity Transmission Network in the period 2018-2027 (by I.S. Moldelectrica).
18. ANRE Report on the results of monitoring of the petroleum products market of the Republic of Moldova for 2021.
19. Article 12 Petroleum Products Market Law.
20. Article 7 Petroleum Products Market Law.
21. ANRE Report of activity for 2021.
22. ANRE Report of activity for 2017.
23. See www.moldovatransgaz.md/ro/activities/transmission/map.
24. See www.app.gov.md/ro/content/comunicat-1.
25. See www.mold-street.com/?go=news&n=15119.
26. See www.rfi.ro/economie-151061-romania-inceput-exportul-de-gaze-catre-republica-moldova-prin-conducta-iasi-ungheni.
27. Article 12(2) Natural Gas Law.
28. Article 12(9) Natural Gas Law.
29. See www.anre.md/registrul-de-licentiere-3-261.
30. Article 55(1) Natural Gas Law.
31. Article 55(7) Natural Gas Law.
32. Article 55(5) Natural Gas Law.
33. Article 58 Natural Gas Law.
34. Article 58(4) Natural Gas Law.
35. Article 58(6) Natural Gas Law.
36. Article 98 Electricity Law.
37. Article 99 Electricity Law.
38. Point 5 Regulation 286/2018.
39. Point 15 Regulation 286/2018.
40. Article 100 Natural Gas Law.
41. Article 14(1) Petroleum Products Market Law.
42. Article 19 Petroleum Products Market Law.

43. Article 20(2) Petroleum Products Market Law.
44. Article 20(3) Petroleum Products Market Law.
45. Article 14(2)-(4) Petroleum Products Market Law.
46. Articles 14(2) and 14(3) Natural Gas Law.
47. Article 36 Natural Gas Law.
48. Article 11 Natural Gas Law.
49. Article 69(9) Natural Gas Law.
50. See www.moldovatransgaz.md/ro/technical-data/map.
51. Article 75(1) Electricity Law.
52. Article 78(3) Electricity Law.
53. Article 79(4) Electricity Law.
54. Article 80(2) Electricity Law.
55. Articles 80(3) and 80(4) Electricity Law.
56. Article 80(5) Electricity Law.
57. Article 77(1) Electricity Law.
58. Article 77(3) Electricity Law.
59. he Dutch Title Transfer Facility (front month) price (published with the Argus European Natural Gas review).
60. Article 92(1) Natural Gas Law.
61. Article 94(3) Natural Gas Law.
62. Article 95 Natural Gas Law.
63. The Renewables Law entered into force on 25 March 2018.
64. Article 6(1) Renewables Law.
65. See www.aee.md/ro/page/surse-de-energie-regenerabila.
66. ANRE Report of activity for 2021.
67. See www.anre.md/2022-3-395.
68. See www.anre.md/registrul-producatorilor-eligibili-3-213.
69. See www.midr.gov.md/files/shares/Concept_Strategia_Enenergetica__act__.pdf.
70. Article 21 Renewable Law.
71. Article 28 Renewables Law.
72. Article 34 Renewables Law.
73. Article 28(7) Renewables Law.
74. Article 32 Renewables Law.
75. ANRE Decision no. 376 dated 28 September 2017 "on approval of the Regulation on the guarantees of origin for electricity produced from renewable sources".
76. Land Code no. 828 dated 25 December 1991.
77. Article 36(d) Land Code.
78. Article 83 Land Code.
79. Points 42- 50 Decision no. 690/2018.
80. Article 6(1) Renewables Law.
81. See www.aee.md/ro/page/surse-de-energie-regenerabila.
82. Article 29(3) Renewables Law.
83. See www.aee.md/ro/page/surse-de-energie-regenerabila.
84. Article 6(1) Industrial Parks Law.

Energy law in Montenegro

Recent developments in the Montenegrin energy market

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Legislation development

In 2020, Amendments to the Energy Act[1] were adopted stipulating the adoption of a new National Energy and Climate Plan ("NECP"), which will further define the transition towards green energy and the use of renewable energy sources ("RES"). The Amendments to the Energy Act also provide for digitalisation, setting the basis for registers and records to be available in digital form. For example, licence and energy permit registers have already been made available in electronic form.

Legislation regarding strategic environmental assessments ("SEA"), and its accompanying secondary legislation, is consistent with the Strategic Environmental Assessment Directive[2], however, the SEA procedure for the draft NECP was not initiated despite the fact that the draft plan is already at an advanced stage of preparation, and scenarios have been developed. This lack of action may have a detrimental effect on the quality of the SEA process for the draft NECP, as the SEA procedure is intended to be carried out during the preparation of the plan itself.

At the beginning of 2022, Montenegro adopted the Act on Surveillance of the Wholesale Electricity and Natural Gas Market[3] implementing the Regulation on Wholesale Energy Market Integrity and Transparency ("REMIT"). The new law empowers the Energy and Water Regulatory Agency of Montenegro ("REGAGEN") to monitor energy markets and investigate market abuse, thus ensuring that energy prices are not manipulated.

Montenegro is reforming its energy and renewable energy legislative framework and, as at April 2023, the draft of the new Renewable Energy Law ("RES Act") is currently being prepared. The new RES legal framework aims to enable transition from the guaranteed offtake (feed-in tariffs) for large-scale RES to market-based support under the market premium scheme. Adoption of the new RES Act is expected in the second quarter of 2023, following which the implementing secondary legislation shall be adopted to unlock new support measures.

Montenegro also recently held a public consultation on a proposed new Law on the Supply of Petroleum Products in the Event of Supply Disruptions[4]. The draft Law outlines that the Ministry in charge of energy will oversee the establishment of one-third of the emergency oil reserves in physical form within Montenegro's territory. The remaining two-thirds of the reserves will be established by the oil-importing companies operating in Montenegro. Market operators will have the flexibility to meet their obligations by establishing reserves physically or through tickets, or with a combination of both.

The Energy Community Secretariat actively cooperates with the Ministry of Capital Investments of Montenegro ("Ministry of Capital Investments") and REGAGEN to ensure that energy sector reforms work to the benefit of consumers and contribute to the smooth operation of the pan-European energy market.

In December 2022, the Energy Community adopted targets for 2030 to: (i) reduce primary and final electricity consumption; (ii) accelerate the uptake of renewables; and (iii) reduce greenhouse gas emissions and to achieve climate neutrality by 2050. Further, Energy Community also adopted a new electricity package[5] that will enable full market integration of the Energy Community's contracting parties, including Montenegro, into the European market based on the principle of reciprocity. As a European Community's contracting party, Montenegro has made a binding commitment to adopt the core EU energy legislation and in that regard by the end of 2023 Montenegro is obliged to transpose the new electricity package into its legislation. The Ministry of Capital Investments is actively working on transposing the electricity package by way of drafting and adopting a new Energy Act, which will be synchronised with the currently drafted RES Act.

Below is a brief summary of the Energy Community's *acquis* to be transposed:

NO	ACT	IMPLEMENTATION DEADLINE
	Electricity	
1.	Regulation (EU) 2019/942 on establishing European Union Agency for the Cooperation of Energy Regulators	1 January 2024
2.	Regulation (EU) 2019/943 on the internal market of electricity	1 January 2024
3.	Directive (EU) 2019/944 on common rules for the internal market of electricity	31 December 2023
4.	Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation	1 January 2024
5.	Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management	1 January 2024
6.	Commission Regulation (EU) 2017/2195 establishing a guideline on electricity balancing	1 January 2024
7.	Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation	1 January 2024
8.	Commission Regulation (EU) 2017/2196 establishing a network code on electricity emergency and restoration	1 January 2024
	Security of supply	
9.	Regulation (EU) 2019/941 on risk-preparedness in the electricity sector	1 January 2024
10.	Regulation (EU) 2017/1938 concerning measures to safeguard the security of gas supply	31 December 2022
	Cross-cutting	
11.	Regulation (EU) 2020/1044 supplementing Regulation (EU) 2018/1999 of the European Parliament and of the Council with regard to values for global warming potentials and the inventory guidelines and with regard to the Union inventory system	31 December 2022
12.	Regulation (EU) 2020/1208 on structure, format, submission processes and review of information reported by Member States pursuant to Regulation (EU) 2018/1999	31 December 2022
	Climate	
13.	Regulation (EU) 2018/1999 on the Governance of the Energy Union and Climate Action	31 December 2022

Energy related issues

Change of ownership structure of EPCG

Elektroprivreda Crne Gore ("EPCG") national energy company, as a dominant player in the Montenegrin electricity market, together with the Government of Montenegro ("Government") took over the remaining shares in EPCG from A2A S.p.A. ("A2A") amounting to 18.6%. A2A S.p.A activated the put option in 2017 to sell 40% of its shares in EPCG. Currently, EPCG is disposing of 10% of its shares. The initial plan was to do so through public calls allowing for one big investor to take over the entire 10%. However, after two unsuccessful public calls, EPCG listed its shares on the stock exchange in September 2022. Finally, on 22 September 2022, the Government of Montenegro adopted a decision on the purchase of 10% of shares in EPCG.

TPP Pljevlja

In recent years, there has been a push to transition away from coal and towards RES in Montenegro, and the Government has set a goal of achieving carbon neutrality by 2050. However, the operators of the Thermo Power Plant ("TPP") Pljevlja, including EPCG, have proposed to upgrade the plant, which would involve construction of a new unit to replace two of the existing units and extending the plant's life until 2070.

Planned reconstruction of the TPP Pljevlja is in its final phases with expectations that the heating can start at full capacity by 2024/2025.

Currently, the operating first unit of TPP Pljevlja, a 300MW lignite fired TPP, is not in line with the prescribed emissions' limits under the LCP Directive (as defined below). For this reason, EPCG previously engaged in developing a new (second) unit of TPP Pljevlja, with a capacity in the range of 200MW to 300MW and energy efficiency of at least 38%. The Consortium led by China's Donfang Electric International Corp., chosen in 2019 to lead the reconstruction, predict that TPP Pljevlja will boost efficiency to 31% and cut emissions to the required levels, and thereby will be brought in line with the EU rules.

Notable energy related cases

Case ECS 15/21

Case ECS 15/21 ("Case") concerns a violation of the provisions outlined in the Large Combustion Plants Directive ("LCP Directive")[6] in Montenegro. Namely, TPP Pljevlja was granted exemption from the LCP Directive by the Energy Community, now operating an additional 20,000 hours until 2024.

Specifically, the Energy Community's Secretariat ("Secretariat") has determined that TPP Pljevlja, which is the sole large combustion plant in Montenegro, did not adhere to the opt-out guidelines set out in Article 4(4) of the LCP Directive. Despite reaching its maximum operating hours of 20,000 by the end of 2020, the plant did not follow the more rigorous standards outlined in the Industrial Emissions Directive, nor did it halt its operations as required by Energy Community law.

On 9 February 2023, the Secretariat submitted a Reasoned Opinion[7] in the case against Montenegro for its failure to comply with the limited lifetime derogation obligations regarding TPP Pljevlja. Having considered the reply of the Ministry of Capital Investment to the Opening Letter, the Secretariat considered that the arguments provided did not change the findings of the Secretariat in the Opening Letter.

Montenegro is now requested to rectify the identified issues of non-compliance within a time limit of two months.

Major projects

Subsea power transmission cable between Italy and Montenegro

A project to build a subsea power transmission cable (500kVDC 1,000MW) between Italy and Montenegro has been completed. In 2010, CGES, the Montenegrin transmission system operator ("TSO"), entered into an agreement with the Italian company Terna S.p.A. on installing a high voltage, 415km long, DC submarine cable under the Adriatic Sea. The cable connects the two coasts from the Italian city of Pescara to the Montenegro city of Tivat. This project is part of the 'Trans-Balkan corridor', making Montenegro the energy hub of strategic importance for connection to the electricity markets of Southwestern and Southeastern European countries.

The TSO has concluded the agreements on construction of the Lastva power station with Siemens (Austria) and construction of a 400kV Lastva-Cevo transmission line with Iberdrola (Spain). Energoinvest (Bosnia and Herzegovina) has been awarded the contract for the construction of the 400kV Cevo-Pljevlja transmission line. The entire project is estimated to be worth about €750 million.

Moreover, the Government of Montenegro, the TSO and Terna S.p.A. have further joint investment plans to construct 400kV transmission lines from Montenegro to Serbia and/or Bosnia and Herzegovina, creating a grid ring across Montenegro that would optimise the Montenegrin transmission system. In that regard, the production of the detailed spatial plan for the Pljevlja 2-Bajina Bašta corridor 400kV line to Serbia has been completed for part of the line on Montenegrin territory.

Floating solar power plant on Lake Slano

In June 2021, EPCG announced that it plans to build a floating solar power plant on Lake Slano ("Slano"). This power plant would be the first of its kind in the region.

The Slano reservoir, owned by the EPCG spans about nine square kilometres ("km") and, according to EPCG, the development of the solar panels would not entail resolving any ownership issues. Further, Slano represents a great potential for renewable energy development in Montenegro, particularly given that the country does not have large land areas suitable for ground-mounted solar power plants. However, since 2021, the project has been in its initial phase, although EPCG has stated that it has not been abandoned.

Gasification

Montenegro adopted the Gasification Master Plan in July 2017, which determined that for the complete gasification of Montenegro a pipeline with a length of 570km about €300 million to €400 million would be needed.

The Gasification Master Plan envisages that the Ionian Adriatic Pipeline would go through Croatia, Bosnia and Herzegovina, Montenegro and Albania. The project has been recognised by the Energy Community and the European Network of Transmission System Operators for Gas ("ENTSOG"), as an important factor in the European gas infrastructure. The Gasification Master Plan considered three possible routes. However, the Government subsequently decid-ed to include a 94km long pipeline project with six supporting plants, valued at €118 million and with a 3.5 year construction period, on the list of priority infrastructure projects. Moreover, there are several Serbian companies interested in realising the potential of the Port of Bar as a basis for the distribution of liquefied gas.

Development in the renewable energy sector

Hydropower plants

Montenegro has great hydro potential, evident in the fact that 38 Small Hydropower Plants ("SHPPs") were developed up to the end of 2021. Montenegro concluded 12 new concession agreements for construction of SHPPs in 2017-2018. Development of RES projects in Montenegro is mostly governed by the award of concession agreements to the developers (for granting both the feed-in tariffs ("FiTs") and the required land for the power plants).

There are two big Hydropower Plants in Montenegro, ie HPP Perućica and HPP Piva. However, in 2022, a concession was awarded regarding HPP Komrnica. The planned power of HPP Komarnica is expected to have capacity of about 168MW, and annual production of around 232GWh. The whole project is worth around €270 million, financed 51% from Montenegro, ie, EPCG and 49% from Serbia, ie, EPS. Its construction is set out under the Energy Development Strategy of Montenegro to 2030 and the Montenegrin Spatial Plan.

Wind power projects

The wind power projects ("WPP") currently in operation in Montenegro are:

- WPP Krnovo, with installed capacity of 72MW and planned annual generation of about 160GWh, a project realised by the consortium of Austrian Ivicom Consulting and the French Akuo Energy. WPP Krnovo has been constructed and the plant commenced generation in November 2017. The plant is currently owned and operated by Masdar, ie the Abu Dhabi Future Energy Company, UAE.
- WPP Možura, with installed capacity of 46MW and planned annual generation of about 100GWh, a project realised by Enemalta plc and Shangai Electricity Power.

There are plans for EPCG to construct another WPP, ie Gvozd. WPP Gvozd is planned to have an installed capacity of 54,6MW and is expected to be put into operation in 2024. The estimated value of the project is €58 million. The start of the construction was planned for the spring of 2022, however, construction was delayed due to the COVID 19 pandemic.

A long-term lease agreement has also been concluded between the Government and the Consortium of WPD AG, ie Vjetroelektrane Budva for the Brajići locality, for the construction of WPP Brajici with a capacity over 100,8MW. TA Government decision has been reached regarding the urban planning for the municipalities of Budva and Bar. These projects significantly influence the share of RES in the overall volume of electricity generated.

Solar power projects

Montenegro is rich in solar radiation, specifically the southern part of the country. There is also a growing interest in renting state-owned land for construction of on-ground installed solar power plants. In these instances, when an investor is interested in the construction of a photovoltaic ("PV") power plant in a certain area, a public tender for a 30-year lease of state-owned land may be executed.

Briska Gora is a new project and the first large-scale solar power project in Montenegro. A consortium of EPCG and Fortum (as EPCG's contractor) has been selected as the winning bidder for the project. The capacity of the plant, which will be constructed in two phases and finished within three years of commencement of construction, is 200MW, with accompanying infrastructure and the connection to the system. In the first 18 months 50MW will be constructed, and in the second phase the remaining 150MW will be constructed. In 2021, the Government decision prescribed a deadline for the creation of the detailed urban spatial plan in Ulcinj, which will allow for further development of this solar power project.

At the end of 2022, EPCG approved the launch of Solari 5.000+, a project which will offer the installation of 5,000 rooftop solar power plants to households, legal entities and residential communities. The Solari 5.000+ project will enable the addition of 70MW to total solar power capacity, valued at €70 million. A subsidy of 20% of the investment is available for eligible consumers who meet the public call conditions. Before Solari 5.000+, the Solari 3,000+ and Solari 500+ projects sparked a huge response as more than 14,000 consumers have applied for the installation of PV systems on their rooftops.

With the Solari+ projects, EPCG provides solar panels and other equipment for PV facilities and installs them for consumers selected from the public call. Consumers repay the investment in the form of a loan over a period of five to seven years.[8]

Incentive price system

The RES Act will likely account for the specific circumstances in Montenegro (in particular, the lack of an operational day-ahead market) which are likely to require 'transitional arrangements' to accompany the introduction of a feed-in-premiums ("FiP") in the short-term.

The transitional regime could take one of the following two forms, which are yet to be determined in the RES Act: (i) FiT with a conversion clause to FiP: In this case, generators would initially conclude a 'traditional' FiP with an offtaker of the energy produced (ideally the entity that also acts as offtaker for the FT for small plants). The FiP would then automatically convert to a two-way contract for difference, once certain 'market readiness criteria' have been fulfilled. Bankability aspects of such arrangement will be taken into consideration; and (ii) the FiP with a reference price whose definition ('underlying market') changes over time. In this case, a foreign price index sourced from a well-established, liquid exchange such as the South East European Power Exchange (SEEPEX a.d. Beograd) ("SEEPEX") would initially serve as the reference price for the Montenegrin FiP agreement. The selection of price index needs to be such as to enable Montenegrin generators to access such price with no major hurdles and to forecast market access costs with a reasonable degree of certainty.

EBRD support

The European Bank for Reconstruction and Development ("EBRD") is helping the Ministry of Capital Investments implement projects with dedicated technical assistance, financed by grants from the EBRD, the Austrian Federal Ministry of Finance and Italy through the Central European Initiative. EBRD combines investment in RES with policy engagement to increase renewable energy capacity and decarbonise the energy sector. Further, EBRD's priority is to invest in low carbon and climate resilient municipal infrastructure and related services, including water and waster water, waste management and district heating. In that regard, EBRD is currently cooperating with Montenegro in adopting the RES Act.

EBRD has previously financed EPCG in the installation of smart meters throughout the power distribution grid for domestic consumers. This project resulted in Montenegro becoming a regional leader in smart meter deployment and the first EBRD economy to meet the EU target for smart meter coverage.

Montenegro power exchange

The Montenegro Power Exchange ("MEPX") became operational in 2021. MEPX, EPEX SPOT, and BSP SouthPool (Slovenian power exchange) signed a service agreement with the aim of developing a transparent and efficient power market. The power market will enable Montenegro to couple with neighbouring countries and operate in accordance with the European Internal Energy Market. The goal for the power exchange is to implement market coupling with at least one neighbouring country, after the introduction of the day-ahead market operation. This will provide for an opportunity for energy trading. Currently, the power exchange is used to cover losses on the market, but the ultimate plan is to create a trading market in line with European standards further allowing for physical futures market. Trading through MEPX is currently carried out only for procurement of losses on the transmission and distribution system, with the official launch of the local day-ahead market in Montenegro is expected in 2023.

Clean energy package

Considering that Montenegro is in the process of joining the EU, Montenegro is obliged to harmonise its laws with the EU *acquis*, and Montenegrin legislation is at the moment predominantly aligned with the current *acquis* regarding energy sector.

Montenegro intends to also implement principles of the Clean Energy Package and is already depicted as a frontrunner in the Energy Community regarding many of the areas covered by the package. In order for Montenegro to improve energy efficiency, several incentives have been introduced. Green financing is currently conducted by EBRD in partnership with CKB Bank (Commercial bank of Montenegro), as well as Alter Modus, a microcredit institution. The Green Economy Financing Facility was launched in Montenegro in 2021, whereby EBRD partnered with CKB Bank to provide incentives of up to 20% to households that install green technologies, such as solar thermal water heaters, or solar PV installations. Alter Modus initiated the Green for Growth Fund in 2019 investing in green energy projects or refinancing local institutions to target reduction in energy use and CO_2 emissions. This fund is mostly used for improving thermal performance of buildings through roof and wall insulation and replacement of windows and doors.

Additionally, the 'cap and trade' system has been introduced regarding CO_2 emissions, which means that energy producers who emit CO_2 have a quota limiting such emissions, and they are able to trade the difference between quota and actual emissions. A decree has been introduced which regulates the manner of such trade, as well as the allocation of free emission credits. If a producer surpasses the quota, it incurs a mandatory taxation of €24 for each additional emitted tonne.

There are a number of incentives regarding the use of electric vehicles, such as loans for the purchase of such vehicles. The Government also plans on introducing the use of renewable fuels in the near future, with a pilot being conducted on public transport vehicles using specified bus lines.

Endnotes

1. Official Gazette of Montenegro, Nos. 5/2016, 51/2017, 82/2020 and 29/2022.
2. Directive 2001/42/EC.
3. Official Gazette of Montenegro, No. 1/2022.
4. See www.gov.me/en/documents/524569d0-fd7d-423a-86e2-eafc5493098e.
5. The goal of the newly adopted electricity package is to support the large-scale integration of renewables and coal phase out.
6. LCP Directive took effect in the Energy Community on 1 January 2018. The directive requires operators of large combustion plants to significantly reduce the emissions of listed air pollutants. Opt-out is a time-barred implementation alternative to com-ply with the provisions of the directive.
7. A Reasoned Opinion is the second step in a dispute settlement procedure initiated by the Secretariat under Article 90 of the Energy Community Treaty. Depending on the reply by Montenegro, the Secretariat may submit the case to the Ministerial Council for a decision on Montenegro's compliance with Energy Community law.
8. When customers pay off the debt, their monthly invoices should become much lower than they were before the installation of the solar panels.

Overview of the legal and regulatory framework in Montenegro

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Montenegro is mostly liberalised through unbundling of the transmission system operator ("TSO") and distribution system operator ("DSO"). However, Montenegro's wholesale bilateral market is small and highly concentrated with one dominant producer and trade, whereas the day-ahead market is not yet operational. Currently, the power exchange company Montenegrin Power Exchange ("MEPX") is in the process of establishing a day-ahead trading, clearing, and settlement platform for Montenegro's electricity market. The platform is not yet operational and the adoption of day-ahead market rules is pending.

Montenegro has a total installed capacity of about 870MW, with most of the generation coming from hydropower plants, followed by thermal power plants and then wind power. Montenegro is connected to the regional electricity market through interconnections with neighbouring countries such as Serbia, Bosna and Herzegovina, and Albania.

Key market players

The key players in Montenegro's electricity market are:

- Elektroprivreda Crne Gore ad Nikšić ("EPCG"), which is the national electricity utility, owned by the State of Montenegro (98.5430%) and several minority shareholders;
- Crnogorski eletrkodistributivni system ("CEDIS"), which is Montenegro's DSO founded by and in the sole ownership of EPCG;
- Crnogorski elektroprenosni system ("CGES"),which is the Montenegrin TSO jointly held by the State (55%), Italian company Terna - Rete Elettrica Nazionale S.p.A. (22%), and Elektromreža Srbije ad ("EMS"), Serbian TSO (10%) and several minority shareholders; and
- Crnogorski operater tržišta električne energije ("COTEE"), which is the electricity market operator and has the Government of Montenegro ("Government") as its sole shareholder.

Previously, an Italian company, A2A S.p.A., held shares in EPCG amounting to 18.6% which EPCG and the Government took back from A2A S.p.A. using an available buyback scheme.

EPCG is also engaged in distribution and supply activities through CEDIS, performing the tasks of a public supplier and the supplier of last resort. The conditions for these activities are set out under the Energy Act (*Zakon o energetici*) and, once these conditions are fulfilled, these activities are assigned to a supplier in a competitive procedure initiated by the Ministry of Capital Investments of Montenegro (*Ministarstvo kapitalnih investicija*) ("Ministry of Capital Investments"). EPCG has been selected by the Government as the supplier of last resort and supplier of vulnerable customers.

Regulatory authorities

The Regulatory powers in the Montenegro electricity market belong to:

- The Government, which together with the Montenegrin Parliament, is the key authority regulating the energy sector in Montenegro;
- Ministry of Capital Investments, which is in charge of activities related to electricity, and energy policy and energy efficiency matters; tthe Directorate for Energy and Energy Efficiency within the Ministry of Capital Investments (*Direktorat za energetiku i energetsku efikasnost*) ("Directorate"), conducts activities regarding the preparation and assessment of investment projects in Montenegro, as well as managing development policy, monitoring sector activities and taking measures in the field of energy and energy efficiency;
- Energy and Water Regulatory Agency of Montenegro (*Regulatorna agencija za energetiku i komunalne djelatnosti Crne Gore*) ("REGAGEN"), which regulates the energy market by overseeing the generation, transmission, distribution, market operation and supply activities[2].

Legal framework

The primary piece of legislation is the amended Energy Act, which entered into force in August 2020, and which transposes key provisions of the Third Energy Package in order to align the Montenegrin legal framework with EU *acquis*, as required under negotiation chapter no. 15[3].

In addition, in January 2022, the Act on Surveillance of the Wholesale Electricity and Natural Gas Market[4], transposing Regulation 1227/2011[5] on the integrity and transparency of wholesale market into Montenegrin legislation, entered into force. This Act prescribes several obligations of wholesale market participants, while REGAGEN has been assigned a supervisory role over the wholesale market. After the adoption of this law, REGAGEN adopted a set of by-laws further harmonising the Montenegrin market with the Energy Community market. In cooperation with the Coordinated Auction Office in Southeast Europe ("SEE CAO"), REGAGEN established a record of participants in the wholesale market and Montenegro also became a participant in the activities of the working group within the Energy Community Regulatory Board.

The energy sector is further regulated by the Energy Act's by-laws including the following:

- Rulebook on licences for the performance of energy activities (*Pravila o licencama za obavljanje energetskih djelatnosti*)[6];
- Rules for Functioning of Electricity Distribution System (*Pravila za funkcionisanje distributivnog sistema električne energije*)[7]; and
- Rules for Functioning of Electricity Transmission System (*Pravila za funkcionisanje prenosnog sistema električne energije*)[8].

Various decrees have also been established to determine the prices for connection to transmission and distribution grids and a set of secondary legislation regulating renewable energy sources ("RES") including:

- Decree on the conditions and methods of issuing, transferring, using and revoking origin guarantees for electricity produced from RES and high-efficiency cogeneration (*Uredba o bližim uslovima i načinu izdavanja, prenošenja, iskorišćenja i povlačenja garancije porijekla električne energije proizvedene iz obnovljivih izvora energije i visokoefikasne kogeneracije*)[9];
- Decree on method of acquiring the status of privileged producer of electricity (*Uredba o načinu sticanja I ostvarivanja prava povlašćenog proizvođača električne energije*)[10]; and
- Decree on the detailed conditions and methods of issuing, transferring, using, and revoking guarantees of origin for electricity produced from RES and high-efficiency cogeneration (*Uredba o bližim uslovima i načinu izdavanja, prenošenja, iskorišćenja i povlačenja garancije porijekla električne energije proizvedene iz obnovljivih izvora energije i visokoefikasne kogeneracije*)[11].

The Act on Efficient Energy Consumption (*Zakon o efikasnom korišćenju energije*)[12] with its pertaining by-laws, represents another notable part of legislation in the electricity legal framework. Amendments to the Act on Efficient Energy Consumption have introduced, amongst other things, an information monitoring and energy efficiency verification system.

Legislation governing the electricity sector is generally harmonised with the Third Energy Package as well as EU legislation, among others, including:

- Third Electricity Directive[13];
- Transparency Regulation[14];
- Third Gas Directive[15]; and
- ACER Regulation[16].

Montenegro transposed the Third Energy Package in 2015, following almost a year of delay. Compliance with the energy package was accomplished by the adoption of the Energy Act in 2016, which has transposed the key principles set out in the Third Energy Package.

A.2 Third party access regime

In accordance with the applicable laws, and on the basis of the principles of transparency and non-discrimination, the electricity grid operators (*CEDIS and CGES*) allow third party access to the system. Therefore, subject to fulfilling technical requirements for connection to the system, any foreign or local entity can request access from CEDIS and CGES. Third party access can only be denied if provision of the public service may be endangered. If access to the system has been denied, the applicant can file an appeal with REGAGEN.

Fees, terms and requirements for access are further regulated by the relevant grid codes of the operators in line with the basic principles prescribed under the Energy Act. Methodologies for calculation of grid tariffs adopted by REGAGEN must be applied by the operators.

In order to ease market entry and ensure that potential entrants are well-informed, REGAGEN published guidelines on its website listing steps that such entrants need to take in order to enter into the market.

A.3 Market design

EPCG continues to be the dominant producer and trader of electricity in the Montenegrin wholesale market. Transmission activities are performed by CGES, and the market is operated by COTEE. The Montenegrin electricity sector is in principle governed by the amended Energy Act. In the Montenegrin energy sector, there are 21 licenced stakeholders, 17 of which engage in market activities, and three of which engage in regulatory activities.

In order to further expand the market, since 2018 there has been an ongoing project to link the markets of Albania, Italy, Montenegro and Serbia (the AIMS project), and in the realisation of this project regulatory bodies, stock markets and TSOs have been included.

In the retail market in 2021, six legal entities had licences for the supply of electricity issued by REGAGEN, of which only one, EPCG, has been active. The current retail prices are based on the Energy Act limits, which are scheduled to expire in 2023. After that, the existing legal framework dictates that retail prices can be freely determined.

A.4 Tariff regulation

Tariff regulation is introduced for a period of three years and approved ex-ante by REGAGEN. The latest set of such tariffs was determined at the end of 2022 and will be applicable for the subsequent three years. These tariffs are established for use of the distribution and transmission systems, as well as the permitted income of system operators.

REGAGEN annually adopts the following methodologies applicable to this tariff regulation: (i) Methodology for Determining Prices, Terms and Conditions for Connection to Distribution System; (ii) Methodology for Determining Prices, Periods and Conditions for Providing Ancillary Services and Balancing Services of Transmission System; (iii) Methodology for Determining the Regulatory Allowed Income and Fee for Electricity Market Operator Work; (iv) Methodology for Determining Regulatory Allowed Income and Prices for Using the Power Distribution System; (v) Methodology for Determining Regulatory Allowed Income and Prices for Using Electricity Transmission System; (vi) Rules for Functioning of Electricity Distribution System; and (vii) Rules for Functioning of Electricity Transmission System.

A.5 Market entry

Licensing regime

The licensing regime in Montenegro is implemented and overseen by REGAGEN, in accordance with the rules set under the Energy Act and its by-laws. Rules on licences for conducting energy activities were established in 2021 (*Pravila o licencama za obavljanje energetskih djelatnosti*)[17] . An energy licence for the performance of energy activity is typically issued for a period of up to ten years. An energy licence is not required for the generation of electricity in power plants with a capacity of less than 1MW. Foreign legal entities may also obtain an energy licence for certain energy activities in Montenegro (wholesale electricity trading), provided that they are registered and licensed for performing the energy activities in at least one EU or Energy Community's contracting party. Such provisions make market participation in Montenegro without a local presence significantly easier.

An energy permit, ie the Ministry's prior approval for new generation capacity, is required for the construction of energy facilities with less than 1MW of the installed capacity.

Market entry is not subject to any strict or comprehensive procedures or requirements. However, a number of basic requirements set by the Energy Act must be met, which vary depending on the type of energy activity being carried out. These mostly involve local presence (incorporation of local subsidiary/branch), acquiring the relevant energy permits and licences (depending on the activity to be performed), conclusion of required agreements (eg, power purchase agreements, grid connection/access agreements). The main barrier is that only local companies are eligible to participate in the retail Montenegrin energy market. A new entrant must therefore be duly registered and incorporated in Montenegro, and a foreign entity may only operate in the Montenegro energy market through a local subsidiary with respect to retail activities.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The following services are considered public services in the Montenegro energy sector pursuant to the Energy Act:

- electricity transmission;
- electricity distribution;
- supply of electricity or gas only in cases of supply of last resort or supply of vulnerable customers;
- operation of the electricity market;
- storage of natural gas;
- natural gas transmission;
- natural gas distribution;
- operation of LNG facilities;
- generation of heat for district heating and/or cooling (*sistem daljinskog grejanja*);
- distribution of heat for district heating and/or cooling; and
- supply of heat for district heating and/or cooling.

Pursuant to the Energy Act, these energy related public services are provided at regulated prices which are determined and prescribed by REGAGEN.

Smart metering

In 2010, Montenegro began modernising its electricity network by developing a project financed by the European Bank for Reconstruction and Development ("EBRD"). The project involves modernising the distribution measuring system by replacing existing electricity meters with newest generation electricity meters. The project began with the installation of modern smart electricity meters throughout the grid. The third phase of the project was completed in December 2020, and, as of April 2023, 81.5% of consumers on the distribution grid are covered with remote measurement and management system (338,000 meters). CEDIS has signed the agreement for expansion of the third phase with the Mezon-Regicom consortium and has started the installation of an additional 20,000 smart meters, coverage of which will reach about 97%, which is higher percentage than most countries in Europe.

Electric vehicles

There are currently less than 500 electric vehicles registered in Montenegro. Since 2019, the United Nations Development Programme ("UNDP") and Ministry of Sustainable Development and Tourism of Montenegro ("Ministry of Sustainable Development and Tourism") have, within the project of developing low-carbon tourism, installed several public charging stations for these vehicles.

In 2021, the fund for environmental protection (*Fond za zaštitu životne sredine*) published a public invitation to natural and legal persons and entrepreneurs for the grant of subsidies for the purchase of electric and hybrid vehicles.

In 2022, this fund published the same public invitation, alongside another one aimed specifically at the use of such vehicles in the public sector. Natural persons can obtain a grant for the purchase of a single vehicle, while legal persons, entrepreneurs and the public sector can be subsidised for the purchase of two vehicles, with the maximum amount of grants available to the fund being €100,000.

These are the first steps which have been taken to incentivise the purchase of green vehicles for the purpose of environmental protection, energy efficiency and use of RES.

A.7 Cross-border interconnectors

Montenegro has 12 cross-border interconnections. These interconnections are with Serbia, Kosovo, Bosnia and Herzegovina, and Albania, ranging from 110kV up to 440kV capacity, as follows: (i) Serbia: two interconnectors of 220kV and one interconnector of 110kV; (ii) Kosovo: one interconnector of 440kV; (iii) Bosnia and Herzegovina: one interconnector of 400kV, two interconnectors of 220kV and two interconnectors of 110kV; (iv) Albania: one interconnector of 220kV and one interconnector over 400kV; and (v) Italy: subsea power transmission cable (initial capacity of the interconnection is 600 MW).

The subsea power transmission cable with Italy represents a new transit route, running 423 kilometres ("km") along the Adriatic seabed, connecting electricity systems of Italy, Montenegro, Serbia, Bosnia and Herzegovina and Romania. This cable is operated by Terna, the Italian electricity transmission system operator.

To date, CGES has operated the interconnectors. However, the Energy Act envisages that certified TSOs from other countries may perform electricity transmission activities through the interconnectors in Montenegro (without obtaining an energy licence), if: (i) the interconnector is part of public infrastructure; (ii) the owner of the interconnector enters into a connection agreement with CGES; and (iii) the foreign certified TSO does not disrupt competition, efficient electricity market functioning and the orderly functioning of the Montenegrin electricity system.

B. Oil and gas

B.1 Industry structure

Oil

Montenegro does not produce any significant amount of oil, and relies heavily on imports to meet its energy needs. The oil market in Montenegro is primarily driven by the demand for transportation fuels, such as gasoline and diesel, as well as heating oil for residential and commercial use. Most of the oil imports and distribution in Montenegro are carried out by international oil companies such as Hellenic Petroleum, ENI, and Lukoil, which operate through subsidiaries or partnerships with local players. However, there are local companies in Montenegro that are involved in the distribution of petroleum products.

Oil reserves and oil derivatives are intended to be regulated by the new Energy Act.[18] In line with the newly adopted Energy Development Strategy by 2030, a joint stock company will be established, and the relevant by-laws will be adopted in order to further regulate oil storage requirements.

Gas

The gas market in Montenegro is not as developed as gas sectors in other south-eastern European countries. The Montenegrin gas market is small, import-dependent, and underdeveloped. The country has no significant domestic production of natural gas, and therefore relies heavily on imports to meet its demand. The demand for natural gas in Montenegro is primarily driven by the industrial sector, as well as the use of natural gas for heating in households and commercial buildings. However, the overall consumption of natural gas in Montenegro is relatively low compared to other European countries.

Key market players

In line with the Decision on Determining Gas Transmission System Operator (*Odluka o određivanju operatora prenosnog sistema gasa*),[19] the Government has designated the company 'Montenegro Bonus' d.o.o. Cetinje as the gas TSO. This TSO was founded by the Government and was appointed by the Government as the future transmission system operator. Montenegro Bonus is not yet unbundled under the ownership unbundling model, as defined by the Energy Act.

Regulatory authorities

The regulatory powers in the Montenegrin gas sector belong to:

- the Government, which, together with the Montenegrin Parliament, is the main authority regulating the oil and gas sector in Montenegro;
- Ministry of Capital Investments which is in charge, among other things, of the development and regulation of Montenegro's oil and gas sector, working to promote investment, regulation, and support for both domestic and foreign companies operating in this field of industry; and
- REGAGEN, which is responsible for ensuring a natural gas market that is fair, competitive, and efficient, and that ultimately benefits both consumers and market participants. This is achieved through its duties of providing licensing and supervision of market participants, regulating natural gas tariffs, monitoring market activities, and protecting consumers.

Legal framework

The oil and gas sector in Montenegro is mainly covered by the Energy Act. The following essential laws are also applicable to the sector:

- Act on Mining (*Zakon o rudarstvu*);[20]
- Act on Cross-border Exchange of Electricity and Natural Gas (*Zakon o prekograničnoj razmjeni električne energije i prirodnog gasa*);[21]
- Act on Hydrocarbon Exploration and Exploitation (*Zakon o istraživanju i proizvodnji ugljovodonika*);[22] and
- Act on Spatial Planning and Construction of Buildings (*Zakon o prostornom planiranju i izgradnji objekata*).[23]

Implementation of EU gas directives

The unbundling and the certification requirements in the gas sector, prescribed under the Third Energy Package, were successfully transposed through the Energy Act. A recently adopted Act on the Cross-Border Exchange of Electricity and Natural Gas further regulates the Montenegrin gas sector and access to the transmission network, in line with the newly adopted hydrogen and market decarbonisation package. Montenegro has opted for the ownership unbundling model as the only unbundling model, however gas DSOs potentially serving less than 100,000 customers are exempted from unbundling requirements. Montenegro also transposed provisions of the Hydrocarbons Licencing Directive[24] through its legislation, while the implementation of the Safety of Offshore Operations Directive,[25] to date, is not complete.

B.2 Third party access regime to gas transportation networks

Montenegro still does not have access to the natural gas market. There are, however, contemplated gas-to-power projects in Montenegro and they are likely to rely on two different sources of gas:

- gas from the potential Ionian Adriatic Pipeline project, which would be the most significant gas transportation project in the country; and
- offshore hydrocarbon resources currently explored.

At the end of 2021, there were 34 entities storing oil derivatives and LNG; three of which were storing LNG. The total capacity for storing LNG is 3,144m^3, with Montenegro Bonus disposing of 1,100m^3.

B.3 LNG terminals and gas storage facilities

For more on LNG see section B.2.

B.4 Tarif regulation

Tariffs for access to the gas transmission and distribution grids are aligned with the Third Energy Package (separate tariff for each entry/exit point to/from the transmission grid). REGAGEN has adopted methodology regulating the permitted profit and prices for the use of system for storing gas in 2022, and the methodology for determining regulatory permitted profit and price for the use of LNG plant.

B.5 Market entry

Energy activities described in the Energy Act may be performed only on the basis of a licence, unless otherwise specified by the Act. The fulfilment of the conditions for issuing licences specified in the Energy Act is determined by REGAGEN. A licence is issued at the request of a company, legal entity or individual or entrepreneur:

- who is registered in the Central Register of Business Entities for the performance of energy activities for which a licence is issued;
- who owns or manages energy facilities, the means of transport and other devices, installations or plants necessary for the performance of energy activities that meet the conditions and requirements established by technical regulations, regulations on energy efficiency, regulations on fire and explosion protection, as well as regulations on environmental protection;
- who submits proof that employees of that company have passed an appropriate professional exam, ie evidence of a concluded contract with an individual who has passed an appropriate professional exam or a legal entity that has employees who have passed an appropriate professional exam for the performance of technical management, maintenance, exploitation and handling tasks for energy facilities;
- who holds free disposition of financial resources on its bank account;
- who has not had a licence for performing the energy activity in the last three years revoked; and
- whose members of the management body were not convicted of criminal offenses that make them unfit to perform their duties.

As part of its role as a regulatory agency under Act on Surveillance of the Wholesale Electricity and Natural Gas Market, REGAGEN made available a step-by-step process of obligations for wholesale market participants for electricity trading and the process of obtaining licences. For more see section A.5.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

N/A

Smart metering

CGES is obliged to establish an advanced system for measuring gas consumption during the development of the distribution system and the connection of consumers, while conducting studies and analytics on all costs and benefits for the market and customers. CGES is also obliged to ensure the coordinated operation of the system for smart metering with the application of appropriate standards and optimal professional solutions. The implementation of these obligations is supervised by REGAGEN.

B.7 Cross-border interconnectors

Currently, there are no cross-border natural gas interconnectors in Montenegro. However, the country has expressed interest in building a natural gas interconnector with neighbouring countries, particularly Serbia.

Montenegro does not produce any significant amount of oil/gas and relies heavily on imports to meet its energy needs. Montenegro imports natural gas mainly from Russia via a pipeline that passes through Ukraine, Romania and Hungary before entering Montenegro at the Horgoš border crossing with Serbia. The gas is then transported to Montenegro's sole gas-fired power plant, located in Pljevlja, as well as to other industrial consumers in the country. For more see section B.1.

In 2019, the governments of Serbia and Montenegro signed an agreement to conduct a feasibility study for a natural gas interconnector between the two countries. The proposed interconnector would enable natural gas to be transported from the existing pipeline in Serbia to Montenegro, improving the country's energy security and reducing its reliance on other fossil fuels.

C. Energy trading

C.1 Electricity trading

Electricity trading in Montenegro is controlled by a single dominant producer and trader, ie EPCG, making it a small and highly concentrated market. The day-ahead market is not yet operational as it is awaiting the establishment of a day-ahead trading, clearing and settlement platform by MEPX. In addition, day-ahead market rules need to be adopted, and the designation of a nominated electricity market operator is yet to be completed in accordance with the Energy Act. At present, MEPX only serves as an auction platform for the purchase of electricity to cover losses for the two network operators.

In addition to EPCG, electricity trading is also completed by COTEE, which is responsible for the organisation and management of the electricity trading market. COTEE is also the mandatory off-taker of all quantities of electricity generated from RES by privileged power producers.

C.2 Gas trading

There is no gas market in Montenegro, hence, there is no gas trading. Montenegro adopted the Gasification Master Plan of Montenegro in 2017, however, the plan remains silent on the issue of gas trading even though it recognises the need to adopt relevant secondary regulation in order to regulate the potential market.

D. Nuclear energy

Nuclear energy is not generated in Montenegro.

In accordance with Articles 17 and 19(2) of the Montenegrin Act on Protection Against Ionising Radiation and Radiation Safety (*Zakon o zaštiti od jonizujućeg zračenja i radijacionoj sigurnosti*),[26] development of nuclear facilities and import, processing, storage and disposal of nuclear waste of foreign origin on the territory of Montenegro is expressly prohibited.

A new law on protection against ionising radiation and radiation safety, to further align national legislation with international and EU standards, is expected to be adopted in the near future.

In relation to protection against radiation and nuclear security, Montenegro is a party to the following international legal instruments:

- Vienna Convention on Civil Liability for Nuclear Damage;
- Protocol to Amend the Vienna Convention on Civil Liability for Nuclear Damage;
- Convention on Early Notification of a Nuclear Accident;
- Convention on Assistance in the Case of a Nuclear Accident or Radiological Emergency;
- Treaty on the Non-Proliferation of Nuclear Weapons;
- Treaty Banning Nuclear Weapon Tests in the Atmosphere, in Outer Space and Under Water;
- Treaty on Prohibition of Emplacement of Nuclear Weapons and Other Weapons of Mass Destruction on the Seabed and the Ocean Floor and in the Subsoil Thereof;
- Comprehensive Nuclear-Test-Ban Treaty with Protocol;
- Agreement on Privileges and Immunities of the International Atomic Energy Agency;
- International Atomic Energy Agency Statute;
- Joint Convention on the Safety of Spent Fuel Management and on the Safety of Radioactive Waste Management;
- Convention on Supplementary Compensation for Nuclear Damage;
- Convention on Nuclear Safety;
- International Convention for the Suppression of Acts of Nuclear Terrorism;
- Convention on the Physical Protection of Nuclear Material (with amendments);
- Agreement between the European Atomic Energy Community and Montenegro regarding participation in Community arrangements for the early exchange of information in the event of a radiological emergency; and
- Agreement Between Montenegro and the International Atomic Energy Agency for the Application of Safeguards in connection with the Non-Proliferation of Nuclear Weapons.

E. Upstream

In 2010, Montenegro adopted the Exploration and Production of Hydrocarbons Act (*Zakon o istraživanju i proizvodnji ugljovodonika*)[27]. This act represents the foundation regarding the regulation in the field of exploration and production of oil and gas, as it is a basis for concession agreements for such projects. The Montenegrin offshore is divided into 13 blocs for exploration of hydrocarbons (with 3,100km^2 total).

For the purposes of exploiting offshore hydrocarbon resources, to date, Montenegro has concluded a concession agreement for exploration and exploitation of hydrocarbon resources with Consortium Eni-Novatek. Another concession agreement with Energean Oil and Gas was also signed in March 2017 (3,000km^{2}in the Adriatic Sea). The former drill has shown negative results, with the concession itself being terminated, while the latter extended its concession period, planning on future offshore drills.

F. Renewable energy

The generation of electricity from RES is rapidly developing in Montenegro. In accordance with the analysis conducted by REGAGEN, the share of electricity generated from RES in the overall volume of electricity generated in 2014 was 56.51% and in 2015, the share had slightly decreased to 50.84%.

In 2020, Montenegro registered a 43.77% share of renewable energy, exceeding its overall 2020 target. The significant increase in the share compared to the previous year can be attributed to a decrease in consumption. Sectorial targets for electricity and heating and cooling were also overreached.

In 2021, Montenegro registered a 63.55% share of RES and high-efficiency cogeneration, and is distributed as follows

- hydro: 48.76%
- wind: 4.80%
- brown coal and lignite: 43.03%
- other: 3.1%

Montenegro's target for 2030 regarding the share of energy from renewable sources in gross final consumption of energy is 50%.

To date, the Montenegro RES sector is dominated by projects using hydro power, whereas wind projects are gradually breaking through. The Energy Development Strategy 2030 presented the plan for two new hydro power plants to be completed, one on Morača and the other HE Komarnica, for which the EPCG obtained a concession for the use of natural resources, for the purpose of construction, maintenance and use of the energy facility of HE Komarnica. There are currently 38 small hydro power plants in Montenegro.

The pioneers in the wind sector are the wind power plants ("WPP") Možura (46MW) and Krnovo (72MW). Construction of WPP Krnovo has been completed and the plant commenced generation in November 2017. There are plans to construct another WPP, ie Gvozd, which is intended to be commissioned in 2024 with an installed capacity of 54MW. Moreover, a long-term lease agreement has been concluded between the Government of Montenegro and the Consortium of WPD AG, Vjetroelektrane Budva for the Brajići locality, for the construction of a WPP with a capacity over 100MW. These projects significantly influence the share of RES in the overall volume of electricity generated.

Additionally, the Government has granted a concession for a solar power plant in Briska Gora, located in the Ulcinj municipality. The capacity of the plant, which will be constructed in two phases, is 200MW. The Government is expected to procure a long-term power purchase agreement, however the electricity from the solar plant would be sold according to market prices. To date, the implementation of this project has been delayed several times.

Up to the end of 2021, 20 solar power plants owned by prosumers, ie consumers that both consume and produce, have been connected to the distribution system.

The Ministry of Economic Development and Tourism of Montenegro announced that a new set of measures are being prepared in order to smooth out the potential pressure of the ongoing energy crisis in the upcoming months. One of the measures that will be proposed to the Minister of Finance is to abolish value added tax (VAT) on solar panels.

The Government considering transitioning from previously applicable fixed feed-in tariffs. This will include launching a programme to establish auctions for RES. In addition, Montenegro intends to introduce a market support mechanism for renewable energy projects. Montenegro plans to increase the share of renewable sources in its energy mix through these auctions for RES, which will result in more private investments in this sector. In connection with this, Montenegro has commenced efforts to adopt a new law regulating the use of RES, which will lay the foundation for accelerating the growth of the share of RES in the energy mix.

In 2021, EBRD launched a new Green Economy Financing Facility in Montenegro, with the aim of improving energy efficiency. In order to increase the number of household investments in green technologies, the fund of €135 million is available to be invested in the area of the Western Balkan. Green financing in Montenegro is conducted through a local partner, CKB Bank, which offers incentive grants of 15% and 20% to households that choose to install one or more pre-determined green technologies. There are plans to expand the project further in 2022. Moreover, in 2019, Alter Modus, a microcredit institution, initiated the Green for Growth Fund providing refinancing to local institutions to lend further, or investing directly in green energy projects with a minimum target of 20% reduction in energy use and CO_2 emissions.

Biofuel

The legislative regime related to biofuel is based on the Energy Act. This Act makes it mandatory for energy companies taking part in trading oil products in the transportation sector to offer biofuels to customers. There have been the following two secondary legislative acts since 2016 Energy Act, both introduced in 2018: (i) the Regulation on Closer Criteria of Sustainability for Biofuels and Bio-fluids for Accomplishing Mandatory Share of Energy in Total Final Consumption of Energy (*Uredba o bližim kriterijumima održivosti za biogoriva i biotečnosti za ostvarivanje obaveznog udjela energije u ukupnoj finalnoj potrošnji energije*)[28] and (ii) the Regulation on Mandatory Share of Biofuels in Transportation Sector (*Uredba o obaveznom udjelu biogoriva u sektoru saobraćaja*)[29].

In 2018, Landfill LLC Podgorica (*Deponija d.o.o Podgorica*) published an invitation for a pilot project to exploit biogas to produce energy at the landfill Livade in Podgorica. To date there have not been any applicants for such projects, however the capital is still eager to pilot the project.

G. Climate change and sustainability

G.1 Climate change initiatives

Montenegro ratified the Kyoto Protocol on 4 June 2007 with the United Nations Framework Convention on Climate Change ("UNFCCC"). According to the UNFCCC and Kyoto Protocol, Montenegro is considered a non-Annex I country. Therefore, unlike the Annex 1 countries, Montenegro is not obligated to limit or reduce its greenhouse gas ("GHG") emissions. However, from 1 January 2013, the Clean Development Mechanism established by the Kyoto Protocol ceased to apply to projects developed in Montenegro.

Montenegro has also signed and ratified the Paris Agreement and, in 2019, adopted the Act on Protection from the Negative Effects of Climate Change (*Zakon o Zaštiti od negativnih uticaja klimatskih promjena*)[30]. Montenegro is one of the first countries in the Balkan region, and the first contracting party to the Energy Community Treaty, to adopt such a document. The agreement allows for the establishment of the National System for Monitoring, Reporting and Verification of Greenhouse gases, as well as the obligation to develop a Low-Carbon Development Strategy. Moreover, this will serve as a basis of an action plan and the definition of national systems for policies, measures and projections required for the implementation of the Monitoring Mechanism Regulation.

In addition to Montenegro's commitment to develop its RES sector, which is evident as Montenegro is aiming to pass the law regulating the RES sector, there have been several other initiatives undertaken. The aim of these initiatives is the harmonisation of the operation of existing power plants with the environmental and climate change standards imposed by, among others, the Renewable Energy Directive.

Montenegro sent the first three draft chapters of its National Energy and Climate Plan (NECP) informally to the Energy Community Secretariat in 2021. The drafts are planned to be finalised by the end of 2023. Montenegro has also joined the Powering Past Coal Alliance and committed to stop using coal at the latest by 2035

G.2 Emission trading

TPP Pljevlja (516MW) is the only lignite-fired plant in Montenegro and falls under the scope of the Large Combustion Plants Directive[31]. This directive has only been partially transposed through the Air Protection Act and the Decree on Limit Values for Emission into the Air from Stationery Sources (*Uredba o graničnim vrijednostima emisija zagađujućih materija u vazduh iz stacioniranih stanica*)[32]. In line with these regulations, the emission limit values for the new plants comply with the applicable Large Combustion Plants Directive[33]. However, under these regulations the existing plants are permitted to exceed the prescribed emission limit values by 250% until the end of 2025.

Montenegro seems to have also dedicated to the transposition of the key environmental protection principles set under the applicable EU legislation and environmental *acquis* of the Energy Community. In addition to the Energy Act, as the leading piece of legislation, this relates to amendments to the following legal acts: Air Protection Act (*Zakon o zaštiti vazduha*),[34] the Environmental Protection Act (*Zakon o zaštiti prirode*),[35] Environmental Act (*Zakon o životnoj sredini*),[36] Act on Liability for Damages to the Environment (*Zakon o odgovornosti za štetu u* *životnoj sredini*),[37] Act on Noise Protection in Environment (*Zakon o zaštiti od buke u životnoj sredini*)[38] and others.

The 'cap and trade' system has already been introduced. A decree defines the activities or operations that emit GHGs for which an emission permit is issued (namely industrial and energy plants), the manner of conducting the auction for the allocation of emission credits, the allocation of free emission credits, the manner of recording the allocated emission credits, as well as their transfer and use. The funds raised from the scheme are to be transferred into an Eco Fund and used for further energy efficiency measures. Montenegro is preparing for operating in accordance with the EU Emissions Trading Scheme ("ETS") and the Carbon Boarder Adjustment Mechanism ("CBAM"). ECA have been contracted by the World Bank under the Partnership for Market Implementation ("PMI") initiative to create a 'readiness support plan' (RSP) outlining where support is required for Montenegro to successfully implement carbon pricing that both delivers real emissions reductions and facilitates EU accession.

G.3 Carbon pricing

Due to the ratification of the Paris Agreement in 2017, Montenegro is obliged to reduce carbon emissions by 30% no later than 2030, which it also included as part of its national strategy.

As the front-runner in the Western Balkan region regarding decarbonisation, Montenegro introduced CO_2 taxation in line with the EU ETS.[39] Due to the CBAM, Montenegro implemented a limit on EPCG regarding allowed amount for CO_2 emissions, after which €24 per emitted tonne is to be paid. This is a first step in designing a national carbon pricing system and creating a base for future price harmonisation with the ETS market.[40]

H. Energy transition

H.1 Overview

Montenegro, as a candidate to join the European Union, is trying to align its actions to achieve zero-emission energy sector and climate neutrality.

To establish the progress of the energy transition in the region, the regional project Renewable Energy Policy Consensus ("REPCONS") was launched in 2019. This project is financed by the European Climate Foundation and has gathered experts and civil society organisations from Serbia, Bosnia and Herzegovina, and Montenegro with the aim of facilitating energy transition through greater utilisation of RES. Further, the REPCONS main objectives are to accelerate the energy transition process through defining energy policies priorities, initiating dialogue and building consensus within the expert community on policy proposals and in relation to the Energy Community 2030/2050 pathway for renewables, as well as enhancing the process of regional cooperation in the sector.

Green transition has been the focus for the Government of Montenegro. For more details see section F.

H.2 Renewable fuels

There is no current use of renewable fuels in Montenegro. However, a new law regarding RES is in progress that is intended to also address the use of renewable fuels. For more see section H.3.

H.3 Carbon capture and storage

There is a lack of a legislative framework regarding CCS and there are no ongoing projects. The current capacity of Montenegro regarding CO_2 storage potential is negligible.

H.4 Industrial hubs

Currently, there are no industrial hubs or territorial clusters.

H.5 Smart cities

In 2019, Podgorica joined EBRD Green and Smart Cities Project. The project 'Smart Parks' was initiated in Podgorica whereby smart benches and wireless hotspot points were installed. As part of the green package, the capital invests in various 'smart city' technologies. Prior to this, 'smart' parking systems as well as smart systems for air quality and noise level monitoring were developed. In 2022, Telekom, a leading telecommunications operator and the largest telecommunications company in Montenegro, introduced the first 5G network in Montenegro, which is available to 70% of the population.

I. Environmental, social and governance (ESG)

Currently, there are no updates on this.

Energy law in the Netherlands

Recent developments in the Dutch energy market

Kirsten Berger, partner, and Marc van Beuge, counsel, Houthoff, Amsterdam

Cease of production groningen field

For decades, the Netherlands produced low calorific natural gas from the Groningen field. The Groningen field was, and remains, the largest gas field in the Netherlands. It represented an important source of income for the Dutch State and played a key role in ensuring the Netherlands' security of supply. The production license for the Groningen field is held by the Nederlandse Aardolie Maatschappij B.V. ("NAM") (a 50/50 joint venture between Shell and ExxonMobil). The remaining reserves in the Groningen field are estimated at 800bcm.[1]

Due to the fact that gas production from the Groningen field induces earthquakes that cause significant damage to property, particularly in the province of Groningen, resulting in a disruption of society that is deemed socially unacceptable, the Dutch Minister of Economic Affairs and Climate Policy ("Minister") decided, on 29 March 2018, to fully cease gas production from the field in the shortest possible term to ensure public safety.[2]

Against this background, both the Gas Act and the Mining Act were amended in 2018/2019 to ensure that the NAM shall produce no more or less from the Groningen field than the volume of gas necessary to ensure security of supply. This volume and the manner in which the gas is to be produced are set out in an operational strategy, determined by the State Secretary for Economic Affairs and Climate Policy ("State Secretary"), under the Minister's responsibility, in an annual decree (*vaststellingsbesluit*). This decree is based on a proposal made by the NAM, and takes into account a forecast by Gasunie Transport Services B.V. ("GTS") of the Groningen field gas volumes required during the next so-called 'gas year', (which runs from 1 October until 30 September) in various temperature scenarios.[3]

The State Secretary has thus, as from 2018, by means of various decrees, gradually reduced the permitted volume of gas production from the Groningen field from 11.8 bcm in gas year 2019-2020 to 2.8 bcm in the current gas year 2022-2023.[4] By way of comparison, the volume of gas produced from the Groningen field a decade ago was 54 bcm and still 19 bcm only five years ago.

The State Secretary's most recent decree, dated 26 September 2022, expresses the aim to cease production from the Groningen field in October 2023, although he recognizes that setbacks may lead to postponement until 2024, and notes that the final decision to close the Groningen field has yet to be taken. In fact the State Secretary has decided, for the time being, to keep all of the current eleven gas production sites operational up to and including March 2023. This has two main advantages. It allows him to address any delay in the completion of the nitrogen plant that is set to convert high calorific gas to low calorific gas for the benefit of end-users whose facilities can only accommodate low calorific (ie Groningen) gas. It further allows him to use gas from the Groningen field as a reserve of last resort to address the effects of the war in the Ukraine on the gas market, eg shortages of gas supply to households and/or hospitals that would cause severe societal disruption.

In view of the envisaged closing of the Groningen field, the Minister published for internet consultation the proposed "Act ending gas production in Groningen field (What after zero)" which is expected to be sent to Parliament in the short-term.[5] The proposed Act, which again amends both the Gas Act and the Mining Act, identifies two phases: phase 1, which arranges the Groningen field's final production phase, and phase 2, which arranges the permanent shut down of the Groningen field.

In phase 1, a limited number of production sites will be kept operational producing a minimum flow to retain these sites as a reserve resource. In this phase, gas production can only be increased above the minimum flow if required for reasons of security of supply (i) to allow GTS to perform its statutory tasks as TSO or (ii) in the event of a high demand for low-calorific gas that can only be covered by making (limited) use of the Groningen field.

Phase 2 takes effect when the Groningen field is no longer needed as a reserve resource and can thus be shut down permanently. It is estimated to begin between 2025 and 2028. In relation to this phase, the Act will explicitly provide that no more gas will be produced from the Groningen field. The Act will also address the remaining obligations of the NAM as licensee, for instance its duty to take all concrete measures reasonably possible to safely shut down the Groningen field, and to take all measures that can reasonably expected to limit as much as possible, any adverse effects of gas production also after cease of production.

In anticipation of the above, GasTerra B.V ("GasTerra"), whose core activity is the sale of natural gas from the Groningen field, adopted a phase out plan aimed at terminating its business activities by 31 December 2024.[6] GasTerra is expected to gradually cease to perform and/or to transfer its activities. According to its annual report 2021[7] (i) it is not yet clear who GasTerra's legal successor will be, (ii) contractual counterparties under continuing contracts will be involved in any transfer of GasTerra's obligations if necessary for implementation, and (iii) GasTerra will not enter into new gas sales contracts for gas supplies after 31 December 2023, unless this becomes necessary to balance the remaining portfolio.[8]

Electricity transport capacity shortage

In the Netherlands, the electricity TSO and many of the electricity DSOs for electricity have little or no transport capacity available to accommodate new transport capacity applications. In more than one third of the municipalities the DSOs have no transport capacity available for new applicants. As a result, renewable energy and housing construction projects in an early development stage are unable to secure the transport capacity that they need. This has led to a flood of court cases and administrative proceedings between applicants and grid operators which have, so far, culminated in the following status quo.

A grid operator has the obligation -upon the request of a (potential) customer- to make an offer to transport electricity for the benefit of such customer, against a tariff and conditions which are in accordance with the Dutch Electricity Act 1998. Moreover, a grid operator shall refrain from any form discrimination between parties for whose benefit the obligation to transport applies.[9]

There is an exception to the obligation to transport, ie it does not apply insofar as the grid operator does not reasonably have the capacity available for the transport requested. A refusal to transport must however be reasoned. This entails that the grid operator has to explain why the requested transport cannot be carried out. From this explanation, which must be based on objective, technical and economic criteria, the relevant applicant must be able to conclude that no capacity is reasonably available at the time that it is be required.[10] Upon request of the party to whom transport has been refused, the grid operator shall provide the relevant information on the measures that are necessary to increase the transport capacity of the grid, for which information the grid operator shall charge such party no more than cost.[11] In applying the exception to the obligation to transport described above, the grid operator is also bound by the non-discrimination principle.

It follows from case law that the grid operator 'does not reasonably have capacity available' when there is (a reasoned forecast of) physical congestion on the relevant grid, ie that the physical limit of the maximum transport capacity is in danger of being exceeded due to the (anticipated) actual use of transport capacity by connected parties. Contractual congestion, ie the fact that capacity offered to and reserved for connected parties exceeds the maximum transport capacity of the grid, is insufficient for this purpose.

In case of expected physical congestion, the grid operator is required to follow the process set out in the Electricity Grid Code. If possible, congestion management must be applied. If not, the grid operator may refuse to make available the transport capacity.

A grid operator may, in case of physical congestion, allocate transport capacity on a first come, first served basis, ie on the basis of the order of receipt of requests for transport capacity (this method of allocation does not violate the non-discrimination principle mentioned above). The grid operator may distinguish between a party that requests an (expanded) transport offer for the first time, and a party that has previously been offered and allocated transport capacity, based on the idea that the party that does not yet have an offer can take into account in its plans that an offer may be refused if the required transport capacity is lacking.

The Minister is currently examining ways to support the capital reinforcement of grid operators to facilitate future investments in their grids that are considered crucial in the context of the energy transition.

Energy act

The proposed Energy Act (*Energiewet*) is a bill which aims to integrate and replace the current Dutch Gas Act (*Gaswet*) and Dutch Electricity Act 1998 (*Elektriciteitswet 1998*). It seeks to provide a modernised and, where possible, uniformised, legal framework for both electricity and gas, complemented by subordinate legislation containing detailed and/or more administrative provisions, with the goal of achieving the flexible legislation required to support the dynamic energy transition, including its renewables and greenhouse gas emissions reduction goals. The Energy Act aims to accommodate systems integration and the increasing number of smaller-scale decentral generation facilities. It further seeks to clarify the roles of the system operators and to facilitate the availability and exchange of digital data between the various parties in the energy sector, whilst increasing both consumer participation and protection. By contrast, the Gas Act and the Electricity Act 1998 were drafted in the 1990s with the goal of liberalising, and ensuring the optimum performance of the energy markets. The bill has yet to be submitted to Parliament.

The Energy Act consist of seven chapters, including chapter 1 which contains definitions and determines the geographical scope of the Act, and chapters 6 and 7 which contain miscellaneous and transitional provisions. The key chapters are chapters 2 through 5. Chapter 2 (Energy Markets) will contain provisions relating to market activities that can be performed using the relevant transport, storage and LNG-systems (but explicitly not the market players performing the activities). These market activities may include off-take and feed-in activities, supply, aggregation, metering and balancing. Chapter 3 (System Management) contains provisions relating to the aforementioned systems and their operators. Each of these systems has a monopolistic nature and therefore requires ex ante public law regulation to guarantee third party access and to ensure that the systems are adequately maintained, each on the basis of terms and conditions that are reasonable, transparent and non-discriminatory. Chapter 4 (Management and Exchange of Data) contains provisions regarding the processes in relation to which data must be gathered, used and exchanged, the parties involved and the applicable rules. Chapter 5 (Execution and Enforcement) contains the supervisory and enforcement duties and authorities granted to the Minister and the Authority for Consumers and Markets ("ACM"; the national regulatory authority).

Collective heat supply act

The proposed Collective Heat Supply Act (*Wet collectieve warmtevoorziening*)[12] has recently become rather controversial, following reports that the Minister aims to incorporate provisions in the proposed Act to determine that all heat supply grids -currently owned by private heat supply companies, among which a number of the large incumbent energy companies such as Eneco and Vattenfall, must become publicly owned (as is the case with electricity and gas grid in the Netherlands, all of which are owned by provinces and/or municipalities). Private companies would allegedly still have a role to play as grid operator in a joint venture with a public entity or acting as grid operator under the instruction of such public entity, and they could still fulfil the role of heat producer or heat supplier using a public grid, but the grids themselves would become publicly owned following a thirty year transition period. Thus far, the Minister has refrained from responding to or confirming the aforementioned reports, stating that he will soon send a letter to Parliament addressing the state of play of the legislative proposal.

The proposed Collective Heat Supply Act, as initially published for internet consultation, did not go unnoticed but was certainly less controversial. If adopted, it would replace the existing Heat Supply Act which regulates the supply of heat to heat consumers (ie households and small- and medium enterprises) and which has been in force since 1 January 2014. The existing Heat Supply Act primarily aims to ensure the security of supply of heat consumers, as well as to protect them against a heat supplier's potentially onerous terms and conditions since heat consumers are captive customers, ie they are unable to switch suppliers in the event that they are not satisfied with the heat supplier's performance or its supply terms and conditions.

The Collective Heat Supply Act, as currently proposed, gives a leading role to Dutch municipalities, ie local public entities, in the organisation of the heat supply market. Municipalities will be required, taking into account local heat supply and demand, to designate so-called 'heat plots' (*warmtekavels*), ie geographical areas in relation to which they are subsequently required to designate a heat supplier (*warmtebedrijf*). The heat plot and the heat supplier are both designated on the basis of statutory criteria, and public or private parties applying to be designated as heat supplier must submit a decision by the ACM to the effect that they are capable from an organisational, technical and financial perspective, to perform their statutory tasks.

A heat supplier's main statutory tasks are to realise, operate and maintain a collective heat supply system (*collectief warmtesysteem*), to connect building owners to such system, and to transport and supply heat to users that are connected to the system. A collective heat supply system is defined as a system in which one or more heat sources are made accessible by means of a heat grid for the supply of heat. In order to enable heat suppliers to recoup their investments, they are granted the exclusive right to transport and supply heat in the relevant heat area for a period of 20-30 years. In the same vein, building owners that do not wish to connect to the system must actively opt out within a pre-determined period of time, to avoid adverse effects on a heat supplier's business case once investments have been made.

Upon request, heat suppliers have the obligation to provide the municipality with a plan for their heat plot describing, among other things, how they will ensure both short and long-term security of supply and the way in which they will achieve the annual reduction of the average number of kilograms of CO_2 emitted per gigajoule of heat supplied from a maximum of 40kg in 2022 to a maximum of 25kg in 2030. Heat suppliers that exceed the statutory CO_2 emissions norm must promptly notify the ACM thereof, which may in this regard impose a maximum penalty of € 900,000 or, if higher, an amount equal to 1% of the heat supplier's annual turnover.

Finally, it is important to note that the legislative proposal aims to gradually introduce heat tariffs which cover the costs actually incurred by a heat supplier in the performance of its statutory tasks and allow for a reasonable return on investment, as opposed to the currently applicable heat supply tariffs which, for historical reasons, are still based on the alternative: natural gas.

Endnotes

1. See www.cbs.nl/nl-nl/cijfers/detail/82539NED.
2. Letter from the Minister to the Lower House of Parliament dated 29 March 2018 (TK 33529, 457).
3. *Wet van 17 oktober 2018 tot wijziging van de Gaswet en van de Mijnbouwwet betreffende het minimaliseren van de gaswinning uit het Groningenveld* (Stb.2018, 371; TK 34957); Gas Act, article 10a, section 1, sub q in conjunction with article 1 sub bc and Mining Act, article 52a-52i.
4. State Secretary Decree dated 26 September 2022, reference: PDGGO-DSGG/22368536.
5. *Wet beëindiging gaswinning Groningenveld (Wat na nul)*, published on 8 March 2021.
6. GasTerra's phase out plan has not been made publicly available.
7. GasTerra's annual report 2021, www.jaarverslag2021.gasterra.nl/download-volledig-verslag.
8. GasTerra press release dated 24 September 2020. See www.gasterra.nl/en/news/gasterra-to-be-fully-phased-out-by-31-december-2024.
9. E-Act, article 24 sections 1 and 3.
10. ACM Geschilbesluit verzoeker – Liander, zaaknummer: ACM/20/039871, 22 december 2020, paras.43-47 jo. Directive (EU) 2019/944, article 6 section 2 (previously: Directive 2009/72/EC, article 32 lid 2).
11. E-Act, article 24 section 2. In general, each grid operator is also periodically required to publish its investment plan which must, a.o., address all required expansion and replacement investments. In advance, a draft of the plan is submitted to the public (including potential connected parties) and the energy regulator (ACM) for comments (E-Act, article 21 jo. *Besluit investeringsplan en kwaliteit elektriciteit en gas*). Such investment plan must take into account requests for transport capacity from (potential) customers.
12. According to the Minister for Climate and Energy, the Act is envisaged to enter into force on 1 July 2024, with the exception of the new tariff regulation provisions which are scheduled to enter into force on 1 January 2025.

Overview of the legal and regulatory framework in the Netherlands

A. Electricity

A.1 Industry structure

Nature of the market

The Netherlands' electricity generation and supply sectors are subject to relatively light regulation, while the transmission and distribution of electricity are heavily regulated.

Key market players

Electricity generation facilities are largely foreign-owned, including by RWE, Uniper, Rijnmond Energie, Riverstone, Engie, Vattenfall and N.V. Elektriciteits Produktiemaatschappij Zuid-Nederland EPZ ("EPZ"). The national transmission grid and the interconnectors are operated by TenneT TSO B.V., while the distribution grids are operated by six regional distribution system operators ("DSOs"), including Enexis, Liander and Stedin. The largest of the 40 electricity suppliers in the Netherlands include Innogy (Essent), Eneco, Vattenfall (Nuon), Nuts Groep, Greenchoice and Engie.

Regulatory authorities

The national regulatory authority for the electricity market is the Authority for Consumers and Markets (*Autoriteit Consument en Markt*) ("ACM"), an autonomous administrative authority that does not form part of any government ministry. The ACM is responsible for monitoring compliance with the Electricity Act 1998 (*Elektriciteitswet 1998*) and is entitled to impose sanctions in this regard. The ACM also sets the connection and transport tariffs and conditions.

Legal framework

The Netherlands' electricity policy and electricity legislation are primarily determined by the minister of Economic Affairs and Climate Policy ("Minister"). The production, transport and supply of electricity are primarily regulated through the Electricity Act and secondary legislation, various Technical Codes (*Technische codes*) and a Tariff Code Electricity (*Tarievencode Elektriciteit*).

Implementation of EU electricity directives

The Third Electricity Directive is implemented by the Electricity Act.

A.2 Third party access regime

The Electricity Act incorporates a system of regulated third party access ("TPA"). On request, the Transmission System Operator ("TSO") or DSO must provide a connection to, and make an offer to transport electricity through, its grid against objective, transparent and non-discriminatory tariffs and conditions based on actual costs. The TSO or DSO may not discriminate between applicants requesting a connection or transport capacity. A connection must be built within a reasonable period of time. A request for transport capacity may only be denied if the TSO or DSO substantiates that it does not reasonably have sufficient transport capacity available.

A.3 Market design

Electricity is still largely produced from fossil fuels, but increasingly also from renewable energy sources (33%) (RES). The Coal-Fired Power Generation (Prohibition) Act, (*Wet verbod op kolen bij elektriciteitsproductie*) aims to contribute towards meeting the Netherlands' climate ambitions phasing out coal-powered electricity generation entirely by 2030.

The Dutch State ("State") is involved in the transmission of electricity but not in its generation or supply. This follows from the fact that the Netherlands has opted to implement the unbundling regime in the Third Electricity Directive through FOU. In practice, the Dutch State, through the Ministry of Finance, is the sole shareholder in TenneT Holding B.V. which, in turn, is the sole shareholder in TenneT TSO B.V., the Netherlands' electricity TSO. The transmission system is owned by TenneT subsidiaries.

Furthermore, a national Unbundling Act imposes a comparable unbundling regime on all Dutch grid operators. Its core 'group prohibition' provision, prohibits both the TSO and DSOs from being part of the same group of companies as companies engaged in production, trading and/or supply activities in the Netherlands. Network companies are also prohibited from holding any shares, directly or indirectly, in an electricity generation, trading and/or supply company or related companies in the Netherlands, and vice versa. All energy companies in the Netherlands are fully unbundled.

Grid operators must have the economic ownership of their transmission or distribution grids. The legal ownership of these grid grids, as well as the shares in the TSO and the DSOs, are required by law to be, directly or indirectly, publicly owned. The DSOs and their grids are generally owned by Dutch provinces and municipalities.

A.4 Tariff regulation

Tariff regulation is based on the Electricity Act, the Regulation tariff structures and conditions for electricity (*Regeling inzake tariefstructuren en voorwaarden elektriciteit*) and the Tariff Code Electricity. Tariff regulation for the DSOs is based on a revenue setting mechanism whereby the ACM determines the allowed revenues for the DSOs based on efficient costs of these companies, including a reasonable return. This system incentivises DSOs to improve their productivity because they achieve higher profits if their productivity is above average.

The Electricity Act determines that there are three regulated tariffs, ie a connection tariff, a transport tariff and a metering tariff. Parties pay a connection fee to the DSO to be connected to the grid. Such connection fee consists of two components: an initial connection tariff and a periodic connection tariff. Parties must further pay a transport fee to covers the costs of the transport of electricity. The metering tariff due by small end-users is the tariff for which the grid operator manages the metering devices and grants suppliers' access to metering data. The metering tariff for large end-users is liberalised.

The ACM takes a 'method decision' for each regulation period (lasting three to five years), that determines the revenue setting mechanism for the relevant type of grid operator. The ACM subsequently takes individual decisions in relation to each grid operator, based on the method decision, setting the initial revenue, the x-factor (an efficiency cut relating to the grid operators' revenues), the q-factor (a quality term, only for DSOs) and the calculation volumes (fixed sales, set in advance). The ACM also takes annual tariff decisions for each individual grid operator.

A.5 Market entry

The generation of electricity is not heavily regulated in the Netherlands. A generation licence is not required to construct or operate generation facilities but, depending on the type, size and location of the facility, there are likely to be other requirements such as spatial planning and environmental permits. The most important renewables subsidy, the Sustainable Energy Production and Climate Transition Incentive Scheme ("SDE++") (*Besluit stimulering duurzame energieproductie en klimaattransitie*), a production subsidy, is subject to heavy regulation.

The distribution of electricity is heavily regulated under the Electricity Act and its secondary legislation, including the Network Managers (Financial Management) Decree (*Besluit financieel beheer netbeheerder*), which sets the tasks of the grid operator. It contains requirements to guarantee the independence of the DSO and sets the tariffs and conditions subject to which the DSO must operate its grids. In practice, the investments required to construct a distribution grid and the know-how required to comply with the legislation present a practical barrier to potential new entrants. In principle, a grid operator must be appointed for every grid in the Netherlands. In relation to distribution systems, this duty lies with the legal owner of such grids. Only public limited companies or private companies with limited liability can be appointed as DSO, and such appointment, valid for a ten-year period, requires the Minister's consent.

The Netherlands' electricity supply sector is fully liberalised. The supply of electricity to large end-users is largely a free market activity; however, the supply of electricity to small end-users (ie end-users with a connection to a grid with a total maximum throughput capacity of 3x80A) is, in principle, subject to a licence as such end-users are considered to require a certain level of consumer protection.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Public service obligations ("PSOs") (ie service obligations imposed by the Dutch Government ("Government") on a service provider for a public interest purpose) are set under the Electricity Act and include:

- the aforementioned third-party access duties that rest on grid operators;
- the duty on grid operators and suppliers to provide small end-users with a reliable supply of electricity subject to reasonable tariffs and conditions; and
- the duty on grid operators to pursue a policy aimed at preventing small end-users from being disconnected from the grid, especially between 1 October and 1 April of any year.

Smart metering

The regulations relating to the installation and use of smart metering systems for small end-users are incorporated in the Electricity Act and the Governmental Decree on smart metering systems (*Besluit op afstand uitleesbare meetinrichtingen*). Grid operators are expected to have made smart meters available to all households in the Netherlands by the end of 2022. Smart meters are not mandatory, as small end-users can refuse to have a smart meter installed.

Electric vehicles

The Government's short-term ambition is to ensure that in 2025, 50% of all new passenger cars sold will have an electric power train and a plug, and that at least 30% of these vehicles (15% of the total) will be zero emission (ie battery or fuel cell EVs). The Government's long-term ambition is to ensure that by 2030, 100% of all new passenger cars sold will be zero-emission. A company in the same group of companies (as defined in the Dutch Civil code) as an electricity grid operator (but not the grid operator itself) is entitled to construct charging infrastructure but is not entitled to supply electricity to electric vehicles ("EVs") by means of such infrastructure. The Government has made available various tax benefits in relation to EVs and the supply of electricity by means of charging points.

A.7 Cross-border interconnectors

The Netherlands has cross-border connections with Belgium (1,501MW), Germany (3,949MW), the UK (BritNed; 1,000MW), Norway (NorNed; 700MW) and Denmark (COBRAcable; 700MW). The alternate current interconnectors with Belgium and Germany form an integral part of the national transmission system, whereas the direct current interconnectors are operated separately.

B. Oil and gas

B.1 Industry structure

Nature of the market

The Netherlands is traditionally a 'natural gas country'. It is home to the Groningen field, one of the largest gas fields in Europe (containing in excess of 500 billion cubic meters ("bcm") of gas), over 90% of its households are connected to a gas grid and it developed the TTF, one of the leading gas trading markets in Europe. By comparison, its oil production is relatively modest, at 18,000 barrels per day (as of 2020). This section will therefore focus only on natural gas.

Until recently, the Netherlands was one of the largest gas producers and exporters in Europe. In March 2018, however, the Minister took the watershed decision to cease, in the shortest possible term, the production of natural gas from the Groningen field. The production of gas will cease in order to ensure the safety in the province of Groningen where natural gas production has induced earthquakes, causing significant damage to buildings and disruptions to society that are deemed socially unacceptable. The estimated remaining reserves in the small gas fields (small by comparison to the Groningen field) is in excess of 80bcm of gas. The Government has taken the position that it will not permit the commercial exploration or production of shale gas until 2023, and there is no indication that this position will subsequently change.

Despite the Netherlands opting to implement the unbundling regime in the Third Gas Directive through full ownership unbundling ("FOU"), the State is involved in both the transmission and the supply of gas, which is permitted on the basis of the Third Gas Directive's unbundling rules because these interests are held by separate government entities. Therefore, the Dutch State, through the Ministry of Finance, is the sole shareholder in N.V. Nederlandse Gasunie ("Gasunie") which, in turn, is the sole shareholder in Gasunie Transport Services B.V. ("GTS"), the Netherlands' TSO. The transmission system is owned by GTS. The State is also involved in the supply of gas through GasTerra B.V., which is owned by the State (10% directly and 40% through EBN B.V. ("EBN")) and two energy companies (25% Shell and 25% ExxonMobil). The State holds its shares via a separate government body, ie the Ministry of Economic Affairs and Climate Policy.

The national Unbundling Act imposes a comparable unbundling regime on all Dutch grid operators. Its core 'group prohibition' provision, prohibits both the TSO and DSOs from being part of the same group of companies as companies engaged in production, trading and/or supply activities in the Netherlands. Network companies are also prohibited from holding any shares, directly or indirectly, in ana gas production, trading and/or supply company or related companies in the Netherlands, and vice versa. All energy companies in the Netherlands are fully unbundled.

Grid operators must have the economic ownership of their transmission or distribution grids. The legal ownership of these grid grids, as well as the shares in the TSO and the DSOs, are required by law to be, directly or indirectly, publicly owned. The DSOs and their grids are generally owned by Dutch provinces and municipalities.

Key market players

The largest gas producers in the Netherlands include the Nederlandse Aardolie Maatschappij, a 50/50 joint venture between Shell and ExxonMobil. NAM produces the Groningen field and a number of the small fields. Other small field producers include Neptune, ONE-Dyas, Petrogas, TotalEnergies, Vermillion and Wintershall. The national transmission grid is operated by GTS, while the distribution grids are operated by six regional DSOs, including Enexis, Liander and Stedin. The largest of the 40 electricity suppliers in the Netherlands include Innogy (Essent), Eneco, Vattenfall (Nuon), Nuts Groep and Engie.

Regulatory authorities

There are two national regulatory authorities for gas. The State Supervision of Mines (*Staatstoezicht op de Mijnen*; SodM), appointed under the Mining Act, supervises gas exploration and production safety and environmental issues. The onshore transport and supply of gas under the Gas Act, is subject to the supervision of the ACM (see section A.1).

Legal framework

The Netherlands' energy policy and energy legislation are primarily determined by the Minister. The production and offshore transport of gas is regulated under the Mining Act (*Mijnbouwwet*), whereas the transport and supply of gas are regulated through the Gas Act and secondary legislation, various Technical Codes (*Technische* codes) and a Tariff Code Gas (*Tarievencode Gas*).

Implementation of EU gas directives

The Third Gas Directive is implemented in the Gas Act.

B.2 Third party access regime to gas transportation networks

The Gas Act incorporates a system of regulated TPA. On request, the TSO or DSO must provide a connection to small end-users and, to large end-users, a connection point on the nearest point on the grid that has sufficient capacity available at an appropriate pressure for the envisaged connection. The TSO or DSO must not discriminate between applicants requesting a connection or transport capacity. A request for transport capacity may only be denied if the TSO or DSO demonstrates that it does not have sufficient transport capacity available or if the grid operator cannot reasonably be expected to make such capacity available.

B.3 LNG terminals and storage facilities

The Netherlands has one large-scale liquefied natural gas ("LNG") terminal, the 'GATE' (ie Gas Access to Europe), located in the Rotterdam port area. It has an annual regasification capacity of 12bcm; this expands to 16bcm. The initiators and partners in the GATE terminal are Gasunie and Koninklijke Vopak N.V., and the terminal is operated by Gate terminal B.V. Offtake contracts have been signed with DONG, RWE, OMV, E. ON and Eneco. A second, floating LNG terminal with a capacity of 8bcm is being developed by Gasunie subsidiary EemsEnergy Terminal B.V. in the North of the Netherlands. Offtake contracts have been signed with CEZ, Engie and Shell.

Under the Gas Act, a regulated third-party access regime applies to LNG installations. Rules on calculation methods for tariffs and conditions for access to LNG installations are set out in the Regulation access to LNG installations (*Regeling toegang tot LNG-installaties*). Requests for TPA to LNG regasification capacity may only be denied if the LNG terminal operator demonstrates that it does not have sufficient capacity available or if it cannot reasonably be expected to make such capacity available.

The Netherlands has a total gas storage capacity of over 12bcm and has five major gas storage facilities. The capacity of the Grijspkerk, Langelo/Norg and Alkmaar facilities has been contracted by Gasunie for the long term. The gas storage facilities at Zuidwending and Bergermeer, offer independent storage services to third parties. In addition, many of the large energy companies own gas storage facilities just across the German border, which are also connected to the Dutch gas grid.

Under the Gas Act, a negotiated third-party access regime applies to gas storage facilities. A gas storage operator must, on a third party's request, negotiate access to its facility if the party needs such access in a technical or economic sense to gain an efficient access to the system for the supply of grid users. The gas storage operator must annually publish objective, transparent and non-discriminatory indicative tariffs and conditions for the provision of gas storage services in the following calendar year, which form the basis for the envisaged negotiations. The grounds for refusal of TPA to gas storage capacity are the same as those in relation to gas transport capacity (see section B.2).

B.4 Tariff regulation

Tariff regulation is based on the Gas Act, the Regulation tariff structures and conditions for gas (*Regeling inzake tariefstructuren en voorwaarden gas*) and the Tariff Code Gas.

Tariff regulation for the DSOs is based on a revenue setting mechanism whereby the ACM determines the allowed revenues for the DSOs based on efficient costs of these companies, including a reasonable return. This system incentivises DSOs to improve their productivity because they achieve higher profits if their productivity is above average.

The Gas Act determines that there are three regulated tariffs, ie a connection tariff, a transport tariff and a metering tariff. For all small end-user connections uniform connection tariffs apply. For large end-users a uniform fee applies only to the connection point on the grid, whereas other components are calculated on a case-by-case basis. The transport tariff is the tariff for which a grid operator must provide transport for the benefit of the connected party. End-users must pay a standing charge for the transport service irrespective of the volume of gas used, and a capacity tariff, which differs depending on the capacity category in which the end-user is classified. The metering tariff, due by small end-users, is the tariff for which the grid operator manages the metering devices and grants suppliers' access to metering data. The metering tariff for large end-users is liberalised.

The ACM's tariff regulation related decisions are the same, *mutatis mutandis*, as those in relation to electricity tariff regulation (see section A.4).

B.5 Market entry

The exploration and production of natural gas is regulated by the Mining Act (see section F.1).

The distribution of gas and the appointment of gas grid operators is regulated under the Gas Act in the same way as the distribution of electricity and the appointment of electricity grid operators is regulated under the Electricity Act (see section A.5).

The Netherlands' gas supply sector is fully liberalised. The supply of gas to large end-users is largely a free market activity; however, the supply of gas to small end-users (ie end-users with a connection to a grid with a total maximum throughput capacity of 40 cubic metres (n) per hour) is, in principle, subject to a licence as such end-users are considered to require a certain level of consumer protection.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The PSOs in the Gas Act are the same as those in the Electricity Act (see section A.6).

Smart metering

The regulations relating to the installation and use of smart metering systems for small end-users are incorporated in the Gas Act and the Decree on Smart Metering Systems (see section A.6).

B.7 Cross-border interconnectors

The GTS transmission system is connected to transmission systems in Germany, Belgium and the UK by more than 15 border points. The 235km Balgzand Bacton Line (BBL) connects the Title Transfer Facility ("TTF") and the British National Balancing Point ("NBP") trading hubs.

C. Energy trading

C.1 Electricity trading

The Electricity Act does not regulate electricity trading in much detail. In summary, it defines traders as organisational entities that enter into agreements for the sale and purchase of electricity and provides that the Minister must appoint one or more legal entities to establish an electricity exchange, which must operate independently from any traders and vice versa.

The Netherlands' wholesale electricity market encompasses various marketplaces where electricity demand and supply can meet including the bilateral market, the over-the-counter ("OTC") market, the power spot exchange ("EPEX Spot"), the power derivatives exchange ("ICE ENDEX"), the Energy Trading Platform Amsterdam ("ETPA") and the imbalance market. On the bilateral market, generators, suppliers and large end-users trade electricity on the basis of longer term non-standardised contracts, without a broker acting as intermediary. The OTC market largely consists of trade in standardised volumes with a standard duration, generally based on the European Federation of Energy Traders (EFET) or the International Swaps and Derivatives Association (ISDA) contracts entered into through brokers. In the OTC market, trading usually concerns the psychical delivery of electricity, while at the various exchanges both physical delivery and financial settlement trades are being concluded.

The EPEX Spot and ETPA are non-regulated electricity exchanges (ie they are not subject to supervision by the Authority for the Financial Markets). Both provide for spot trade in standard volumes on the intraday and day-ahead markets. ICE Endex is a regulated electricity exchange on which standard volumes of mid- and long-term future products are traded. To act as trader, a party must become a member of the relevant exchange, must enter into various agreements (eg membership agreement, electronic user agreement) and must obtain a licence (ie a shipper licence or regulatory licence). Traders on EPEX Spot must possess either a trade recognition or a full recognition from TenneT as balancing responsible party.

C.2 Gas trading

The Gas Act regulates gas trading in the same way, *mutatis mutandis*, as the Electricity Act regulates electricity trading (see section C.1).

The Minister has appointed ICE ENDEX and ECC B.V. as gas exchanges for the Dutch market. Via a gas exchange, gas can be bought and sold on the TTF: a leading European gas trading hub operated by GTS. The TTF is a virtual trading platform based on GTS's entry-exit system. It offers market players (shippers and traders) the possibility of buying and selling gas that has been brought into the GTS system at an entry point ('entry-paid gas') to other market players multiple times before the gas leaves the system at an exit point. The seller delivers the gas on the TTF, which serves as a virtual exit point; the buyer buys the gas on the TTF, which serves him as a virtual entry point. To trade on the TTF, shippers or traders must obtain the relevant licence (A, B or C) thereby becoming a licensed balancing responsible party and subsequently register on the TTF. Gas can also be traded through bilateral agreements where seller and buyer are aware of the other's identity or OTC through brokers that bring a seller and a buyer together.

D. Nuclear energy

The Nuclear Energy Act (*Kernenergiewet*) applies to nuclear energy and installations, fissionable materials, ores, radioactive substances and devices that emit ionising radiation. It establishes that a permit from the Authority for Nuclear Safety and Radiation Protection (*Autoriteit Nucleaire Veiligheid en Stralingsbescherming*) is required for the transport, use, import and export, and disposal of fissionable material and ores, and for establishing, operating, modifying and decommissioning a facility where nuclear energy can be released.

The 485MW Borssele nuclear power plant, located in the province of Zeeland, is responsible for 2-4% of the Netherlands annual power generation. It is owned by EPZ, which is ultimately controlled by Dutch governmental entities and RWE's subsidiary, Energy Resources Holding B.V. By law, the primary permit required to operate the plant will expire on 31 December 2033, although the Government aims to keep the plant operational beyond 2033 and is considering building two new nuclear power plants.

Most nuclear plants use low enriched uranium as their power source. In the Netherlands, uranium is produced by the Urenco uranium enrichment facility (5200 tonnes per year) which is owned by the Netherlands (33%) through Ultra-Centrifuge Nederland N.V., the UK (33%) and German companies E.ON and RWE (33%).

The Central Organisation for Radioactive Waste (*Centrale Organisatie voor Radioactief Afval N.V.*), owned by the Dutch State, has a monopoly under the Nuclear Energy Act on the treatment and storage of radioactive waste and currently owns the waste. This waste is stored in a long-term storage facility in Borssele. The geological final disposal of radioactive waste is planned for the year 2130 at a yet to be determined location.

E. Upstream

The exploration and production of oil and gas, both onshore and offshore, is regulated under the Mining Act (*Mijnbouwet*), the Mining Decree (*Mijnbouwbesluit*) and the Mining Regulation (*Mijnbouwregeling*). The Mining Act applies to oil and gas that is more than 100 metres below the earth's surface,, to terrestrial heat that is more than 500 metres below the earth's surface and to the storage of substances, including carbon dioxide ("CO_2") (see section H.3). Unproduced oil and gas is owned by the Dutch State, but ownership transfers to the production licence holder upon production.

The exploration or production of oil, gas or terrestrial heat requires an exploration or production licence respectively, and the storage of substances requires a storage licence. A production licence is only granted if it is plausible that oil or gas in the area to which the licence would apply is economically extractable. Every licence applies to specified minerals, in a specified area for a specified period of time. Licences can be split, merged, transferred, extended or reduced.

The licence is generally granted to a number of mining companies (ie the licence holders), one of which is designated with the Minister's consent as the operator (ie the party that performs the actual exploration and/or production activities) while the other companies only participate financially. A licence applicant is assessed on its technical and financial capabilities, the proposed exploration or production method, and the efficiency and sense of responsibility with which previous exploration and/or production activities were performed. A licence is, in principle, granted in competition, meaning that a licence application is published so that other parties may apply for the same licence, with one main exception: an exploration licence holder that has demonstrated the presence of minerals in his licence area will in principle receive a production licence for these minerals.

The licence holder, in particular the operator, is responsible for the performance of production activities in accordance with the 'extraction plan' (*winningsplan*), which requires the Minister's approval. The licence holder must take all measures that may reasonably be expected to prevent harm to the environment, damage due to soil movement, unsafe situations and detrimental effects on the systematic management of the oil and/or gas deposits. They are also responsible for the decommissioning of mining installations that are no longer in use, and must, on the Minister's request, provide financial security in relation to his liability for soil movement and/or decommissioning costs subject to a standard decommissioning security agreement (DSA).

State-owned EBN participates in exploration activities on the licence holder's request, and in production activities unless the Minister decides otherwise. EBN and the licence holder must enter into an agreement of cooperation for exploration or production activities, which provides that the licence holder will take an interest of 60% in these activities, while EBN takes a 40% interest (ie contributes to the exploration or production costs and shares in the revenues). The licence holder's other financial obligations include paying a profit share (*winstaandeel*).

F. Renewable energy

F.1 Renewable energy

The primary legislative and regulatory regime relating to renewable energy is the SDE++. It encompasses a generation subsidy, open to companies, aimed at stimulating renewable energy generation and other greenhouse gas ("GHG") reducing technologies, including the generation of renewable electricity, gas and heat as well as CC(U)S. It subsidises excess project costs, ie the difference between the average costs and revenues of a particular technology, albeit that if the revenues are below a base price the difference between the base price and such revenues is not subsidised. Subsidies are granted for a fixed period, generally 12-15 years. The maximum possible subsidy is capped based on a pre-established number of full load hours for each technology. The SDE++ is technology neutral, ie all technologies in principle compete under the same subsidy ceiling. Subsidy applications are processed on a first come first served basis. The scheme opens in phases, with each phase providing access to a higher subsidy amount per 1,000kg of GHG reduction. Subsidy can be granted by the Netherlands Enterprise Agency (*Rijksdienst voor Ondernemend Nederland; RVO*) acting on behalf of the Minster.

F.2 Renewable pre-qualifications

SDE++ subsidy applications must include the permits required for the construction and operation of the relevant generation installation (eg a wind farm). Applications must further include a feasibility study, consisting of a description of the installation, an exploitation calculation, a financing plan and a statement regarding the applicant's equity. In addition, applications must include the permission of the owner of the location where the installation is to be established if the owner of the installation does not own the location. Depending on the relevant technology, additional information may be required including a statement from the grid operator that there is sufficient transport capacity available to accommodate the renewable energy that is to be fed into the grid.

F.3 Biofuel

The Renewable Energy Directive's provisions requiring member states to set an obligation on fuel suppliers to ensure that the share of renewable energy within the final consumption of energy in the transport sector is at least 14% by 2030, have been implemented through the Environmental Management Act (*Wet milieubeheer*), which is elaborated in the Energy for Transport Decree (*Besluit energie vervoer*) and the Energy for Transport Regulation (*Regeling energie vervoer*).

In broad outline the system revolves around two types of companies, bookers and suppliers for end-use, all registered in the Energy for Transport Registry (*Register Energie voor Vervoer, REV*) which is managed by the Dutch Emissions Authority (*Nederlandse Emissieautoriteit; NEa*) ("DEA"). A company may be both a booker and supplier for end-use.

A booker (*inboeker*) is a company that brings volumes of biofuels or other forms of renewable energy on to the Dutch market that are destined for transport end-use, and books these volumes of renewable energy in the register renewable energy. For each gigajoule of renewable energy that is booked, the booker receives one renewable fuel unit (*hernieuwbare brandstofeenheid;* ("RFU")). The biofuels must be sustainably produced, and the biofuel chain must be secured by a sustainability system recognised by the European Commission ("Commission"). A volume of renewable energy can only be booked once. There are different types of RFUs. RFUs can be traded.

A supplier for end-use (*leverancier tot eindverbruik*) supplies transport fuels (gasoline, diesel and heavy fuel oil) to 'petrol station operators' for end-use by road or railway vehicles. Each supplier for end-use has a so-called 'annual obligation renewable energy' (*jaarverplichting hernieuwbare energie*). To meet this obligation, the supplier must, on 1 May of each year, have in its account at least the numbers of RFUs, per type, that jointly correspond with a percentage (17.9% in 2022 gradually increasing to 28% in 2030) of the energy content of the transport fuel that the company supplied for end-use in the preceding calendar year. On the same date, the DEA cancels the numbers of RFUs corresponding to the supplier's annual obligation from the supplier's account. If a supplier does not have sufficient RFUs, they must compensate the shortage. The DEA may impose an administrative penalty on the supplier in case of a shortage.

G. Climate change and sustainability

G.1 Climate change initiatives

The Netherlands' Climate Act (*Klimaatwet*) entered into force on 1 September 2019. The Climate Act sets 'politically enforceable' goals for climate policy and offers a framework for developing policies aimed at irreversibly and gradually reducing GHG emissions in the Netherlands to a level that is 95% lower in 2050 compared to 1990, in order to limit global warming and climate change. To achieve this target, a 49% reduction in GHG emissions by 2030 is pursued as well as a fully CO_2-neutral electricity generation by 2050.

The Climate Act identifies the Climate Plan (*Klimaatplan*) as the key national climate policy instrument. The current Climate Plan, adopted in April 2020, relates to the period 2021-2030. A new Climate Plan will be adopted at least once every five years. The Climate Plan is incorporated in the Netherlands' integrated national energy and climate plan that it must send to the Commission every ten years.

The Climate Act further provides that the PBL Netherlands Environmental Assessment Agency will present a Climate and Energy Outlook (*Klimaat- en Energieverkenning*) to the Minister once a year, consisting of a scientific report on the consequences of the climate policies pursued over the previous year. The Minister annually sends the Outlook to Parliament together with the Climate Report (*Klimaatnota*), which sets out any additional measures necessary to achieve the above-mentioned goals and which biannually contains a report on the execution of the Climate Plan.

G.2 Emission trading

The European Union Emissions Trading System ("EU ETS") Directive is implemented in the Netherlands by means of the Environmental Management Act (*Wet Milieubeheer*), the Emissions Trading Decree (*Besluit handel in emissierechten*) and the Regulation on the monitoring of emission trading (*Regeling monitoring handel in emissierechten*).

The operation of an installation that emits GHG is prohibited without a permit (including a GHG emissions monitoring plan) from the board of the DEA which must decide on applications within four months. The installation operator must, prior to 1 May of each year, surrender a number emission allowances that is at least equal to the installation's emissions during the preceding calendar year established in accordance with the Union Registry Regulation. An operator that does not surrender sufficient allowances is subject to a penalty of €100/tonne of CO_2. Payment of the penalty does not release the operator from the obligation to surrender sufficient allowances. An operator may transfer excess allowances to third parties that hold a Union Registry account or, if necessary, purchase additional allowances from such third parties to cover its installation's emissions. Once the transfer of an allowance has been completed the invalidity, nullification or termination of the transfer agreement, no longer affects the validity of the transfer. Emission allowances qualify as property rights (*vermogensrechten*), but it is not possible to attach them or encumber them with a pledge or usufruct.

In principle, the board of the DEA decides, per trading period, on the allocation of free allocation, ie the allowances that are not auctioned. Its decision can be amended by a judgement of the Administrative Jurisdiction Division of the Council of State and/or by the Commission. At present, the Replacement national allocation decision of GHG emission allowances 2021-2025 (*Vervangend nationale toewijzingsbesluit broeikasgasemissierechten 2021-2025*) sets out the numbers of allocated free allowances and the installations to which they have been allocated.

G.3 Carbon pricing

In addition to the EU ETS, the Environmental Management Act and the Environmental Taxes Act (*Wet belastingen op milieugrondslag*) have introduced two additional national pricing mechanisms, each aimed at stimulating the relevant companies to invest in measures that reduce their CO_2 emissions:

- a tax aimed at setting a minimum (ie floor) price for CO_2 emissions by EU ETS companies that generate electricity (*Minimum CO_2-prijs elektriciteitsopwekking*), which increases by 10% a year from €21.30 in 2020 to €31.90 in 2030. The tax equals the difference, if any, between the floor price and a lower EU ETS price. Thus, if the EU ETS price is higher than the floor price the tax rate equals zero; and
- a carbon tax (*CO_2 heffing industrie*) which applies to EU ETS installations in general as well as number of non-EU ETS installations. In 2022, the carbon tax equals a base amount of €41.75 per tonne CO_2-equivalent (the base amount is indexed annually) which will increase by €10.87 a year up to and including 2030. EU ETS installations pay the base amount decreased by the EU ETS price per tonne of CO_2 emissions (the price is set annually; for 2022 this was €60.78). If the EU ETS price is higher than the base amount, the carbon tax equals zero (as is the case in 2022). Non-EU ETS installations pay the full amount of the carbon tax. The carbon tax is paid for the annual volume of CO_2 emitted decreased by the number of so-called 'dispensation rights' for emissions that are exempted from the carbon tax (the total amount of which is annually reduced).

G.4 Capacity markets

The Netherlands' does not apply a capacity mechanism as meant in the Internal Market for Electricity Regulation. In the event of a scarcity of electricity, the Netherlands relies on market forces to provide sufficient investment incentives in production capacity to meet electricity demand.

H. Energy transition

H.1 Overview

In 2021, a total of 118TWh of electricity was produced in the Netherlands, of which 33% (39.1TWh) originated from renewable sources: 17.9TWh from wind, 11.3TWh from solar and 9.7TWh from biomass.

The Netherlands expects its share of energy from renewable sources in the EU's gross final consumption of energy in 2030 (EU target: 32%) to be within a bandwidth of 27-35%, ie just above the share of 26% in 2030 that results from the Governance Regulation's Annex II formula. To this end, the Netherlands aims to achieve an offshore wind electricity generation of 49TWh by 2030 and an onshore electricity generation from wind and solar of 35TWh as from 2025 up to 2030.

In terms of energy efficiency, the Netherlands aims to achieve a primary energy consumption of 1950PJ by 2030, which the Commission (EU target: 32.5%) finds sufficiently ambitious. Its potential contribution to final energy consumption of 1837PJ in 2030 is, however, considered to reflect only a modest ambition.

H.2 Renewable fuels

The Government Strategy on Hydrogen (*Kabinetsvisie waterstof*) was published on 30 March 2020. In addition, a National Hydrogen Programme Work Plan 2022-2025 (*Werkplan Nationaal Waterstof Programma 2022-2025*) was published on 7 July 2021.

At present, there is no comprehensive regulatory framework in place regarding the production, storage, transportation or supply of hydrogen. The Minister does not consider the definition of 'gas' in the Dutch Gas Act to apply to hydrogen, which is why the majority of the provisions in the Gas Act do not apply to hydrogen.

The Government Strategy sets a target to scale up electrolysis capacity for the production of green hydrogen to about 500MW of installed capacity by 2025 and 3-4GW of installed capacity by 2030. Hydrogen production, including electrolysis, is in principle viewed as a commercial activity that is reserved for private (ie not publicly owned) market participants.

At present, grid operators (*netbeheerders*) are prohibited by law from playing a role in relation to hydrogen. The ACM has however published a temporary framework setting out a tolerance policy for the involvement of grid operators in hydrogen pilot projects in the built environment. Furthermore, the government envisages a national hydrogen grid to be developed, owned, operated and exploited by Gasunie subsidiary Hynetwork Services B.V., subject to legislation that ensures reasonable, objective and non-discriminatory grid access against reasonable tariffs.

The Gas Act and the Electricity Act give network companies (*netwerkbedrijven*) a limited role in relation to hydrogen, ie the construction and management of pipelines or installations for hydrogen.

H.3 Carbon capture and storage

The Government considers carbon capture and storage ("CCS") to be an important (transition) technology to making Dutch industries more sustainable and essential to achieving Dutch CO_2-reduction targets before 2030. The estimated storage capacity of depleted gas fields at sea is 16 million tonnes of CO_2.

CCS is supported by the aforementioned carbon pricing mechanisms and (financially) supported mainly through the SDE++ scheme which subsidises the capture of CO_2 for a period of 15 years. After 2035, the SDE++ subsidy will no longer be granted to CCS projects, reflecting its role as a transition technology.

Although the Government intends to allow market participants to develop CCS projects, it envisages specific roles for certain state participations:

- EBN can monitor, and where necessary, stimulate research into the suitability of CO_2 storage locations, optimise the re-use of existing infrastructure for CCS and EBN will be given a mandatory involvement in CO_2 storage activities and may also be appointed as the party that will manage CO_2 storage locations once the relevant CO_2 storage permits have been revoked.
- Gasunie will be given the necessary room, within the limits set by the Gas Act, to participate in the realisation of CO_2 transport infrastructure and the transport of CO_2. The appointment of a public or regulated transport grid operator is however not envisaged.

The CCS Directive has been implemented by the Mining Act. The Mining Act provides that it is prohibited, without a licence, to store substances (including CO_2) or engage in prospecting for CO_2-storage complexes. A licence holder must, in principle, provide TPA to his CO_2-storage complex.

H.4 Oil and gas platform electrification

The Q13 offshore gas platform, operated by Neptune, is electrified by a cable transporting renewable electricity from the shore to the platform. ONE-Dyas is planning an electrified gas platform for the production of its newly discovered N05 gas reservoirs. Presently, legal impediments prevent the large-scale electrification of offshore platforms by means of connections to an offshore wind farm or the offshore electricity grid.

H.5 Industrial hubs

The Netherlands has five main industrial hubs: (i) Port of Rotterdam-Moerdijk, (ii) Chemelot, (iii) North Sea Canal Area (Noordzeekanaalgebied), (iv) Schelte-Delta and (v) Northern Netherlands (Noord-Nederland). There is no legislative framework specifically for the development of industrial hubs.

H.6 Smart cities

Amsterdam (17), The Hague (23) and Rotterdam (27) are all listed in the top 30 of the IMD-SUTD Smart City Index Report 2021. There is no legislative framework specifically for the development of smart cities.

I. Environmental, social and governance (ESG)

The financial services sector is increasingly giving priority to financing organisations and/or projects aimed at meeting the UN's sustainable development goals (SDGs), including achieving net-zero GHG emissions. ESG is often prioritised whether or not an organisation is under pressure from its shareholders, employees, customers or private citizens.

Energy law in North Macedonia

Recent developments in the energy market of North Macedonia

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Introduction

Despite the challenging year of 2021 due to the COVID-19 pandemic, the energy market of North Macedonia was under continuous development. One of the more notable events was the appointment of the electricity market operator, MEMO SPLLC Skopje ("MEMO"), as the organised electricity market operator. MEMO's role is to organise and administer the day-ahead and the intraday electricity market. At the end of 2020, the Assembly of North Macedonia adopted the Law on Purchase of the Shares of Makpetrol JSC Skopje ("Makpetrol") in the gas TSO JSC GA-MA Skopje ("GA-MA"). In August 2021, the Government of North Macedonia ("Government") purchased Makpetrol's share in GA-MA making GA-MA fully state-owned. In December 2022, a merger occurred between GA-MA and NER JSC Skopje ("NER"), where both of these companies were dissolved and a new company JSC for performing energy activity natural gas transmission NOMAGAS Skopje ("NOMAGAS") was established. NOMAGAS is in full state ownership and will use all licenses and acts of GA-MA.

Additionally, the Law on Energy Efficiency was adopted in 2020, which transposes into national law the European Union ("EU") Energy Efficiency Directive, Energy Performance of Buildings Directive, Regulation on Labelling of Energy Related Products, and Directive on Eco-design of Energy Related Products.

Electricity market liberalisation and novelties

The electricity market was fully liberalised in 2019 and the results are already visible. There has been an increase in the number of consumers which independently choose their supplier of electricity. In 2020, more than half of the total consumption, ie 52.24% of the needs were provided on the open electricity market.

On 1 July 2019, the Energy and Water Services and Services for Municipal Waste Management Regulatory Commission of the Republic of North Macedonia ("ERC") stopped regulating the price of electricity generation of the largest electricity generator in North Macedonia, JSC ESM ("ESM"). Generators, suppliers, and traders of electricity are now able to conclude electricity purchase contracts without obtaining prior approval from the ERC. The increased competitiveness in the electricity market is a direct result of the market liberalisation reforms, and consumers are benefiting from better offers and services as a result.

According to the 2020 Annual Report of the ERC, the regulated supplier (EVN Makedonija JSC Skopje and EVN HOME LLC Skopje) in 2020 observed a continuous reduction in the total amount of electricity purchased, which correlates with the process of the full liberalisation of the electricity market.

In line with its appointment as electricity market operator, MEMO will be responsible for the market coupling between the electricity market of North Macedonia with the electricity markets of the region, with the Bulgarian electricity market being the priority.

On the balancing market, system services are procured on a transparent and competitive basis, and opportunities have been created to establish a transparent price for calculating deviations. In 2020, the TSO and part of the active suppliers and/or traders started purchasing electricity for compensation.

The ERC approved new Grid Rules for Electricity Transmission of JSC MEPSO Skopje in December 2021 which intend to transpose the Grid Connection Codes of the EU. In addition, in the second half of 2022, the ERC worked on adopting secondary legislation in accordance with the Energy Law for the implementation of the Regulation (EU) no. 1227/2011 of the European Parliament and of the Council of 25 October 2011 on wholesale energy market integrity and transparency ("REMIT Regulation").

The gasification continues

Investments in the gasification of North Macedonia continue. The interconnection with Greece is close to realisation. NER and the Greek operator DESFA prepared a feasibility study about the pipeline, while in 2019 an investment grant of 20% of the value of the project was approved through the Western Balkan Investment Fund, and a grant for the preparation of project documentation and techno-economic analysis was approved from the European Commission.

The construction of the main gas pipelines from Stip to Negotino and Bitola, and from Skopje to Tetovo and Gostivar continues, while authorities plan to construct a main gas pipeline from Gostivar to Kicevo and Ohrid as well. A tender for the construction of the main gas pipeline from Negotino to Gevgelija is expected to be published, while construction of the gas pipeline from Sveti Nikole to Veles is expected, although there is no exact date for this.

Currently, a tender procedure for awarding a contract on establishing public-private partnership ("PPP") for the financing, building, managing, maintaining, and developing the distribution system of natural gas in the Republic of North Macedonia is ongoing. As set out in the invitation to tender published by the Ministry of Economy, the private partner should, within four years of receiving each individual construction permit, build at least 50% from the envisaged primary natural gas distribution network in urban municipalities and at least 20% in rural municipalities. In 2020, two bidders were pre-qualified in the first phase of the tender procedure performed as competitive dialogue and the procedure continued in 2022. The submission of the final offer from the bidders is expected to be in 2023.

The Government announced that NER and ESM each signed a memorandum of understanding with the Greek companies Gastrade and Damko Energy, indicating that NER intends to acquire a share in Gastrade and ESM would like to book the capacity at the liquefied natural gas ("LNG") terminal for the next 15 years. ESM will participate with 25% in the share capital of Alexandroupolis Electricity Production, the company that is expected to finance, construct, own, and operate the gas-fired power plant.

North Macedonia plans to invest over €380 million in the 800MW power plant and €370 million in a 10% stake in the LNG terminal.

In the upcoming period (no specific date has been given), the TSO will be certified, and activities will be undertaken in preparation for the natural gas transmission facilities and the introduction of the 'entry-exit' concept, as well as the approval of the by-laws of natural gas distributors.

Growth of the RES sector

Prior to the adoption of the Energy Law in 2018, feed-in tariffs were the available support mechanism for the generation of electricity from RES. With the adoption of the Energy Law, feed-in premiums were introduced. In 2020 there was an increase in the number of RES power plants, with 38 new projects being developed, of which six are hydro power plants ("HPPs"), and 32 are photovoltaic ("PV") power plants. By the end of 2020, therefore, there were 295 RES power plants in total, out of which 203 use premium feed-in tariffs, while 91 do not use support measures for the generation of electric energy. By the end of 2021, there were 344 local RES power plants, out of which 202 use feed-in tariff, 7 use premiums, while 135 do not use support measures for the generation of electric energy. According to the latest information published by the ERC, in 2022 the ERC issued 267 licenses for production of electricity from RES, with total installed capacity of 152.2 MW.

ESM investments

ESM announced that it had signed a €2.4 million agreement with the German KfW Development Bank to invest in green energy. The grant will be used to finance the preparation of feasibility, environmental impact, and social aspects related to the planned green energy projects such as PV plants with a total capacity of over 140MW at the REK Bitola TPP, the construction of a wind park in Miravci, rehabilitation of HPPs, the upgrade and modernisation of the Energetika complex and setting up a central heating network in Bitola. The implementation of these projects is expected to increase electricity generation by about 650GWh.

The Government instructed ESM to conduct a feasibility study and prepare the necessary documentation for the construction of a 300MW to 350MW PV power plant near Stip.

Measures to tackle climate change

North Macedonia is fulfilling its obligations towards the Energy Community as it was the first country of the Western Balkans region to submit its draft National Energy and Climate Plan ("NECP") to the Secretariat. The NECP contains a set of measures proposed by each member state of the EU to achieve the EU's energy and climate goals; however, there will be different targets for North Macedonia as it is not a member of the EU.

In this regard, the Energy Community Secretariat welcomed the general proposed targets, in particular:

- 82% greenhouse gas net emissions reduction relative to 1990 levels by 2030;
- 20.8% savings of final energy consumption;
- 34.5% savings of primary energy consumption relative to business as usual; and
- 38% share or RES in gross final energy consumption by 2030

The Secretariat emphasised several areas in the draft NECP that need to be improved.

ESM is also active on the climate change front, announcing its intent to implement an internal mechanism to price carbon emissions of its plants and operators by the end of 2021, after the Energy Community Secretariat invited all electricity generators in the Energy Community to implement an internal carbon pricing mechanism with its support. In its letter of intent, ESM states that the carbon pricing mechanism will be applied in the absence of a mandatory emission pricing regime and that the level of internal carbon price will relate to the level of the market price of carbon emissions and its projections under the EU Emission Trading System.

HPP Cebren tender

After several unsuccessful attempts in the previous years, the construction project for the HPP Cebren on the Crna river and the operation of the existing HPP Tikves is underway, after ten foreign companies and consortiums submitted prequalification offers, out of which nine companies were selected.

The project is planned to be realised via PPP, with ESM as the public partner. The planned investment will be between €500 million and €600 million.

The HPP will have a generation capacity of around 333MW, for a yearly generation of 1,000GWh of electricity. This will result in a yearly save of 913,000 tonnes of CO_2.

Ongoing and planned projects

After the first unsuccessful attempt in 2019, in February 2020 the Government issued a public notice for participation in a PPP for a solar park project worth an estimated €80 million. A year later, Solarpro Holding, a solar energy equipment supplier from Bulgaria and Fortis Energy Eletricity from Turkey, were selected to build PV power plants at the location of the old mine in Oslomej. Both companies will build one PV power plant, each with an installed capacity of 50MW. This will increase the country's energy independence and stability of supply and will also open the possibility of new energy interconnections with the country's neighbours.

The second phase of the WPP 'Bogdanci' will comprise of three to four wind turbines, resulting with a total installed power of 13.2MW, and nominal annual generator of electricity of 37GWh.

A tender for the preparation of a feasibility study for the justification for awarding a PPP or selling TPP 'Negotino' was published in the first half of 2021.

The Government has granted the status of 'strategic investment project' to several energy projects. The following are the names and installed capacity of some of them: the Solar Park Stipion project of Akuo with about 400MW, the Mytilineos Cogeneration Plant Skopje with up to 150MW, the Wind Park Virovi project of WPD with 414MW, and the Green Energy Plant project of Zoka Energy Solutions with an installed capacity of 34MW. Currently, there are ongoing negotiations between the Government and the strategic investors for the realisation of these projects and it is expected to sign strategic investment agreements with some of them in the near future.

Mergers and acquisitions

Two merger clearance notifications were submitted to the Commission for Protection of the Competition of North Macedonia ("Notification(s)"), related to acquiring control in two companies developing wind parks in North Macedonia:

- Wind Park Bogoslovec: In line with the Notification, Green for Growth Fund, Southeast Europe SA, SICAV-SIF and BNB Company LLC Skopje acquired joint control in Thor Impeks SPLLC Skopje, a company constructing a 36MW wind park on the territory of Sveti Nikole and Stip, having a temporary status of preferential generator of electricity.
- Wind Park Euroing: In line with the Notification, Interenergo d.o.o. Slovenija acquired sole control in the company Park na Veterni Elektrani LLC Gevgelija, which has a temporary status of preferential generator of electricity and develops a 30MW wind farm on the territory of Bogdanci and Stojakovo.

Dispute settlement

After warning was issued in February 2021, the Energy Community Secretariat launched a dispute settlement procedure against North Macedonia for failing to meet the limits for air pollution emissions in 2018 and 2019. North Macedonia has failed to comply with the ceiling for sulphur dioxide and dust set out in its National Emission Reduction Plans. The Secretariat initiated a preliminary procedure, which provides an opportunity for the country to react to the accusation of non-compliance within two months. On 21 February 2022, the Energy Community Secretariat submitted a Reasoned Opinion against North Macedonia, which is the second step in a dispute settlement procedure initiated by the Secretariat.

New amendments in the energy legislation

The end of 2022 brought along amendments in the energy legislation. The new amendments to the Law on Energy are aimed at bringing its compliance with the Law on Strategic Investments, the Law on Inspection, the Law on Electronic Documents and Electronic Identification, as well as with other acts.

In addition to the above, the ERC adopted decisions approving:

1. The new Grid Codes for the Distribution of Thermal Energy adopted by ESM HEAT DISTRIBUTION DOOEL Skopje;
2. The new Electricity Market Rules adopted by ERC;
3. The new Rules for Balancing the Electricity Power System;
4. The new Rules for Balancing the Natural Gas Distribution System;
5. The Grid Codes for Amending and Supplementing the Grid Codes for Natural Gas Distribution System;
6. The Contractual Terms in the proposed Contract for the Distribution of Natural Gas; and
7. The Rules for Procurement of Natural Gas to Cover Losses in the Natural Gas Transmission System.

The first electricity stock exchange in Republic of North Macedonia

MEMO announced that the first electricity stock exchange in the Republic of North Macedonia will start operating in the first half of 2023 and it will introduce a reference price of electricity, which is now calculated according to the Hungarian HUPEX Exchange.

The rules for trading on the stock exchange have already been prepared and it is expected that they will be adopted by ERC by the end of February 2023, after which the trial period of operation of the electricity stock exchange will begin.

Overview of the legal and regulatory framework in North Macedonia

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in North Macedonia was fully liberalised in 2019. This liberalisation was initiated in 2007, by giving large industrial consumers the right to purchase their electricity on the free market. The second phase of liberalisation came into force on 1 April 2014, when 222 large companies in North Macedonia were given the status of qualified consumers, and thereby gained the right to purchase electricity on the free market.

The way to full liberalisation was paved with the adoption of the Energy Law (2018, "Energy Law"), when all consumers were given an opportunity to choose their supplier of electricity. Additionally, households and small consumers can now choose whether to be supplied by a universal supplier or enter the free market and be supplied by other licensed suppliers. In early 2019, the Government of North Macedonia ("Government") chose the consortium between EVN Macedonia JSC Skopje and EVN Elektrosnabduvanje SPLLC Skopje as a universal supplier through a tender procedure. All 28 licensed electricity suppliers were eligible to run for the position of universal supplier. The JSC Power Plants of North Macedonia ("ESM"), as the biggest electricity generator in North Macedonia, will sell to the universal supplier pre-determined volumes of electricity until 2025. With this, the Government is trying to avoid any rapid increases of the electricity price and protect customers in this regard, which is not unexpected bearing in mind the previous practices of keeping the electricity price capped below the actual market price as a form of social policy.

Key market players

The process of restructuring the former Electric Power Company of North Macedonia was finalised in 2006. As part of the Government's programme to liberalise the electricity market, the restructuring resulted in the unbundling of this vertically integrated company into three legally separated enterprises:

- The Electricity Transmission System Operator ("TSO") of the Republic of North Macedonia, JSC for Transmission of Electricity and Management with the Electricity System, state-owned, Skopje ("JSC MEPSO"), which is 100% state-owned. JSC MEPSO is responsible for transmitting electricity and managing the high voltage transmission network, operating the electricity central dispatching system, and implementing market operations, providing electricity supply for regulated wholesale customers, and providing ancillary services. JSC MEPSO established MEMO SPLLC Skopje, which is the electricity market operator and organised electricity market operator.
- The 100% state-owned JSC ESM, which is the largest generator of electricity. ESM controls the two major thermal power plants ("TPPs"), ie TPP Bitola and TPP Oslomej, with a total capacity of 825MW and operates eight major hydro power plants ("HPPs") with a total installed capacity of about 550MW.
- The private JSC EVN Macedonia, which is a part of the EVN Austria group, operates the distribution and supply of electricity in North Macedonia. EVN Austria holds 90% of the stocks in the distribution company. EVN Macedonia also controls the other two significant HPPs, ie, Kalimanci and Matka, with a total installed capacity of about 24MW. EVN Home LLC Skopje is the universal supplier and supplier of last resort of electrical energy.

In accordance with the full ownership unbundling ("FOU") requirements under the Energy Law, JSC MEPSO is owned by the Ministry of Transport and Communications, while ESM remains under the control of the Government.

Regulatory authorities

The most important state body responsible for the energy policy and overall control of the energy sector is the Ministry of Economy, in particular its Department for Energy.

The Energy and Water Services and Services for Municipal Waste Management Regulatory Commission ("ERC") was established in 2002 as a regulatory body independent of the interests of the energy industry and governmental bodies. The ERC is composed of seven commissioners appointed by the Assembly of North Macedonia. The most important function of this body is the issuing, amending, and revoking of energy licences, and regulation of the prices and tariff systems for different types of energy.

Further responsibilities of the ERC include ensuring safe, secure, continuous, and quality energy supply to final consumers, protection of the environment and nature, protection of competition and consumers in the energy sector, as well as other responsibilities set out in the respective regulations.

The other relevant body in the electricity sector in North Macedonia is the Energy Agency, established in 2005 under the Law on Establishment of the Energy Agency. The Energy Agency is responsible for supporting the implementation of the national energy policy, primarily by preparing various strategies and programmes, as well as by promoting energy efficiency and utilisation of renewable energy sources ("RES").

Legal framework

The main piece of legislation regulating the energy industry and market in North Macedonia is the Energy Law. The Energy Law takes the form of an umbrella law, covering all significant areas such as electricity, renewable energy, oil and gas, and regulation of the markets, transport, and transmission of energy.

In 2020, a new Law on Energy Efficiency was adopted, the purpose of which is to decrease the energy needs through efficient use of energy by implementing energy efficiency measures.

Implementation of EU electricity directives

North Macedonia was granted candidate status to join the European Union ("EU") in 2005, with a recommendation that accession negotiations begin in 2010; however, accession negotiations began 12 years later, specifically on 19 July 2022. Additionally, North Macedonia is a contracting party to the Energy Community Treaty and in 2018 held the presidency in office and chaired the key institutional meetings within the organisation. As a member of the Energy Community, North Macedonia is obliged to harmonise its national legislation with the applicable EU acquis. In line with this commitment, but after missing the deadline for transposing the EU Third Energy Package, the National Assembly finally adopted the Energy Law in May 2018, and thereby rectified the breach that had occurred.

The Energy Law introduced eligibility for all customers to choose their electricity supplier instead of the five-stage process of liberalisation of the electricity market, which was supposed to end in 2020. In addition, the Energy Law further strengthens the capacities of the competent institutions and imposes a requirement for FOU on the TSO for electricity and natural gas. To enable full implementation of the new legislative solutions in the field of energy, there is an ongoing process of preparing and adopting the relevant secondary legislation. This will also result in changes in the energy sector, particularly regarding the administrative procedures and the day-to-day activities of the energy companies.

In 2020, the Energy Efficiency Law was also adopted, which aligns the national legislation with energy efficiency regulation at EU level, an area previously regulated with the provisions of the old Energy Law.

In addition to the Energy Law, the applicable strategies at national level are another pillar of the energy legislation of North Macedonia. Such strategies include the Strategy for Energy Development until 2030, Strategy for Energy Development until 2040, Strategy for Utilisation of RES until 2020, and the Strategy for Energy Efficiency Improvement until 2020.

North Macedonia has also adopted the National Action Plan for Energy Efficiency (adopted in 2021), as well as the Fourth National Action Plan for Energy Efficiency (2020 – 2022) (adopted in 2021).

A.2 Third party access regime

Under the Energy Law, TSOs and Distribution System Operators ("DSOs") are obliged, on the basis of the published tariffs, to allow all system users access to the relevant system in a transparent and objective manner that prevents discrimination between them. The relevant TSO or DSO can deny access to the grid when: (i) there is an electricity distribution or transmission capacity shortage; (ii) the enabling access to a certain user can jeopardise the security of energy supply in North Macedonia; or (iii) the provision of access to the appropriate system would obstruct the relevant TSO or DSO from fulfilling its public service obligation. In cases of denied access, the relevant TSO or DSO must inform the applicant in writing, providing a detailed and clear explanation of the reasons for denial of access. The Energy Law also requires priority access for and priority treatment when dispatching electricity from RES or high-efficiency cogeneration plants.

The TSO or DSO, under the relevant grid code, must specify the connection rules for the grid and the connection charge-setting methodology. Entities applying for energy system connection or users applying for alteration to an existing connection must submit a grid connection application to the relevant TSO or DSO. Furthermore, JSC MEPSO is obliged to provide third party access in an objective, transparent, and non-discriminatory manner.

A.3 Market design

Under the Energy Law, there are regulated and unregulated energy activities within the energy market of North Macedonia. The transmission of electricity, organisation, and management of the electricity market, and electricity distribution are considered regulated energy activities in the electricity sector.

To obtain a licence for the performance of an unregulated energy activity, market entrants must establish a local branch office or a trade company in the Central Registry of North Macedonia; if the market entrant wishes to obtain a licence for undertaking a regulated energy activity, it must register a trade company in accordance with the applicable legislation in North Macedonia. The ERC is the body authorised to grant energy licences. A maximum licence term of up to 35 years is granted to entities that perform the following energy activities: generation, transmission, distribution, transit, and operation of a system for transmission and distribution of electricity. For other energy activities, licences are issued for a period of ten years. Licences are granted on fulfilment of the relevant technical, financial, and other criteria required for performance of energy activities. One legal entity can hold several licences for unregulated energy activities.

A.4 Tariff regulation

The tariff regulation system for regulated energy activities in North Macedonia is comprised and regulated by acts of ERC, rulebooks and tariff systems pertaining to transmission, distribution, and sale of electricity activities. Tariff systems for regulated periods of time under specific market conditions are prepared and submitted by the TSOs and DSOs to the ERC for approval.

Transmission

The transmission tariff regulation system is governed by the ERC in accordance with the relevant rulebook on transmission. The ERC issues a decision approving requests summitted by the TSO for regulated periods of three years at a time, which are subject to annual review. The average tariff is regulated by determining the upper limits of income that the TSO is permitted to obtain during a calendar year. The TSO submits the request to the ERC until 15 May, at the latest, within the first year of the regulated period for transmission and distribution of electricity, ie, in the current year for organising and managing the electricity market.

The Tariff System for Transmission and Marketing of Electricity[1] determines the tariffs for use of the transmission system. This tariff system applies a system based on calculated elements and sum of compensation foreseen in the system and applies these calculations to a monthly billing system by which the TSOs invoice their users.

Distribution

The tariff system for distribution of electricity is regulated through implementation of the relevant rulebook. The activity of distribution of electricity is foreseen for regulated periods of three years at a time. The relevant tariff systems for distribution of electricity by the ERC determine the criteria and basis for formation of the distribution system use tariffs.

Consumers

The sale and purchase of electricity in the regulated market is performed under prices and conditions approved by the ERC for periods of 12 months at a time. To date, EVN has maintained its monopoly for the supply of electricity to households and the price of the supplied electricity is strictly regulated by the ERC.

Following the adoption of the Energy Law, the ERC adopted the Tariff System for Sale of Electricity to Consumers Supplied by Universal Supplier and Supplier of Last Resort[2] ("Tariff System"). This Tariff System regulates the sale of electricity to consumers and households that choose to be supplied by the universal supplier. The Tariff System enters into force at the same time as the universal supplier's licence and replaces the Tariff System for Sale of Electricity to Households and Small Consumers.

In accordance with the Energy Law, the ERC adopted the Rules for Supply of Electricity for the Universal Supplier,[3] which regulates the procedure for supply of the universal supplier who is obliged not only to supply customers that have chosen this supplier but is also a supplier of last resort.

Tariff regulation is governed by the ERC by way of approval of appropriate requests submitted ex-post by the TSO and DSO in accordance with the law and rulebooks governing sale, transmission, and distribution of electricity for different categories of consumers that participate in the regulated or unregulated market.

Pricing is regulated by the ERC, which determines the highest limit of income that an entity is permitted to gain during a calendar year through regulated average prices.

The transmission and distribution tariff regulation is subject to the Rulebook on the Manner and Conditions for Determining the Regulated Maximum Income and Regulated Average Tariffs for Transmission of Electricity, Organising and Managing the Electricity Market and Distribution of Electricity[4] for a regulated period of three years for transmission and/or distribution of electricity.

A.5 Market entry

Licences in the electricity sector can only be awarded to companies (regulated energy activity) or companies and branch offices (unregulated energy activity) that are established in North Macedonia. To be supplied with the appropriate licence, an applicant must fulfil numerous requirements in relation to technical characteristics, qualification of staff engaged, and financial position.

Under the reciprocity criteria, a local branch office of a foreign entity can carry out these activities in North Macedonia following registration in the proper register for foreign suppliers. However, the founder must be a holder of a licence or other document for performing trade or supply of electricity in a country that is a contracting party or participant to the Energy Community Treaty.

Licensing regime

The Energy Law states that legal entities must obtain a licence to perform energy activities in North Macedonia. These licences are issued for a period of three to 35 years, depending on the activity in question, the funds required, the duration of the right to use the respective energy resource and the submitted request for the activity performed. The procedure for obtaining a licence is regulated by a Rulebook on Licences[5] ("Licences Rulebook"). Every company registered in the Central Registry of North Macedonia can apply for a licence. The old by-laws required that the legal entity must have an energy activity as its registered principal activity in the Central Registry. The Licences Rulebook prescribes the issuance of a temporary licence for an energy project that enters into trial operation. This licence is issued in specific situations prescribed by the Energy Law, ie, upon request for the issuance of a licence by an investor before obtaining approval for use of the energy facility or before receiving the examination report giving a technical overview by an authorised engineer for facilities that do not require usage approval. In any case, on receipt of the usage approval or the report of the technical overview of the facility, the ERC issues a licence for performing the energy activity pursuant to the temporary licence.

Under the Energy Law, licence holders must apply for changes to their licence only if there are changes to the manner in which the activity is performed. Other changes (eg, ownership structure, status, name or address, amendments to the registration form of the company) are notifiable to the ERC.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Performers of regulated energy activities must meet the requirements for performing a public service. The holder of a licence for undertaking a regulated energy activity must provide a public service in North Macedonia in the manner provided by and in accordance with the prices and tariffs prescribed and/or approved by the ERC. In addition, the Government can decide to impose an obligation to performers of unregulated energy activities to perform a public service for a certain period of time. The Government obtains an opinion from the ERC and other competent authorities before imposing this obligation on certain legal entities.

Smart metering

The Energy Efficiency Law prescribes the obligation for TSOs and DSOs to increase the energy efficiency by introducing advanced metering systems and smart networks. The ERC, through the tariffs for transmission and distribution, secures the installation of multifunctional smart meters to electricity consumers which will reflect the actual consumption of energy.

Electric vehicles

Electric vehicles ("EVs") are mentioned in the Law on Vehicles[6] (2008), where they are classified as vehicles from the first ecological category. Other than this, there is no additional legislation in North Macedonia regulating EVs.

A.7 Cross-border interconnectors

A new Rulebook on Allocation of Cross-Border Transmission Capacities[7] has been in force since November 2019. JSC MEPSO, as a TSO, is obliged to allocate the available cross-border transfer capacities in a transparent, non-discriminatory, and market-oriented manner. JSC MEPSO can allocate the cross-border capacities on the interconnection lines with the neighbouring TSOs in Serbia, Bulgaria, Greece, and Kosovo by organising an auction on its part from the available capacities in cooperation with a neighbouring TSO, or participating in the regional auction office for coordinated allocation of the available capacities. The allocation of cross-border capacities is conducted through yearly, monthly, weekly, and intra-day auctions.

There are five 400kV interconnections with the neighbouring states, ie, two with Greece, one with Bulgaria, one with Serbia and one with Kosovo. The work on the preparatory stages of the project Bitola 2-Elbasan has intensified and the construction of this interconnection between North Macedonia and Albania started in 2022. In April 2021, a work group of engineers and managers of the system operators of Albania and North Macedonia was established, that will coordinate and speed up the activities for the construction of the interconnection.

JSC MEPSO implements coordinated auctions through the Coordinated Auction Office in Southeast Europe on the border with Greece and Kosovo. Joint auctions are performed on yearly, monthly, and daily and intra-day on the border with Bulgaria and Serbia.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

The local oil market encompasses several activities, such as oil refining and production of oil derivatives, production of biofuel, transport of crude oil through pipelines, wholesale of crude oil, oil derivatives, etc. The Energy Law regulates which energy activities in the oil sector are carried out based on a licence from the ERC and the primary requirements for performing such activities. The local infrastructure includes only one oil pipeline, which is used for transport of crude oil from the refinery in Thessaloniki, Greece, to the refinery in OKTA. However, this pipeline is currently not operational due to a dispute between the majority shareholder (Helenic Petroleum) and the minority shareholder (North Macedonia). It is expected that the involved parties will overcome the dispute and restart the transport of oil through this pipeline, although a timeline for this is not yet known.

In 2020, there were no imports of crude oil or refining of crude oil and production of oil derivatives by the OKTA refinery. To date, there are around 30 licensed wholesale traders in the oil market.

The maximum retail prices for certain oil derivatives and fuels for transport are set by the ERC.

Key market players

The key market player in the oil market is OKTA Oil Refinery JSC Skopje, with EL.P.ET Balkanika, Greece, as its majority shareholder. OKTA has the capacity to produce motor gasoline, diesel fuel, jet fuel, liquefied petroleum gas, as well as commercial butane. Another notable market player is Makpetrol JSC Skopje ("Makpetrol"), whose refinery for production of biodiesel fuel has a yearly capacity of 30,000 tonnes. Makpetrol is also a leading company with respect to number of owned petrol stations; out of 372 local petrol stations Makpetrol owns 127. Lukoil Macedonia SPLLC Skopje is next with 32 petrol stations and there are 27 petrol stations under the brand OKTA. The rest of the petrol stations are owned by other local companies. In 2020, there are two entities that import natural gas: Makpetrol and TE-TO JSC.

Regulatory authorities

Participants in the oil sector on behalf of the State of North Macedonia ("State") are the Ministry of Economy, the ERC, the Energy Agency and the Compulsory Oil Reserves Agency or North Macedonia.

Legal framework

The Law on Compulsory Oil Reserves[8] entered into force in October 2014 transposing the Minimum Stocks of Crude Oil and/or Petroleum Products Directive, the amendments of which provide that it begins to apply from 1 January 2021. The Government was obliged to form compulsory oil reserves no later than 31 December 2022.

Gas

Nature of the market

North Macedonia is a fully dependant gas importing country. The system for transmission of natural gas that supplies North Macedonia is part of a Russian transit gas pipeline on International Corridor 8, which passes through Ukraine, Moldavia, Romania, and Bulgaria. The connection with the system in Bulgaria is on the eastern border, in the area called Deve Bair, and goes to Skopje. The cul-de-sac branch of this transmission system includes a 98km pipeline, one entry point, six main exit points with 52 regulating and metering stations, and more than 60km of distribution network.

Experts suggest that the undeveloped infrastructure and the low price of electricity are the two main reasons that the natural gas market in North Macedonia is still underdeveloped. Another influential factor is the long and active dispute between the State and Makpetrol over the ownership of the transmission system. The relevant stakeholders are working to expand the infrastructure by building the primary distribution network, with focus on the pipelines, Skopje-Tetovo-Gostivar and Stip-Negotino-Bitola. The construction of these pipelines is nearing its end, with predictions being that the construction will be finalised by mid-2023.

The cities Strumica and Kumanovo have continuously developed the distribution network in their municipalities, through licensed companies Strumica Gas and Kumanovo Gas. The Directorate for Technological Industrial Development Zones has obtained a licence for the implementation of the energy related activities of natural gas distribution, natural gas supply of last resort and natural gas supply to tariff-based consumers that are located in the special industrial zones and connected to the distribution network. Makpetrol-Prom Gas (a subsidiary of Makpetrol) holds national licences for supply of natural gas and supply of last resort.

Key market players

The key market player in the gas market in North Macedonia is Makpetrol, which is a major importer and exporter of natural gas in the country. In 2006, the Government and Makpetrol jointly established the public company GA-MA, which was the TSO for natural gas until December 2022 and held a licence for transmission of natural gas. The ownership of GA-MA has been the subject of numerous disputes in the past. Towards the end of 2020 the Assembly passed a law to have the Government buy out Makpetrol's share in GA-MA. The transaction was completed in 2021, and GA-MA became solely owned by the State.

In December 2022, a merger occurred between GA-MA and the state-owned NER (which was involved in the development of the national gas transport system, thus playing an important role). With the merger, both of these companies were dissolved, and a new company NOMAGAS, fully owned by the Government, was established. NOMAGAS will use all licenses and acts of GA-MA.

Regulatory authorities

Participants in the gas sector on behalf of the State are the Ministry of Economy, the ERC and the Energy Agency.

Legal Framework

The Energy Law governs the gas sector of the energy market in North Macedonia. Gas energy activities as defined by the Energy Law consist of the following:

- Natural gas transmission;
- Natural gas transmission system operation;
- Natural gas distribution;
- National gas supply; and
- Trade of natural gas.

Additionally, based on the Energy Law, the ERC adopted the Rulebook on Natural Gas Market,[9] which regulates the conditions of the natural gas market and the natural gas trade.

Implementation of EU gas directives

The Energy Law is in compliance with the Second Gas Directive concerning common rules for the internal market in natural gas.

NOMAGAS is bound to provide an operational management system for natural gas transmission and third-party access to the system on a transparent and non-discriminatory basis, in accordance with national legislation, which is harmonised with EU directives.

B.2 Third party access regime to gas transportation networks

Under the Energy Law, the TSO and DSO must provide access to the relevant infrastructure on an impartial, transparent, and non-discriminatory basis, based on the principle of regulated access for third parties, and under prices and tariffs approved by the ERC.

The relevant TSO or DSO can deny access to the grid when there is a distribution capacity shortage. The enabling of access to a certain user can jeopardise the security of energy supply in North Macedonia, if the provision of access to the appropriate system would obstruct the relevant TSO or DSO from fulfilling its public service obligation. In cases of denied access, the relevant TSO or DSO must inform the applicant in writing, providing a detailed, and clear explanation of the reasons for denial of access.

In addition, the ERC can exempt the TSO or DSO from the obligation of granting access to third parties in case of serious economic and financial difficulties of the operator due to its take-or-pay commitments arising from previous contracts.

B.3 LNG terminals and storage facilities

There are no LNG terminals or gas storage facilities in North Macedonia.

B.4 Tariff regulation

The ERC adopted the tariff system for distribution of natural gas[10] in 2018, as well as the tariff system for natural gas transmission and natural gas market[11] in 2018, and a new tariff system for natural gas transmission and natural gas market adopted in 2022. These are the principal procedures for the determination of tariffs and the charging regime, containing calculation methodologies.

The ERC determines the tariffs for a period of one year. The fee for the use of the natural gas distribution system is paid by consumers connected to the natural gas distribution system. The fee for the use of the transmission system is invoiced by the TSO with monthly invoices to the users of the natural gas transmission system.

B.5 Market entry

Licences in the gas sector can only be awarded to companies (regulated energy activity) or companies or branch offices (unregulated energy activity) that are established in North Macedonia. To obtain the appropriate licence, applicants must fulfil numerous requirements in relation to technical characteristics of the facilities, qualification of staff engaged, and financial position. Entry into the gas market is also subject to requirements imposed by laws and regulations governing other sectors, such as concessions, environmental protection, etc.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The TSO NOMAGAS is 100% owned by the State, while the licensed supplier with public service obligations Makpetrol-Prom Gas is fully owned by Makpetrol. Additionally, Makpetrol has a licence for gas trade and is one of the biggest importers of Russian gas in North Macedonia. Therefore, a vertically integrated company is concurrently involved in supply and system operation, which does not comply with the Third Energy Package and the unbundling requirements. In previous years, there has been a trend towards increased import of natural gas by the Combined Cycle Cogeneration Power Plants, primarily by TE-TO JSC. During 2021, the dominant share of 79.24% in the consumption of natural gas in North Macedonia was held by the generators of electricity and thermal energy, ie, the combined plants for the generation of electricity and thermal energy.

Smart metering

Under the Energy Efficiency Law, the ERC works together with the relevant market participants on the installation of multifunctional electricity meters and smart meters which will measure the true energy consumption of the final consumer, as well as provide real time information on the use of energy, including natural gas.

B.7 Cross-border interconnectors

North Macedonia currently has only one cross border interconnection in use, which is located on the border with Bulgaria in the area called Deve Bair.

In 2021, NER and ESM signed Memorandum of Cooperation to invest in a project for the construction of a floating LNG terminal and a gas power plant in Alexandroupolis in Greece. North Macedonia will invest 25% in the construction of the 800MW power plant and acquire 10% of the LNG terminal.

C. Energy trading

C.1 Electricity trading

To perform electricity trading, it is necessary to obtain a licence from the ERC.

Under the Energy Law, trade in electricity can be performed on a special exchange market set up for that purpose. However, to date, such market has not been established in North Macedonia. The market coupling project between Bulgaria and North Macedonia started in 2018, however it is yet to occur. The Ministry of Economy predicts that the integration of the electricity markets will occur in the beginning of 2023.

C.2 Gas trading

Under the Energy Law, natural gas traders must purchase natural gas for the purpose of selling it to other traders, suppliers, electricity and/or heating energy generators, natural gas TSOs and DSOs, as well as customers abroad.

To trade in natural gas, the interested legal entity must obtain a licence for that energy activity, which is granted by the ERC.

According to the official information published by the ERC in the Annual Report for 2021, by the end of 2021 there were 16 active licensed traders with natural gas.

D. Nuclear energy

No nuclear energy is currently generated in North Macedonia. While there were talks about North Macedonia investing in the nuclear power plant Belene in Bulgaria, this project is yet to be implemented.

The Law on Banning the Construction of Nuclear Power Plants in the Socialist Federal Republic of Yugoslavia from 1989 was undertaken as a law of North Macedonia with the Constitutional Law on Implementation of the Constitution of the Republic of North Macedonia. Under this law, the construction of nuclear power plants on the territory of Ex-Yugoslavia is banned. North Macedonia continues to apply this law so this restriction currently appears to be in force; the ban could however be lifted by enacting a new law.

E. Upstream

North Macedonia does not currently have any upstream oil and gas activities.

F. Renewable energy

F.1 Renewable energy

Energy authorities of North Macedonia and respective regulations tend to promote the generation of energy by using RES as much as possible, in line with the current international and EU tendencies. The Energy Law classifies facilities generating electricity from RES as facilities of public interest. The ERC plays a major role in the promotion of RES on the energy market in North Macedonia and is authorised to make decisions with regards to the feed-in tariffs for purchase and sale of electricity generated and delivered from RES. Under the Energy Law, to stimulate construction of new power plants that use RES, these generation facilities can acquire the status of privileged generator of energy, and therefore the right to sell the generated electricity at feed-in tariffs. The status of privileged generator is provided separately for each generation plant of electricity from RES.

For the purposes of increasing the energy from RES in the national energy mix and ensuring a higher level of competitiveness for support of this type of energy generation, the Energy Law introduced the feed-in premium mechanism. Privileged generators of electricity who do not use feed-in tariffs can benefit from a feed-in premium through tenders and auctions. However, unlike the feed-in tariff support scheme, the beneficiaries of feed-in premiums do not have guaranteed purchase of the generated electricity by the electricity market operator. The Ministry of Economy is responsible for the implementation of this support scheme and for entering into agreements for using premiums.

The Energy Law and the applicable RES secondary legislation also set up a guarantee of origin ("GO(s)") system with regards to the energy generated from RES. Specifically, GOs can be obtained by electricity generators that generate electricity from RES and that do not have the status of privileged generator, ie do not use feed-in tariffs or feed-in premiums. Each GO is issued for electricity of 1MWh and as a general rule such guarantees are valid for 12 months. GOs can be transferred from the holder of the guarantee to another licence holder for generation, trade, or supply of electricity in North Macedonia.

F.2 Renewable pre-qualifications

As per the Decree on Measures for Support of the Production of Energy from RES[12] (2019), there are certain conditions which the power plant must meet for the generator to acquire the status of a privileged generator who uses feed-in tariffs, or privileged generator who uses feed-in premiums.

In general, these include: (i) not exceeding a certain threshold of generation capacity (depending on the type of the power plant); (ii) having a construction permit, authorisation for construction of a power plant or a concession or a PPP contract; and (iii) an exclusive connection to the appropriate system with an independent metering point.

F.3 Biofuel

Under the Energy Law, the production of fuels intended for transport by mixing petroleum products and biofuels and wholesale of biofuels and transport fuels are unregulated energy activities. Entities which perform such activities must obtain a licence and must also fulfil certain conditions and requirements in respect of their premises, equipment, and facilities for performing such energy activities.

According to the Strategy for Energy Development up to 2040, a progressive use of biofuels in the transport sector is envisioned with the purpose of decreasing the greenhouse gas emissions. Additionally, the percentage of use of biofuels is expected to be increased up to 10% until 2030. To accomplish this purpose, a Law on Biofuels and action plan had to be adopted until 2022. Although planned, the Law on Biofuels is currently in its draft phase and is yet to be adopted.

G. Climate change and sustainability

G.1 Climate change initiatives

North Macedonia is not yet an EU Member State and is a non-Annex I country of the United Nations Framework Convention on Climate Change. Therefore, North Macedonia is not obliged to implement the EU Climate Change Package and is not subject to greenhouse gas emissions reduction commitments under the United Nations Framework Convention on Climate Change. North Macedonia has signed and ratified the Paris Agreement.

North Macedonia has several legislative acts that directly or indirectly affect climate change initiatives and climate change sustainability, which include:

- Law on the Quality of Ambient Air,[13] of which one of the main objectives is the prevention and reduction of pollution that causes climate change;
- Law on the Environment,[14] which implements the Clean Development Mechanism from the Kyoto Protocol;
- Strategy for Energy Development up to 2040, which sets out the main objectives in the field of energy development until 2040;
- Fourth Action Plan for Energy Efficiency (2020-2024);
- Rulebook on RES,[15] which regulates in detail the types of RES and the functioning thereof;
- Rulebook on Highly Efficient Combined Facilities,[16] which regulates in detail the types of efficient combined facilities and the functioning thereof;
- Second National Environmental Action Plan, a document released by the Ministry of Environment and Physical Planning of North Macedonia, which focuses on mitigation of climate change in North Macedonia;
- Action Plan for Renewable Energy Sources of the Republic of Macedonia until 2025;[17]
- Decree on Measures to Support the Production of Electricity from Renewable Energy Sources;[18]
- Rulebook on Privileged Generators Who Use a Privileged Tariff;[19]
- Rulebook on Energy Performance of Buildings,[20] which regulates the minimum requirements for energy efficiency in new buildings and the manner of control thereof;
- Energy Efficiency Law;[21] and
- Energy Law,[22] one of the key legal documents for promoting the use of energy from RES.

G.2 Emission trading

North Macedonia is not part of the EU Emission Trading System ("EU ETS"). Additionally, North Macedonia does not currently have the emission trading concept incorporated in its legislative acts.

G.3 Carbon pricing

North Macedonia does not have carbon pricing in its legislation. In 2021, ESM announced that it will start calculating the carbon price for the emissions of its own power plants by the end of 2021. The calculation is only for internal purposes, and it is not included in the sales price. The carbon price will be incorporated in all investment decisions and its level will be based on the market price set under the EU ETS. This voluntary initiative is expected to accelerate the transition towards a sustainable energy sector.

G.4 Capacity markets

There are currently no capacity markets in North Macedonia.

H. Energy transition

H.1 Overview

The Strategy for Energy Development up to 2040 offers a progressive outlook on the planned energy transition for North Macedonia. The main focus of all scenarios pursuant to the strategy is energy efficiency and the use of RES, which paves the way to access of funds (especially those of the EU and international financial institutions) that recognise the importance of providing support to projects for energy transition. It is expected that non-carbon fuels will play a much bigger role in the future consumption of primary energy, whereas the biggest increase will come from RES. Technological progress is expected to accelerate the energy transition.

H.2 Renewable fuels

As of December 2021, biofuels are regulated with the Energy Law. Furthermore, biodiesel fuel is produced in the refinery owned by Makpetrol, which has the capacity of 30,000 tonnes per year. Under the Strategy for Energy Development up to 2040, North Macedonia is expecting to achieve a 10% use of biofuels until 2030. For this purpose, a Law on Biofuels as well as a relevant action plan must be adopted.

Furthermore, when talking about the use of RES in the transport sector, the Strategy for Energy Development up to 2040 prescribes that criterion for the sustainability of biofuels and bioliquids must be implemented in the legal framework.

H.3 Carbon capture and storage

As of December 2022, North Macedonia does not have the carbon capture and storage concept incorporated in its legislative acts.

H.4 Oil and gas platform electrification

One of the priorities prescribed with the Energy Law is the decrease of use of fossil fuels, by substituting the same with RES. This is especially important in the industry and transport sectors; however, it is yet to be implemented in the legislation.

H.5 Industrial hubs

Since 2007, with the adoption of the Law on Technological Industrial Development Zones ("TIDZ"), North Macedonia has been attracting investors to build their production capacities in these industrial zones. As a state aid, TIDZ offers benefits and exemptions to investors which stimulate their manufacturing activities and contribute to the development of new technologies. Some of these benefits include tax exemptions of up to ten years (such as personal and corporate income tax, as well as customs duties and VAT), and notably, free connection to natural gas, water, electricity as well as access to a main international road network.

H.6 Smart cities

In March 2019, the capital Skopje became the first city in North Macedonia which joined EBRD's Green Cities initiative. For this purpose, a Green City Action Plan was adopted, which will help Skopje to fight climate change and implement measures for energy efficiency in the city.

I. Environmental, social and governance (ESG)

North Macedonia is slowly increasing and stimulating the use of energy from RES. According to the Strategy for Energy Development up to 2040, the construction of small HPPs down the valley of the river Vardar is planned between 2025 to 2030. In recent years, construction of small HPPs has been met with animosity from numerous environmental organisations and the local population, due to the fact that construction of the same is perceived as a threat to the environment, especially the rivers. Various protests have been organised against the construction of small HPPs, the main argument being that the levels of energy generation are small in relation to the damage caused to the environment and the health of the people. In the Strategy for Energy Development up to 2040, it is noted that construction of small HPPs should be assessed carefully, to avoid any negative implications to the environment.

Endnotes

1. Tariff System for Transmission and Marketing of Electricity ("Official Gazette of the Republic of North Macedonia" nos. 95/2019 and 103/2019).
2. Tariff System for Sale of Electricity to Consumers Supplied by Universal Supplier and Supplier of Last Resort ("Official Gazette of the Republic of North Macedonia" nos. 146/2022, 211/2022 and 258/2022).
3. Rules for Supply of Electricity for the Universal Supplier ("Official Gazette of the Republic of Macedonia" no. 172/2018 and "Official Gazette of the Republic of North Macedonia" nos. 126/2019 and 66/2022).
4. Rulebook on the Manner and Conditions for Determining the Regulated Maximum Income and Regulated Average Tariffs for Transmission of Electricity, Organising and Managing the Electricity Market and Distribution of Electricity ("Official Gazette of the Republic of North Macedonia" nos. 95/2019,103/2019, 161/2020 and 143/2021).
5. Rulebook on Licences ("Official Gazette of the Republic of North Macedonia" nos. 51/2019, 214/2019, 114/2020, 246/2020 and 44/2021).
6. Law on Vehicles ("Official Gazette of the Republic of Macedonia" nos. 140/2008; 53/2011; 123/2012; 153/2012; 70/2013; 164/2013; 138/2014; 154/2015; 192/2015 and 39/2016, and "Official Gazette of the Republic of North Macedonia" 161/2019).
7. Rulebook on Allocation of Cross-Border Transmission Capacities ("Official Gazette of the Republic of North Macedonia" nos. 228/2019 and 294/2020).
8. Law on Compulsory Oil Reserves ("Official Gazette of the Republic of Macedonia" nos. 144/2014, 178/2014, 199/2015, 197/2017 and 7/2019 and "Official Gazette of the Republic of North Macedonia" nos. 275/2019, 150/2021 and 236/2022).
9. Rules on Natural Gas Market ("Official Gazette of the Republic of North Macedonia" no. 126/2019 and 285/2022).
10. Tariff System for Distribution of Natural Gas ("Official Gazette of the Republic of Macedonia" no. 245/2018).
11. Tariff System for Natural Gas Transmission and Natural Gas Market ("Official Gazette of the Republic of North Macedonia" no. 285/2022).
12. Decree on Measures for Support of the Production of Energy from RES ("Official Gazette of the Republic of Macedonia" no. 29/2019 and "Official Gazette of the Republic of North Macedonia" no. 278/2019).
13. Law on the Quality of Ambient Air ("Official Gazette of the Republic of Macedonia" nos. 67/2004, 92/2007, 35/2010, 47/2011, 59/2012, 163/2013, 10/2015 and 146/2015 and Official Gazette of the Republic of North Macedonia nos. 151/2021).
14. Law on the Environment ("Official Gazette of the Republic of Macedonia" nos. 53/2005; 81/2005; 24/2007; 159/2008; 83/2009; 48/2010; 124/2010; 51/2011; 123/2012; 93/2013; 187/2013; 42/2014; 44/2015; 129/2015; 192/2015; 39/2016 and 99/2018 and Official Gazette of the Republic of North Macedonia nos. 89/2022 and 171/2022).
15. Rulebook on Renewable Energy Sources ("Official Gazette of the Republic of North Macedonia" nos. 112/2019, 240/2019 and 138/2022).
16. Rulebook on Highly Efficient Combined Facilities ("Official Gazette of the Republic of Macedonia" nos. 128/2011 and 73/2015).
17. Action Plan for Renewable Energy Sources of the Republic of Macedonia until 2025 (Official Gazette of Republic of Macedonia nos. 207/2015 and 51/2017).
18. Decree on Measures to Support the Production of Electricity from Renewable Energy Sources ("Official Gazette of the Republic of North Macedonia" nos. 29/2019, 278/2019 and 236/2021).
19. Rulebook on Privileged Generators Who Use a Privileged Tariff ("Official Gazette of the Republic of North Macedonia" nos. 116/2019 and 93/2021).
20. Rulebook on Energy Performance of Buildings ("Official Gazette of the Republic of Macedonia" nos. 94/2013, 7/2015 and 176/2015).
21. Energy Efficiency Law ("Official Gazette of the Republic of North Macedonia" nos. 32/2020, 110/2021 and 236/2022).
22. Energy Law ("Official Gazette of the Republic of Macedonia" no. 96/2018 and "Official Gazette of the Republic of North Macedonia" no. 96/2019 and 236/2022).

Energy law in Norway

Recent developments in the Norwegian energy market

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Energy policy

Implementation of the Third Energy Package and Supplementing Regulations

In November 2019, the EU Third Energy Package was implemented into Norwegian law. The package had been subject to heavy debates between stakeholders and politicians in Norway, particularly with regard to Norway's participation in the Agency for the Cooperation of Energy Regulators ("ACER") and ACER's decision-making power; see below on the ongoing litigation on this topic.

Norway is represented in ACER by the Norwegian Energy Regulatory Authority ("NVE-RME"), which in 2019 was established as an independent unit within the Norwegian Water Resources and Energy Directorate (NVE). NVE-RME participates in ACER's work but has no voting rights. The decision-making authority in cases concerning Norway is assigned to the EFTA Surveillance Authority (ESA), which may adopt individual decisions with respect to NVE-RME.

On 18 June 2021, the Norwegian Parliament enacted the implementation of four of the Third Energy Package delegated regulations (Network Codes) into Norwegian law. The guidelines on capacity allocation and capacity management (CACM), electricity balancing (EB), forward capacity allocation (FCA), and system operation (SOGL) formally entered into force in Norway on 1 August 2021. Norwegian law is, however, in certain aspects already accommodated to such guidelines to ensure a functioning market coupling regime with EU countries.

The EU Clean Energy Package has been subject to public consultation in Norway. However, the legislative acts are yet to be included in the EEA agreement, and it is uncertain when they will be implemented into Norwegian law.

Limitation on ownership in cross-border interconnectors

Ownership in cross-border interconnectors for electricity has been a matter of debate for several years. In 2016, the Energy Act 1990 was amended to open up to private ownership in such infrastructure, ie, a possibility for 'merchant lines'. As a result of compromises in the process leading up to the implementation of the Third Energy Package, this possibility has been reversed. On 31 May, the Norwegian Parliament enacted the reversal, which sets out that only the transmission system operator ("TSO") (or companies controlled by the TSO) can get a licence to own and operate cross-border interconnectors.

An exemption was made for possible hybrid interconnectors that may be constructed in connection with the future development of offshore wind on the Norwegian continental shelf. Such infrastructure may be owned by private parties, but Statnett, the Norwegian TSO, will also have system operation responsibilities for hybrid connections.

The amended Energy Act entered into force on 1 July 2021, however, projects that had already applied for a licence under the former regime will still be handled under the regime in force at the time of the application. This has practical importance for the North Connect project and was accordingly part of the political debate.

White paper on the Norwegian energy business

On 11 June 2021, the Norwegian Government ("Government") presented a white paper on energy policy "*Putting Energy to Work – Long term value creation from Norwegian energy resources*". This is the first white paper in five years and to some extent it builds on the 2016 white paper "*Power for change – an energy policy towards 2030*". However, the new white paper takes a broader approach and also covers the petroleum industry.

At a high level, the Government focuses on four goals:

- value creation which gives the basis for employment in Norway;
- further increased electrification and a realisation of the 'green shift';
- the establishment of new profitable industries; and
- continued development of the oil and gas industry, within the framework set by targets for emission reductions.

An area of particular focus in the white paper is the development of the offshore wind industry in Norway. This is dealt with in separate legislative initiatives (see further below). In addition, particular attention is given to the development of value chains for hydrogen. To that end, the white paper includes a separate section entitled "Road map for Hydrogen", which departs from, and details, the 2020 Hydrogen strategy document published by the Government. The roadmap sets out the short-term (2025) and mid-term (2030) ambitions to be achieved through a cooperation between the public and private sector. The short-term ambitions focus on the maritime sector, on production facilities for blue and green hydrogen, and pilots for developing and demonstrating new technology, while the mid-term ambitions focus on the logistics, full scale production of blue hydrogen with CCS, and market opportunities in Europe for hydrogen production. The white paper further outlines the policy instruments to be applied by the Ministry to support the ambitions, including initiatives to apply Contracts for Difference (CfDs).

Opening of areas for development of offshore wind production

The Offshore Energy Act was enacted by the Norwegian Parliament in 2010. To date, activity has been limited, but in June 2020 the Government formally opened two areas for offshore wind development. The Government also issued a regulation (the "2019 Offshore Wind Regulation") providing directions for developers with respect to the application processes.

Parts of the opened areas are well suited for fixed installations, whereas other areas are mainly suited for floating production facilities. Various national and international market players have shown very significant interest in applying for permits for development – both of fixed and floating production capacity. At the time of writing, however, no formal applications have been submitted as, subsequent to the opening of the areas, the process has shown that more detailed guidance is needed.

On 11 June 2021, the Ministry of Energy and Petroleum proposed amendments to the offshore energy act and the offshore energy regulation, as well as a guidance document for application processes. The main elements of the proposals were:

- A system for prequalification of market players;
- Subdivision of the opened areas, and subsequent announcement of invitation to apply in the respective subdivided areas;
- Award of exclusive rights to develop projects based on auction as a main rule and on qualitative competition as an alternative – as determined by the Ministry;
- Commercial-term development of the offshore wind area Sørlige Nordsjø II. Sørlige Nordsjø II is located near the border with Denmark, not far from the Ekofisk field. No subsidies are foreseen to be given as the Ministry believes commercial development should be feasible with bottom-fixed installations; and
- Development of the offshore wind area Utsira Nord, with a Government sponsored support scheme. Utsira Nord sits south of Bergen and is expected to be constructed using floating turbines due to the considerable sea depth.

The Norwegian Government presented on 6 December 2022 their proposal for pre-qualification criteria and auction model for Sørlige Nordsjø II, aqualitative award criteria and a potential support model for the areas of Utsira Nord. The proposal has been on consultation, and the Government is currently assessing the received consultation responses.

Important aspects related to infrastructure development remain to be investigated. The point of departure in the 2019 Offshore Wind Regulation is that individual projects should include production radials, but a need for coordination and possible development of 'hybrid' cross-border interconnectors has been highlighted. In addition, the need for coordination between competing applicants is increased due to the vast interest among stakeholders. State-owned TSO Statnett will be appointed as operator of new grid infrastructure offshore.

Recent litigation and procedures

In recent years, a number of high-profile cases have been brought before Norwegian courts regarding energy related matters. Among these cases, environmental issues, mandatory guarantees, and investor protection have been subject to review by the courts and agencies.

The most significant cases are:

ACER, Parliament and the Constitution

When the Third Energy Package was included in the EEA Agreement, the agreed solution between the EU and the EFTA countries entailed that the EFTA Surveillance Authority (ESA) can issue orders to the independent Norwegian energy regulator NVE-RME, based on proposals from ACER. This setup has given rise to litigation.

Nei til EU, the anti-EU organisation alleges that Parliament used the wrong constitutional procedure when its consent was given. On 1 March 2021, following procedural dismissal by both the District Court and the Court of Appeal, the Norwegian Supreme Court decided that the courts should decide on the subject matter. The case was heard by Oslo District Court in Autumn 2021. The court ruled on the matter in November 2021 and found that the decision to include the Third Energy Package in the EEA Agreement was not in breach of the constitution. The decision has been appealed by the claimants.

The question of procedure and adoption by Parliament is primarily a question about interpretation of the Norwegian Constitution. The immediate effects on Norwegian energy law are likely to be limited. Despite this, the case has received substantial public attention.

Climate lawsuit

In line with international trends, Norwegian courts have faced their first major climate change case. Four non-governmental organisations ("NGOs") including Greenpeace and Nature and Youth have brought proceedings against the state, represented by the Ministry of Petroleum and Energy, claiming that the 23rd concession round awarding production licences on the Norwegian Continental Shelf ("NCS") was invalid.

A major line of argument for the NGOs have been that Section 112 of the Norwegian Constitution, which gives all citizens the right to a clean environment, effectively bars the Government from awarding new production licences on the scale that the 23rd round entails. On a subsidiary basis, the NGOs also invoked procedural errors; in particular related to the level of research and investigation of consequences before awarding the licences.

Following appeals from the NGOs, the Supreme Court ruled on the matter in a plenary decision in December 2020. Four judges dissented, but the majority, consisting of 11 judges, found that the awarding of licences was valid. The decision regarding the constitutional aspects was unanimous. The dissenting judges based their opinion on the subsidiary basis and found that the level of investigation was too limited. The minority focused in particular on the fact that the climatic consequences of final consumption of produced petroleum was not outlined and assessed prior to granting the licences.

The ruling contains interesting reservations with respect to the future processes related to the detailed plans for development and operation of fields and resources (the "PDO"). Notwithstanding that the awarding of production licences was valid, the Supreme Court (both fractions) go far in stating that the Government must take the environmental consequences of future consumption of the resources into consideration when dealing with the PDO. This is in some contrast to the practice to date and has become a matter of debate.

Following the Supreme Court's decision, the NGOs have petitioned the European Court of Human Rights to hear the case. The case was admitted by the European Court in January 2022. The state has petitioned the European Court to dismiss the case. The European Court has decided to postpone the proceedings of the climate lawsuit, pending the outcome of three other climate cases from Portugal, Switzerland, and France. The NGOs have not received any time frame indicating when the relevant cases will be decided, nor when the proceedings in the case will continue.

Opposition against onshore wind parks

During the last couple of years, there has been strong opposition against the development and construction of onshore wind parks in Norway.

Numerous demonstrations have been held both in Oslo and locally. Additionally, several lawsuits have been filed in order to delay and/or hinder the commencement of construction. Some of these have received sustained national attention and publicity.

Activists fear the effects on nature, on wildlife and on the local communities in the areas where the parks are being built. At the time of writing, activists have had limited impact on projects that have already been sanctioned by Norwegian authorities. However, it is reasonable to assume that the widespread opposition is having a significant chilling effect on new onshore projects.

ESA Complaint on petroleum tax incentives

In January 2021, the Norwegian Green Party filed a complaint against Norwegian authorities to the ESA regarding a tax package sanctioned by the Parliament in June 2020 to incentivise investments in the oil and gas sector. The complaint claimed that the tax incentives constitute illegal state aid.

The tax package was introduced as a temporary amendment to the Norwegian Petroleum Tax Act and provides for: (i) immediate deduction of investments in the special tax base (56%), (ii) an increase in the 'uplift' and (iii) a pay-out of the assessed value of any deficit and unused uplift for income years 2020 and 2021. The direct background for the tax incentives was the sudden drop in oil prices in the first half of 2020, and the objective of the incentives was to improve liquidity in the petroleum industry and make it easier for companies to implement their planned investments.

The Norwegian Ministry of Finance estimates that the amendments will collectively increase the liquidity of petroleum companies by an amount of around NOK100 billion for 2020 and 2021. The Ministry estimates that the proposal will eventually increase revenue by around NOK14 billion.

The scheme is temporary and applies to investment costs incurred by companies in 2020 and 2021, and to investments included in development plans (PDO/PIO) submitted by year-end 2021 and approved by year-end 2022, and up to start of production.

The case has several similarities with the complaint that the environmental organisation Bellona filed against Norwegian authorities with the ESA in 2017, claiming that the exploration costs refund scheme laid down in the Petroleum Tax Act constitutes illegal state aid. The ESA did not agree with Bellona and the complaint was rejected. One aspect distinguishing the current case is that the complaint has been filed not by an NGO but by the Green Party, which is represented in Parliament.

The deadline for the ESA to open a formal investigation was 25 January 2022. Many commentators believed that the ESA would probably decline the complaint, as the ESA discussed the Norwegian petroleum tax system in relation to fundamental state aid issues in the Bellona case. However, the petroleum tax system may come under pressure from the EU, and the European Green Deal. The Paris Agreement and developments in EU case law may set clearer boundaries for the Norwegian authorities' process and scope in the petroleum sector. ESA's preliminary conclusion of 28 May 2022 is that the oil companies that have benefited from the petroleum tax incentive have not received any support that violates the EEA Agreement's rules on state aid. The complainants have submitted additional information to ESA that can contribute to change their view on the legality of the state aid, and the case has not been closed.

Carbon capture and storage initiatives – the Longship project

Norway has significant experience with carbon capture and storage ("CCS") projects. CCS has been carried out on offshore oil and gas fields since the 1990s, as CO_2 has been extracted from the oil and gas production in the Sleipner and Snøhvit fields and reinjected into the reservoirs. Norwegian authorities have for many years supported CCS projects and technology development, including the TCM test centre at the Mongstad refinery.

A new milestone was reached in 2020 when the Government confirmed grants for the Longship project in the amount of NOK17 billion (€1.65 billion). The Longship project is a full-scale CCS project, which covers: (i) CO_2 capture (total 800,000 tonnes/year) from the Norcem cement factory and the Klemetsrud waste disposal facility; (ii) shipping of liquid CO_2 to onshore terminals on the Norwegian west coast and (iii) storage of CO_2 in subsea reservoirs. The storage part of the project is carried out by the Northern Lights consortium, which consists of Equinor, Shell, and Total Energies. CO_2 will be received from ships to the Northern Lights onshore terminal, from where it will be transported through a pipeline to an offshore subsea deposit where it will be permanently stored. Total storage capacity is 37.5 million tonnes of CO_2, with a potential total storage capacity of 125 million tonnes. The Northern Lights project can also receive and store third party volumes of CO_2 and is planned to be in operation from Q1 2024.

CCS is governed by the Regulation regarding transportation and storage of CO_2, which implements the CCS Directive. The Regulation governs the exploration and exploitation of undersea reservoirs for storage of CO_2 on the NCS. As undersea reservoirs are owned by the state, CCS activities on the NCS require permits. The first permit for storage was awarded to Equinor in 2019, providing the legal basis for storage services to be carried by the Northern Lights consortium.

Carbon taxation

Norwegian carbon taxation rests on two pillars: flat taxation, and emissions trading under the EU Emissions Trading System ""ETS""). The flat Norwegian carbon tax, applicable to roughly half of the Norwegian economy, is set to be substantially increased in the years leading up to 2030. For 2021, the tax is at 591NOK per tonne of CO_2.

Norway is fully integrated into the EU ETS and most of Norwegian industry is covered, including airline operators. Accordingly, most of the Norwegian economy is covered by either a flat carbon tax, the EU ETS or both.

High electricity prices in 2022

Norway saw particularly high electricity prices in all of 2022. This corresponded with high energy prices, both in the rest of Europe and globally. Norwegian consumers are accustomed to low electricity prices compared to most of Western Europe, therefore spikes in electricity prices have a tendency to result in considerable public debate of which the price effect of Norway's cross-border interconnectors is often the focal point. The Government launched in late 2021 a temporary electricity support package for consumers which covered 80% of the portion of the electricity price that exceeded 0.70 per kWh. The percentage increased to 90% in October to December 2022. The electricity support package has been extended and will apply also in 2023, and 80% of the electricity prices exceeding 0.70 kWh will be covered in January, February, and March, and increase to 90% in October, November, and December.

Overview of the legal and regulatory framework in Norway

A. Electricity

A.1 Industry structure

Nature of the market

Norway's domestic electricity production has historically been based almost entirely on hydropower, but wind power is playing an increasing role. Hydropower now accounts for about 88% of the energy mix.[1]

Under Section 2 of the Waterfall Rights Act,[2] only the state may acquire ownership of hydropower resources, unless the Norwegian Government ("Government") or Norwegian Parliament ("Parliament") have granted a specific concession. Such concessions have mainly been granted to public undertakings. Public undertakings are defined as undertakings where the Norwegian public sector directly or indirectly controls at least two thirds of the capital and shares, and which are organised in such a manner that genuine public ownership exists.[3] Consequently, large and medium scale hydropower in Norway is primarily publicly owned.

In recent years, significant wind power capacity has also been installed, to a large extent supported by the Swedish-Norwegian Electricity Certificate programme.[4] Onshore wind power now accounts for around 10% of the energy mix.[5]

The development of offshore wind in Norway has received significant attention. The Offshore Energy Act was enacted by the Parliament in 2010.[6] To date, activity has been limited but in June 2020 the Government formally opened two areas for offshore wind development. At the same time, the Government issued a regulation providing directions for developers with respect to the application processes.[7]

Further legislative steps were proposed in June 2021, and on 6 December 2022 the Government presented draft framework conditions for the award of licenses for offshore wind production. The proposal included pre-qualification criteria and an auction model for the Sørlige Nordsjø II area and qualitative award criteria and a potential support model for the Utsira Nord area. The Government aims to announce invitations for license application in 2023.

Electricity production from other energy sources, such as wind power, are not subject to the same ownership restrictions applicable to hydropower, and the ownership structure is more diverse, with significant private ownership.

Key market players

The largest Norwegian electricity producer is Statkraft,[8] which is a fully state-owned enterprise. Statkraft is the largest owner of Norwegian electricity generating capacity, with a total installed capacity of 14.4GW hydropower, 2GW wind power, and 1.3GW solar power in 2021. Statkraft is the largest producer of renewable energy in Europe and the second largest owner of capacity in the Nordic region, with the Swedish state-owned company Vattenfall being the largest. A significant number of local municipalities and county authorities own generating capacity, mostly exercised through ownership interests in public undertakings. Among the most notable market players are Hafslund ECO, BKK, Agder Energi, and Lyse. In addition, privately owned (in the context of the Waterfall Rights Act) Hydro is a significant producer.

Norway has three grid levels: the transmission grid, the regional grid, and the local distribution grid. The Norwegian transmission grid is operated by the wholly state-owned enterprise Statnett. The Norwegian state has designated Statnett as Transmission System Operator ("TSO"), with system responsibility under the Energy Act.[9] Statnett also owns the transmission grid. The transmission grid primarily consists of lines with a voltage ranging from 300kV to 420kV; however, some lines operating at 132kV are also included.

The regional and distribution grids are owned by a substantial number of companies. These companies are in turn owned mainly by county authorities and regional authorities. There has been significant consolidation among regional and distribution grid owners in recent years, entailing larger and more efficient companies.

Privately owned companies are more common within electricity trading than in other areas of the industry, although there are private companies in all parts of the resource chain.

The state's interest in Statnett is held by the Ministry of Petroleum and Energy ("MPE"); the state's interest in Statkraft is held by the Ministry of Trade, and Fisheries ("MTF"). Consequently, the structure of public ownership in Statnett and Statkraft complied from the outset with the full ownership unbundling requirements of the Third Electricity Directive. This was made clear by Article 9(6) of the Third Electricity Directive, which states that two separate public bodies are not deemed the same entity.

Regulatory authorities

Regulatory responsibility and supervision within the electricity sector is largely delegated from the MPE to the Norwegian Water Resources and Energy Directorate ("NVE"). This includes activities such as granting concessions, in the first instance, for the building and operation of electricity production plants[10] and grid infrastructure, and the setting of overall grid tariff levels ("Income Frames"). In order to comply with the Third Electricity Directive's requirement for an independent national regulatory authority ("NRA"), the Norwegian Energy Regulatory Authority ("NVE-RME"), has been established within the NVE.[11]

Legal framework

The Energy Act is the backbone of Norwegian electricity market regulation, covering all parts of the resource chain from electricity production to consumption.[12] With the adoption of the act in 1990, genuine competition became a central aim and organising principle for the Norwegian electrical energy sector.

The Energy Act is a framework act, which, among other things, sets out the following:

- the general concession requirements for local area licences for the construction of distribution grids;
- construction and operating licences for other installations, including power stations and transmission grids; and
- trading licences applicable to monopoly grid operators as well as electricity producers and traders, marketplace licences, and import and export licences.

The key group of licences are the trading licences that provide, among other things, the authority to govern grid company operations and tariffs as further set out in the regulations that accompany the Energy Act.[13] As of 1 July 2021, import and export licences are only granted to projects where the TSO (ie Statnett) has a controlling interest.

Implementation of EU electricity directives

The Parliament approved the inclusion of the EEA-relevant parts of the Third Energy Package to the EEA Agreement in the spring of 2018.[14] In the years prior to the formal inclusion of these parts, Norway made changes to its legislation aimed at fulfilling many of the new requirements entailed in the package. These provisions entered into force in November 2019.

A.2 Third party access regime

Regional and distribution grid companies operate the grid under a trading licence.[15] The objective of this licensing regime is to facilitate an efficient electricity market and effective operation, utilisation, and development of the grid.[16] The licence requirements for grid operators include conditions concerning organisation, non-discriminatory market access, impartial behaviour, and the calculation of tariffs.[17] In this respect, licensees must ensure market access for all customers who want grid services at non-discriminatory and objective point tariffs and terms.[18]

Distribution grid companies with local area licences are at the outset required to ensure that customers within their grid area are supplied with electricity from their grid.[19] Grid companies are also required, if necessary, to invest in new grids in order to connect to new production or supply facilities.[20] Grid companies may be exempted from the investment obligation in electricity production facilities if the grid investment is not considered to be socio-economically efficient, but an exemption from the investment obligation in new supply will only be granted in extraordinary cases. On the production side, the investment obligation is likely to be of greatest practical significance for new small-scale renewable production facilities where project financing of a separate production grid may be difficult to obtain.

A.3 Market design

The Norwegian electricity market is part of the European market coupling.[21] The Nordic market is highly interconnected, and there is also interconnection capacity to the Netherlands, Germany, and the UK.

The Norwegian electricity sector is characterised by a liberalised end-consumer market, an advanced (and interconnected) wholesale market, a detailed regulation of natural monopolies such as grid services and tariff levels (point to point tariffs and regulator set income frames) and a strict licensing regime for activities such as construction, ownership, operation, and trading. There are no feed-in tariffs or capacity markets (apart from the balancing power market, which provides an operating reserve capacity).

There is a strong focus on security of supply, efficient production of renewables, integration with European energy markets, and a more efficient and climate-friendly use of energy.

These instruments and objectives are laid down in the Energy Act and its subsidiary regulations. In addition, the Planning and Building Act,[22] the Greenhouse Gas Emissions Trading Act,[23] and the El-Certificate Act,[24] as well as the different support schemes, all play important roles in the Norwegian energy policy that drives the market design.

A.4 Tariff regulation

Grid tariffs are set by the grid operators on the basis of yearly Income Frames determined by the regulator, NVE-RME. The overall principles for the determination of Income Frames are that the grid revenues, over a period of time, will cover the costs of operation and depreciation of the grid while giving a reasonable rate of return on invested capital, assuming efficient operation, utilisation and development of the grid.[25]

The stipulation of point tariffs for individual customers (ie tariffs referring to the customer's connection point to the grid that are independent of power purchase and/or sales agreements) must be non-discriminatory and objective.[26] Further requirements to this effect are provided in part five of the Control Regulation.[27]

A.5 Market entry

Licences are required for construction, ownership, and operation of power producing facilities, as well as for trading and transportation of electricity. Section 3-1 of the Energy Act sets out the licence requirements for the construction, ownership, or operation of electrical installations such as electricity generation and transmission facilities. Electricity distribution grids are in practice governed by a separate area licence requirement under Section 3-2 of the Energy Act. The Planning and Building Act sets out requirements for construction projects, including impact assessment requirements including environmental impact assessments,[28] as well as other requirements.

Ownership of hydropower resources over a certain potential capacity threshold (in practice large and medium scale hydropower production) is subject to specific restrictions under the Waterfall Rights Act (see ection A.1 above). Consequently, foreign, and private market participants cannot be granted such hydropower licences and may only participate in their capacity as minority shareholders in Norwegian public companies.

Similar restrictions do not apply to other production sources such as wind power.

Trading licences must be obtained by companies trading electricity in their own name. The process for obtaining a trading licence for a trading company is standardised, and applications may be filed online to the regulator, NVE-RME. Holders of trading licences in Norway include producers, grid companies, and trading companies as well as integrated companies performing several of these services.

A.6 Public service obligations, smart metering, and electric vehicles

Public service obligations (PSOs)

No particular public service obligations apply to specific producers and suppliers in Norway; a possible exception being that the TSO, Statnett, may instruct market participants, typically larger producers, to provide regulating capacity at cost plus a reasonable rate of return. With respect to grid companies, Statnett is subject to a number of obligations in its role as TSO with system responsibility. Distribution System Operators ("DSOs") are also subject to a number of obligations. The obligations of the TSO and DSOs to a large extent correspond to the tasks appointed to these grid operators under the Third Electricity Directive.

Smart metering

Grid companies were obliged to install advanced metering systems at all measuring points within their licensing area by 1 January 2019.[29]

Electric vehicles

Relative to the size of the population, the Norwegian market for electrical vehicles ("EVs") is one of the largest in the world. For years, Norway has granted substantial tax breaks for electrical cars, including an exemption from sales tax (25%) and from various other environmental taxes. Furthermore, owners of electrical cars have benefited from free parking, free passage on toll roads, and low electricity prices.

A.7 Cross-border interconnectors

Ownership in cross-border interconnectors for electricity has been a matter of debate for several years. In 2016, the Energy Act was amended to open for private ownership in such infrastructure, –ie a possibility for 'merchant lines'. As a result of compromises in the process leading up to implementation of the Third Energy Package, this possibility has been reversed. On 31 May 2021, the Parliament enacted the reversal, entailing that only the TSO (or companies controlled by the TSO) may be granted a licence for owning and operating cross-border interconnectors.

An exemption was made for possible hybrid interconnectors that may be constructed in connection with the future development of offshore wind on the Norwegian continental shelf ("NCS"). Such infrastructure may be owned by private parties, but Statnett as TSO will also have system operation responsibilities for hybrid connections.

The amended Energy Act entered into force on 1 July 2021. However, projects that had already applied for a licence under the former regime will still be handled under the regime in force at the time of the application. This has practical importance for the North Connect project (a consortium planning to build an interconnector from Western Norway to Scotland) and was as such part of the political debate.

Cross-border interconnector capacity from Norway to and from the other Nordic countries today amounts to a total of about 5.5GW. In addition, the NorNed cable to the Netherlands accounts for 700MW and the NordLink Cable to Germany for 1.4GW. Further, the North Sea Link interconnector between Norway and the UK became operational on 1 October 2021.

Oil and gas

B.1 Industry structure

Oil

Nature of the market

Crude oil from the NCS is partly refined in Norway and partly exported abroad. Crude oil is transported either by pipelines, or by shuttle tankers.

For a description of the Norwegian upstream licensing regime, an overview of key market players, the national regulatory authority, key legislative, regulatory, and contractual features see section E below.

Gas

Nature of the market

Despite being an important producer of gas, Norway exports around 95% of its gas resources from the NCS through the Gassled offshore transportation system. For further details, see section B.2 below.[30] Only insignificant quantities of gas are transported onshore for domestic use.

As the Norwegian domestic downstream gas market is very limited, it was considered an emergent market under the Second Gas Directive and therefore subject to minimal regulation. Following the implementation of the Third Energy Package into Norwegian law, the Norwegian regulations were amended to introduce requirements set out in the Third Gas Directive and New Gas Regulation. The impact of the Third Energy Package requirements are, however, limited as the provisions are principally aimed towards more mature gas markets.

There is no domestic gas transmission system in Norway. There are, however, two gas pipeline distribution networks in western Norway providing gas to private homes and local businesses. In addition, natural gas is available for domestic use at the five gas landing processing facilities in Norway, where natural gas is used both in the production of methanol and for power stations producing power and heat.

During the last decade, a new domestic market for distribution of liquefied natural gas ("LNG") in Norway has emerged, where LNG is used as fuel for ships and heavy transport and for thermal industry. The only Norwegian facility converting gas to LNG on a large scale is the LNG facility at Melkøya, and all LNG distributors are small-scale operators.

Key market players

Due to the limited domestic use of gas, there are few market players in the domestic natural gas market in Norway.

There are two DSOs for natural gas. The gas pipeline distribution network at Haugalandet is operated by private-owned Gasnor, which is a dedicated natural gas company. The network in Jæren and Ryfylke is operated by Lyse Neo, which is part of the public owned Lyse group, an industrial group operating within different fields of energy.[31]

The Nyhamna, Kollsnes, and Kårstø gas landing processing facilities are operated by Gassco, which is the operator of the Gassled transportation system. For further details, see section B.2 below. The facilities at Melkøya and Tjeldbergodden are operated by Equinor.

Regulatory authorities

The Third Gas Directive's requirement for an independent NRA is carried out through the establishment of the NVE-RME in the same manner as for the electricity sector. For further details, see section A.1 above.

Legal framework

The domestic gas market is governed by the Natural Gas Act[32] and the Natural Gas Regulation,[33] setting out provisions on the independent regulator, appointment of system operators, third party access to pipeline systems, and unbundling requirements.

However, Norwegian authorities have concluded that the current Norwegian downstream gas market does not include transmission systems, LNG distribution, natural gas storage facilities, or LNG storage facilities within the meaning set out in the New Gas Regulation and these provisions will be of limited relevance to the current Norwegian natural gas market.[34]

Implementation of EU gas directives

As for the electricity sector, the Third Energy Package regulations for the gas sector were implemented into Norwegian law in 2018 and entered into force in November 2019 (see also section A.1).

B.2 Third party access regime to gas transportation networks

The Natural Gas Act and the Natural Gas Regulation provide the basis for both negotiated and regulated access to domestic gas systems (if any). The NRA will, by individual decisions, decide on tariffs and other conditions for granting access to distribution networks, transmission networks, and LNG facilities.

The NRA may in regulations provide conditions for TPA to storage facilities and storage in pipelines. Where a TSO or a DSO provides balancing services, the NRA will by individual decision approve or determine conditions for such services or approve or determine the method to be used when deciding on the terms and conditions for such services.

Access to the Norwegian upstream pipeline system (Gassled) is regulated by the MPE, through the Petroleum Act,[35] and the Petroleum Regulation,[36] which follow the principles of TPA set out in the upstream pipeline system provision of the Third Gas Directive. Natural gas undertakings and eligible customers that can substantiate a reasonable need for transportation (ie shippers) are entitled to access the system on objective and non-discriminatory conditions.

Gassled is organised as a joint venture and was historically owned by the shippers of natural gas from the NCS. The independent system operator Gassco, which is a fully state-owned company that is not a shareholder in Gassled, exercises its operator duties under the provisions of the Petroleum Act and in accordance with an operator agreement with Gassled. This includes operating the access regime, which consists of a primary and a secondary market. In the primary market, the shippers reserve capacity through Gassco, which can be transferred to others in the secondary market.

B.3 LNG terminals and storage facilities

In Norway, domestic gas consumption is limited, and there are only a few small-scale facilities for receiving LNG, which are located on the Norwegian west coast. The Melkøya LNG facility, located in Hammerfest in northern Norway, is a full-scale facility for the exportation of LNG, which processes gas from the Snøhvit field in the Barents Sea.

The Norwegian downstream natural gas market does not include LNG storage facilities within the definition in the New Gas Regulation. There is no onshore gas storage in Norway, except some storage facilities at the Kårstø gas processing facility.

Upstream LNG facilities fall within the Petroleum Act and follow the same regulatory regime as other petroleum activities.

B.4 Tariff regulation

Section 6 of the Natural Gas Act provides the basis for the approval of tariffs, and for further regulations on tariffs for access to and use of downstream natural gas and LNG infrastructure have been enacted.

The transportation (and/or processing) of natural gas within the Gassled upstream transportation system is regulated by a standard agreement entered into between Gassco (on behalf of Gassled) and the shipper. The tariff is regulated in a separate Tariff Regulation[37] and is payable on a ship-or-pay basis. The tariffs consist of a capital and an operating element,[38] and the transportation system is divided into different zones, with separate tariffs applying for each zone.

B.5 Market entry

Under the Natural Gas Act and the Natural Gas Regulation, a licence is required for construction and operation of facilities for transfer of natural gas, LNG facilities, and other facilities for supplying natural gas to natural gas undertakings in other region(s). Smaller facilities for the transfer of natural gas and LNG and small-scale distribution of natural gas are exempted from the licence requirement. The licence is awarded based on transparent and non-discriminatory criteria. The authorities may stipulate conditions relating to applicants' qualifications, such as organisational model and competence, technical aspects, emergency preparedness, choice of route, tie-in to other facilities, and so on.[39]

For a company to be eligible for the award of a production licence in the Norwegian upstream sector, it must fulfil certain criteria regarding technical competence, organisational requirements, and financial strength. In practice, it is required that the licensee is incorporated and registered in Norway. While the award of licences is subject to the principles set out in the Licensing Directive,[40] the authorities will, when considering whether a company shall be awarded a production licence(s), take into account the particular features of the application in question, such as the applicant's proposed work obligations. The final award is subject to negotiations with the authorities.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

As the consumer market for gas in Norway is very limited, no comprehensive public service obligations apply.

Smart metering

As the consumer market for gas in Norway is very limited, smart metering for gas consumption has not been introduced.

B.7 Cross-border interconnectors

There are no downstream cross-border interconnectors for natural gas in Norway

The Norwegian upstream natural gas transportation system is complex, with several interconnections and export pipelines. There are currently seven major pipelines transporting natural gas from the NCS to the UK and continental Europe, ie the Vesterled pipeline, the Langeled pipeline, the Franpipe pipeline, the Zeepipe pipeline, the Norpipe pipeline, and the Europipe I and II pipelines. Norwegian gas is also transported to the UK through the Flags pipeline. All of these pipelines collectively comprise the Gassled upstream transportation system. For a description of access regime and tariffs, see sections B.2 and B.4 above.

C. Energy trading

C.1 Electricity trading

Physical trading

Norway has long been part of a joint Nordic power market and participates today in EU Market Coupling for both day-ahead and intraday markets. Pending the implementation of the capacity allocation and capacity management ("CACM") regulation in Norwegian law,[41] the Energy Act has been amended in order to ensure such market coupling. The CACM regulation enters into force 1 August 2021.

In Norway, electricity is traded both bilaterally and on regulated marketplaces. In the Norwegian bilateral market, trades must be executed within the same price area, and market participants mainly use the industry standards from the EFET and the Nordic Association of Energy Traders ("NAET").

As for organised trading, power exchanges must obtain a separate Norwegian licence in order to operate in Norway. The Nordic power exchange Nord Pool was until recently the only market operator for electricity trading in Norway, having *de facto* monopoly for trading in both day-ahead and intraday markets. EPEX Spot was however granted a licence as market operator with effect from 1 June 2019. When the CACM regulation enters into force in Norwegian law, market operators will need a designation as a Nominated Electricity Market Operator ("NEMO") in order to operate in Norway, and existing NEMOs may rely on their passporting rights.

The Norwegian balancing market is operated by the TSO Statnett, and consists of primary reserves (FCR), secondary reserves (FRR-A), and tertiary reserves (FRR-M). The primary and secondary reserves are automatic regulating functions, whereas the tertiary reserves consist of a regulating power market (RK) and a regulating power options market (RKOM) for balancing purposes. In the regulating market, participants bid for regulating power, and the options market shall ensure future bids for a fee paid by Statnett.

Financial trading

Financial trading is organised by the power derivative exchange Nasdaq Oslo ASA, which is designated as a regulated market under the Securities Trading Act.[42] Through the brand name Nasdaq European Commodities, the exchange provides trading and clearing services for Nordic and European power derivatives, thereby providing price hedging possibilities for participants also engaged in physical trade, as well as trading opportunities for participants solely engaged in financial transactions.[43]

In addition to the organised trading arranged by Nasdaq Commodities, significant bilateral trade takes place. Parts of the market are broker-driven, and parts are comprised of directly negotiated trades. In addition to originated contracts, various standard contracts are being utilised, including the ISDA Master Agreements, the EFET Financial energy master agreement, and the 'FEMA' NAET standard financial contract.

C.2 Gas trading

Gas produced on the NCS is the property of the respective licensees, who are obligated to market, transport and sell their gas; the exception being that the equity gas of the State's Direct Financial Interest ("SDFI") is marketed and sold by Equinor together with its own equity gas. Gas sales are carried out by the individual licensees on a bilateral basis.

Gas trading is primarily carried out on a physical basis. Historically, gas was usually sold on long-term take-or-pay contracts; however, today, gas volumes are increasingly being sold on short-term contracts. Most of the long-term contracts are based on price formulae that are linked to the price of alternative sources of energy. There has, however, also been a tendency towards increased use of gas indices in long-term contracts. Short-term contracts are typically entered into on the basis of market standards such as the National Balancing Point ("NBP"), Zeebrugge Trading Point ("ZBT") and EFET contracts.

Licensees must submit to the authorities, on a quarterly basis, information regarding their gas delivery obligations, including information on volume profiles and main contractual terms. As there is no gas hub trading taking place in Norway, there is no downstream balancing regime as such. In the upstream sector, Gassco is responsible for balancing the inlet and outlet of natural gas and maintaining necessary pressure in the Gassled transportation system. To use the upstream transportation system, shippers need to reserve capacity with Gassco. Apart from providing the volume information as required under the access regime (see section B.2), no particular notification requirements apply with regard to contractual volumes.

D. Nuclear energy

There is no nuclear energy generation in Norway.

E. Upstream

The Parliament is the ultimate authority for the regulation of petroleum activities on the NCS. The overall responsibility for ensuring that petroleum activities are carried out in accordance with the regulatory framework rests with the MPE, whereas the responsibility for following up detailed regulation on resource management and HSE lies with the Norwegian Petroleum Directorate ("NPD") and the Petroleum Safety Authority ("PSA").[44] Policy and legislation concerning petroleum taxation is handled by the Ministry of Finance ("MOF"), and annual tax assessments are carried out by the Oil Taxation Office.

The legal basis for governmental regulation of the petroleum sector is found in the Petroleum Act, which provides the legal framework for the licensing system. The legal basis for taxation of offshore petroleum activities is the Petroleum Taxation Act.[45]

In addition to the high-level provisions in the Petroleum Act, offshore petroleum activities in Norway are subject to a very comprehensive system of regulations and approvals. This includes the Petroleum Regulation, which mainly addresses resource management, and the HSE Regulations,[46] which address the health, safety, and environmental aspects of the activities. Generally, the HSE Regulations are function-based and risk-based, leaving it up to the licensees to choose how to fulfil the requirements. The Norwegian system also implies a 'see-to' duty (*påse-plikt*), imposing on licensees a duty to ensure that all of their contractors and subcontractors comply with applicable regulations.

The level of state participation in the Norwegian oil and gas industry is high. The Norwegian state is the largest player on the NCS by way of its shareholdings in Equinor, and through the SDFI, whereby the state participates directly in various production licences.[47]

The Norwegian petroleum licensing system comprises various licences, approvals, mandatory agreements, and other mechanisms.

The production licence is the core document in the licensing system and gives the licensee an exclusive right to explore for, develop, and produce petroleum in the block(s) covered by the licence. Production licences are normally awarded through annual licensing rounds. In addition, all unlicensed acreage in the mature North Sea area is open for application in annual award procedures, a process known as APA (Awards in Predefined Areas). Companies can apply for licence awards individually or in groups.

The production licence can be awarded to one or several oil companies. To become licensees, companies must fulfil certain criteria particularly regarding technical qualifications, organisational requirements, and financial strength. The MPE offers a pre-qualification procedure that outlines these criteria in order to facilitate the application preparations of prospective licensees. The same criteria will apply to a prospective assignee of a production licence interest or of the shares in a company holding licence interests. Transfers of a licence interest and transfers of shares in a company holding a licence interest are subject to approval by the MPE and MOF.[48]

The company appointed as operator by the MPE becomes responsible for executing the day-to-day management of the petroleum activities on behalf of the licensees. In addition to fulfilling the general requirements for all licensees, the operator must have the additional capabilities necessary to carry out the day-to-day activities of the licence group. No particular corporate structure requirements apply, although in practice most licensees are set up as Norwegian limited companies. The qualifications of the operator will in practice vary with the developing stages of the licence, and stricter requirements will apply for operating a licence in the production phase than in the exploration phase. Transfer of operatorship is subject to governmental approval, and the same requirements will apply to the prospective new operator.

The production licence is awarded for an initial period (which may be up to ten years). Within this period, a specified work obligation must be fulfilled, which is often an obligation to procure seismic data and to drill an exploration well. Following fulfilment of the specified work, the duration of the licence is normally extended. An area fee also applies after the initial period, based on the size of the licence acreage. If the work obligation is not fulfilled within the stated time limit, the licence will generally be revoked. A licence can also be withdrawn as a result of serious or repeated violations of the Petroleum Act, such as those pertaining to regulations or licence conditions.

If a licensee wishes to grant security over a production licence interest to finance its activities associated with the licence, the consent of the MPE is required, which is regularly given. The MPE can also in certain cases consent to allow the financing to include activities under a licence other than the one which is mortgaged. The possibility for extending the purpose of financing was originally meant to be limited; however, such consent has in practice been granted quite often.

One of the conditions of the award of the production licence is that the licensees enter into a joint operating agreement ("JOA") in a standard format prepared by the MPE. The JOA governs the relationship between the licensees, forming the basis for day-to-day management of the activities, allocation of costs, decision making processes, and other processes. All petroleum produced is allocated to the licensees in accordance with their participating interest.

To develop a petroleum discovery, the licence partners must submit a plan for development and operation ("PDO") to the authorities. The PDO sets out, among other things, the development solution, estimated development costs and a production profile for the deposit.[49]

Based on the PDO, the NPD issues annual production permits that allow the licensees to produce defined volumes of petroleum. The export of petroleum is not subject to a specific legal regime as such.

The licensees must also submit a plan for decommissioning and cessation of the petroleum activities to the MPE. The MPE then decides, based on the plan, on the disposal of the facilities. In relation to the transfer of the production licence interest, the transferor will remain secondarily liable to the remaining licensees for the share of the decommissioning costs associated with the transferred licence interest. This requirement, which was introduced in 2009, has in practice affected the market for licence share transactions, as assignors will regularly demand additional security from the assignee in order to be held harmless for such potential secondary liability. Since 2017, a standard guarantee requirement applies to corporate transactions, creating a similar secondary liability for decommissioning costs for companies selling shares in licensee companies. Contractually, such secondary liability is usually structured around a decommissioning security agreement or through alternative mechanisms in the sale and purchase agreement.

Construction and operation of transportation and/or processing facilities is subject to a plan for installation and operation ("PIO"), which must be submitted to the MPE for approval.[50]

Gas is transported to Europe via the Gassled transportation system, as described in section B.2 above. Crude oil is transported onshore for refining via ships and independent pipelines.

For companies engaged in oil and gas operations on the NCS, there are two partially overlapping income tax regimes, ie ordinary income tax imposed by the general rules in the General Tax Act,[51] and the special petroleum tax on income imposed by the Petroleum Taxation Act. As a result, the total marginal income tax rate for companies engaged in exploration and production activities on the NCS is 78%, consisting of a 22% general income tax and a 56% special petroleum tax to the state.

Gross income generated by oil sales is assessed according to a norm price system, where sales prices are fixed by an administrative body, whereas income generated by gas sales is assessed on actual sale prices. A licensee on the NCS that is subject to Norwegian taxation will be entitled to tax deductions against income taxed at 78% with regard to exploration and production costs (running expenses, net financial items, depreciations, and uplift) and transportation costs (tariff payments). Production installations depreciate over six years, and an uplift is granted on a special tax basis for a four-year period for investments in production and pipeline facilities. The uplift is 5.5% per year.

In 2021, a temporary amendment to the Norwegian Petroleum Tax Act was introduced which implies (i) immediate deduction of investments in the special tax base (56%); (ii) an increase in the 'uplift'; and (iii) that pay-out of the assessed value of any deficit and unused uplift for income years 2020 and 2021 could be claimed. The scheme applied to investment costs incurred by licensees in 2020 and 2021, and to investments included in development plans (PDO/PIO) submitted by year-end 2021 and approved by year-end 2022, and up to start of production.

An exploration refund scheme was introduced in 2005, whereby companies not entitled to deductions can annually claim a refund from the state of the tax value of direct and indirect costs. This is with the exception of financial charges incurred in the course of exploration for petroleum resources.[52] The tax value is currently 78%. The refund will reduce in correspondence with the tax loss carried forward.

F. Renewable energy

F.1 Renewable energy

The use of energy in Norway is characterised by broad access to renewable energy sources ("RES") such as hydropower, wind power, and bioenergy. Electricity production in Norway is almost exclusively based on these sources, and the majority of non-renewable resources such as oil and gas are exported out of the country.

Norwegian law includes provisions implementing the 2009 ERS Directive and the Amended Fuel and ERS Directive. The target of increasing the total share of gross domestic energy consumption from renewables to 67.5% by 2020 was met already in 2014, and in 2019 the RES share was as high as 74.62%.[53] The recast ERS Directive adopted as a part of the Clean Energy Package has, however, not yet been incorporated into the EEA agreement.

To promote new electricity production based on RES, Norway and Sweden have had a common system for electricity certificates since 2012. The system is a market-based support scheme and is regulated by the Electricity Certificate Act.[54] Producers will receive one certificate per MWh of renewable electricity that is generated for a period of 15 years, whereas electricity suppliers and certain consumers have a statutory duty to buy electricity certificates. The joint target of 28.4TWh of new RES production was reached in 2019, and Norway, although not Sweden, will not issue any certificates after 2021. The duty to buy certificates will gradually be phased out until it is annulled in 2036.

The production of wind power in Norway has increased substantially over the last years. In 2020, 15 new wind power farms started operating, and wind power production peaked at an all-time high of 9.9TWh – an 80% increase compared to the year before.[55] Of particular importance is Europe's largest onshore wind farm project, situated in the Fosen area north of Trondheim, with a peak effect of 1057MW.[56] There is also significant interest in the development of offshore wind projects, see section A.1. The increase in wind power must be seen in light of the considerable investments made to date; in 2019 the value of total investment was as high as NOK9.7 billion.[57]

From 1 January 2023, an excise duty of NOK 0.02 kWh applies to power produced from all onshore wind farms. The Norwegian Government proposed on 28 September 2022 to introduce a resource rent tax on onshore wind power and proposed an effective resource rent tax of 40%. It is proposed that the resource rent obligation should apply to onshore wind farms subject to licensing under the Energy Act, ie, wind farms with more than 5 turbines or a total installed capacity of 1 MW or more. In addition, it was announced that an excise duty on electricity will be introduced on prices exceeding NOK 0.70 kWh. The proposal is currently on public consultation.

The focus on RES in Norway is wide-ranging. In addition to hydro power and wind power, public and private parties initiate development and improvement of solar energy, thermal energy, wave power etc. An important factor is that the large oil companies operating in Norway are shifting towards more renewable solutions, decarbonising their upstream activity, and investing in production and development of RES.

F.2 Renewable pre-qualifications

There are no pre-qualification criteria for renewables.

F.3 Biofuel

Chapter 3 of the Product Regulation[58] sets out the biofuel requirements in Norway, and includes requirements for blending, requirements for sustainable cultivation of raw material, reduced emissions of greenhouse gas ("GHG") requirements, and sustainability criteria for biofuels and liquid biofuels. The Product Regulation implements the Biofuel Directive, the Amended Fuel and ERS Directive, the Fuel Quality Directive, and Inland Waterway Vessels Directive.

The required share of biofuel for road transport increases every year. As of 1 January 2021, the sales requirement of biofuel for road transport is set to 24.5%, with an additional requirement that 9% of all such biofuels must be produced from waste, residues, non-food cellulosic material, and lingo-cellulosic material (advanced biofuel). In 2020, biofuel requirements were introduced for the aviation industry, requiring that at least 0.5% of fuel used in the industry must be advanced biofuel. Distributors of biofuel must report on the fulfilment of sustainability criteria.

As the use of biofuels has increased in Norway, the previously available exemption from payment of Norwegian road tax on fuel charges was repealed on 1 July 2020, and accordingly biofuels are now subject to this duty.[59]

G. Climate change and sustainability

G.1 Climate change initiatives

Norwegian climate policy is built on the Parliament's 2008 and 2012 all-party agreements on climate matters. Norway has adhered to several international agreements on climate action, which continue to influence Norwegian efforts and policies. This includes the Paris Agreement and the UN targets for sustainability. In addition, pursuant to the 2019 climate agreement between Norway, Iceland, and the EU, whereby the parties agreed to extend their cooperation to reduce greenhouse gas emissions by at least 40% by 2030 compared to 1990 levels, Norway participates in the EU's 2030 climate and energy framework.[60]

In 2018, the Climate Change Act[61] was adopted, establishing binding climate targets, and promoting public discussion on the topic. The climate policy is further set out in several white papers from the Government, with the Climate Plan for 2021-2030 being the most recent.[62] Several public bodies also considered different measures in a report on climate treatment (*Norw. Klimakur 2030*) published in January 2020.[63]

Norway increased its emission reduction targets in 2021, with the aim of reducing the level of GHG emission from 1990 by at least 50% to 55% by 2030, and 90% to 95% by 2050.[64] The targets will mainly be met through the use of the EU Emissions Trading System ("EU ETS") and other carbon taxation, regulatory measures, climate-related requirements in public procurement processes, information on climate-friendly options, financial support for the development of new technology, and initiatives to promote research and innovation. Despite the EU ETS and carbon taxation being the most important measures, the Climate Plan for 2021-2030 also focused on emissions not currently subject to allowances.

To leverage Norway's position as an energy exporting nation in the transition to become a low emission society, the Government has proposed new initiatives encompassing hydrogen, offshore wind, strengthening of the power grid, and facilitating a low emissions oil and gas sector. In the white paper of 11 June 2021, the Government presented an electrification strategy to provide a framework for making Norway greener.[65] The white paper also presented a roadmap for hydrogen, featuring specific ambitions for maritime hubs, industrial production, and multiple pilot projects to develop new and more cost-efficient solutions and technologies in Norway. The Government highlighted the Longship Carbon Capture and Storage ("CCS") project as an instrumental part of carbon dioxide ("CO_2") management and efficient climate action (see also section H.3 below).

G.2 Emission trading

In 2005, with the adoption of the Greenhouse Gas Emission Trading Act,[66] Norway introduced a national quota system for tradable allowances. The national quota system was merged with the EU ETS system in 2008, and Norwegian businesses trade and surrender EU Allowances when fulfilling their obligations under the GHG Emission Trading Act and supplementing Regulation.[67]

Being a part of the EEA, Norway must implement all changes in the EU ETS. The Revised EU ETS Directive setting out rules for phase IV (2021-2030) is incorporated into the EEA agreement, and the supplementing Commission Regulations have been implemented in Norwegian law to fully harmonise the legal framework.

The aviation industry is subject to both EU ETS and the Offsetting and Reduction Scheme ("CORSIA"). The CORSIA scheme is a market-based measure initiated by the International Civil Aviation Organisation (ICAO), and Norway is currently participating, on a voluntary basis, in the pilot phase (2021-2023).

Norway also participates in the project-based mechanisms under the Kyoto-protocol. The Norwegian Environmental Agency is the contact point for such mechanisms.

G.3 Carbon pricing

In addition to the EU ETS and national emissions quotas as described under section G.2, Norway imposes taxes on GHG emissions from specific activities. On 8 January 2021, the Government presented a White Paper announcing a gradual increase in the carbon tax rate from its current level of about NOK590 to NOK2,000 per tonne of CO_2 equivalents in 2030. To ensure that the overall level of taxation is not increased, the Government proposed that any tax increase is offset by reducing other taxes correspondingly.

The carbon tax applies to import and domestic production of mineral oil, petrol, natural gas, and LNG, and to emissions of CO_2 and other GHGs which emanate from upstream oil and gas activities.

G.4 Capacity markets

There is no capacity markets regime in Norway comparable to the UK capacity markets regime.

H. Energy transition

H.1 Overview

As Norway is significant as an oil and gas producing country, there is much focus on transitioning the traditional oil and gas sector to a more future-oriented sector. In this regard, carbon capture and electrification of upstream oil and gas activities are important initiatives.

H.2 Renewable fuels

Hydrogen

In June 2020, the Government presented its overall hydrogen strategy. The strategy includes a review of hydrogen as a potential fuel alternative, as well as the commercial and technical prerequisites for production, storage, distribution, and use of hydrogen.[68] The strategy was supplemented on 11 June 2021 with a 'roadmap for hydrogen', setting out more specific goals and policy instruments.[69] The roadmap must be considered by the Parliament before any initiatives are implemented.

The vision for 2050 is that the market for the production and use of hydrogen in Norway will be well established, with hydrogen being used as an industry input factor, as fuel for ships and vessels and for heavy vehicles on land.

The roadmap sets out short-term (2025) and mid-term (2030) ambitions to be achieved through cooperation between the public and private sectors. The short-term ambitions focus on the maritime sector, including production facilities for blue hydrogen, and pilots for developing and demonstrating new technology, while the mid-term ambitions focus on the logistics, full-scale production of blue hydrogen with CCS, and market opportunities in Europe for produced hydrogen.

The roadmap further outlines the policy instruments to be applied by the MPE to support the ambitions, including instruments such as increased carbon pricing, support schemes, and green public procurement. There is also a proposal for establishing a research centre for hydrogen and ammonia. Interestingly, the roadmap includes initiatives to apply Contracts for Difference (CfDs) to support the realisation of large-scale production of hydrogen.

In February 2021, Yara, Statkraft, and Aker Horizons announced that they intend to establish Europe's first large-scale green ammonia project in Herøya, targeting green hydrogen and green ammonia opportunities within shipping, agriculture and industrial applications.[70] Blue hydrogen solutions require capture and storage of CO_2 from natural gas. In December 2020, Horisont Energi announced that it would cooperate with Equinor for the development of a blue ammonia production plant in Finnmark, Norway's northernmost county. The project is based on the supply of natural gas from the Barents Sea and access to CO_2 storage under the seabed.

Ammonia

Ammonia as a hydrogen-based solution is addressed in the hydrogen strategy (see section A) and plays an important role in the transition to hydrogen-based solutions, especially as fuel for bulk carriers and tankers.

H.3 Carbon capture and storage

Norway has a long history of demonstrating secure storage of CO_2 in the offshore environment. The Sleipner CO_2 Storage Project has been in operation for 25 years, and the Snøhvit CO_2 Storage Project was launched in 2008. These two projects are the only operative CCS projects in Europe and have contributed to the storage of millions of tonnes of CO_2.

In September 2020, the Government presented a white paper on the full-scale CCS demonstration of Project Longship.[71]

Project Longship covers CO_2 capture from two pilot facilities, shipping of liquid CO_2 to the onshore terminal on the Norwegian west coast and storage of CO_2 in subsea reservoirs. The project was approved by the Parliament in the state budget for 2021, and the total investments amount to NOK21.5 billion. The investments will be shared by the Norwegian state and the industry.[72]

The Government has also initiated and participated in a number of activities through the state-owned company Gassnova, which was established in 2005 to further the development of technologies and knowledge related to CCS. Gassnova administers the national research and financing program CLIMIT and is the majority shareholder of Technology Centre Mongstad (TCM), the world's largest test facility for CO_2 capture technology. Gassnova also coordinates the Longshi project.

CCS activities require storage permits and are regulated by the CO_2 Storage Regulation,[73] the Pollution Control Regulation,[74] and the Petroleum Act and Regulation, implementing the CCS Directive and accommodating international guidelines and commitments.

H.4 Oil and gas platform electrification

There are currently 16 fields that have or are expected to have approved plans to introduce power from shore, and it is expected that all such solutions will be operational in 2023.[75] This electrification will lower the emission volume with an estimated 3.2 million tonnes of CO_2 per year, corresponding to about a quarter of total petroleum sector emissions in 2019. For the Johan Sverdrup field, which is the third largest oil field on the NCS and has been in production since 2019, the operator has reported that one barrel of oil produced at Sverdrup emitted 0.17kg of CO_2 in the first year – almost 100 times lower CO_2 emissions than the global average (measured in kg of CO_2 per barrel produced).[76] This is mainly due to power from shore.

Offshore wind turbines may also deliver power to oil and gas platforms. However, as such platforms are dependent on stable power, this will only become a supplement to other power sources. When completed, the floating offshore wind park Hywind Tampen will deliver electricity to the platforms Snorre A and Gullfaks A.[77] The profitability of this will be dependent on the costs for backup power supply, infrastructure, gas prices, and carbon pricing.

The electrification of oil and gas fields has been a controversial political issue in Norway in recent years.

H.5 Industrial hubs

There are several hubs and clusters that contribute to the Norwegian energy transition.

The Norwegian industrial sector has over the last few decades been subject to major changes as important industrial plants have been shut down or transformed. In cities where industry used to be the backbone of society, industrial parks focusing on new technology and developments have been established, and local companies are working together with public bodies as well as large corporations with strong financial resources. Industrial parks may also receive funding from state-owned Enova. Mo Industrial Park in Mo i Rana and Herøya Industrial Park in Porsgrunn are two examples of large industrial parks that focus on green industry.

Hubs and clusters can also be admitted to the Norwegian Innovation Clusters ("NIC") programme, which is a national, state-funded cluster programme focusing on economic growth through sustainable innovation.[78] The programme was founded in 2002 and consists of three levels. The first level, Arena, is a three-year programme offering financial and educational support. The second-level, Arena Pro, takes place over five years, focusing more on coordination and execution of development projects. The third-level, Global Centers of Expertise (GCE), is ten-year programme for world leading clusters with growth potential in international markets. In addition, clusters with leading companies may adhere to the brand name Norwegian Centers of Expertise (NCE). In 2021, the NIC programme covered 39 clusters with a budget of NOK217 million.[79]

H.6 Smart cities in Norway

The Government defines a 'smart city' as a city that uses digital technology to make it a better place to live, reside, and work, and that pursues improvement of public services, its citizens' quality of life, the optimal use of public resources, productivity increase and reduction of climate and environmental changes.[80]

In 2019, the Government examined the scope and extent of smart cities in Norway.[81] The results showed that there were between 30 and 50 Norwegian municipalities that worked in various ways on creating smarter cities, and that the number would increase considerably over the next few years. The main Norwegian cities are all making considerable efforts to achieve these smart city goals. As the 2019 Eco Capital of Europe, Oslo is at the forefront of European smart city development, with initiatives such as electric buses and zero-emission construction sites. Stavanger was named Norway's smartest city in 2019, and the CityxChange project for Trondheim is part of the EU Horizon 2020 programme.

The development of smart cities is carried out by the local authorities, as previous proposals for preparing a national strategy were voted down in the Parliament. It is therefore the municipalities themselves that decide on initiatives, organisation, funding etc. Many municipalities participate in national or Nordic networks, both public and private, which organise events, develop roadmaps, and facilitate cooperation between municipalities and relevant parties.

I. Environmental, social and governance (ESG)

Generally, ESG issues have had the effect of reducing investments in oil and gas related industries, while increasing investment in the RES industries. Although oil and gas investments are affected by several global, regional, and local events, ESG-related issues are among the most important factors. Many investors are shying away from non-renewable industries due to several reasons, including ESG policy developments, public opinion on issues such as climate change, and new corporate policies of lenders. ESG issues have likely also contributed to the reduced investments in oil services businesses such as drilling and seismic services.

In parallel, investors' interest in RES industries such as offshore wind and hydrogen, and in CCS related industries, has increased dramatically. The Government is expected to initiate an auction process for the award of areas for offshore wind production, and this is already attracting significant interest from a wide array of industrial players.

Endnotes

1. See www.energifaktanorge.no/en/norsk-energiforsyning/kraftproduksjon.
2. Act of 14 December 1917 No. 16.
3. The Waterfall Rights Act, see in particular Sections 5 and 2.
4. See www.publikasjoner.nve.no/diverse/2020/elsertifikat2020engelsk.pdf.
5. Ref note 1.
6. Act 4 June 2010 No. 21 on renewable energy production offshore.
7. Regulation 12 June 2020 No. 1192 on renewable energy production offshore.
8. Formally its fully owned subsidiary Statkraft Energi AS.
9. Act 29 June 1990 No. 50 section 6(1). See also the appurtenant Regulation 7 May 2002 No. 448 concerning system responsibility in the power system.
10. This does not include licences for acquisition of hydropower resources under the Waterfall Rights Act.
11. Cf. Act 25 May 2018 No. 21 Section 2-3.
12. See section 1(1) of the Act.
13. The more specific provisions relating to market operation follow from regulations to the Energy Act, including the Energy Regulation of 7 December 1990 No. 959, which is a Royal Degree, and subordinate regulations such as the Control Regulation of 11 March 1999 No. 302, the Electricity Supply and Grid Services Regulation of 11 March 1999 No. 301 and the Regulation on grid operations and the electricity market of 24 October 2019 No. 1413. Other important regulatory instruments relevant to the electricity market include the Waterfall Rights Act and the Watercourse Regulation Act of 14 December 1917 No. 17 (both for hydropower development), the Planning and Building Act and the Competition Act of 5 March 2004 No. 12.
14. Directives 2009/72/EC and 2009/73/EC and Regulations (EC) 713/2009, (EC) 714/2009 and (EC) 715/2009.
15. Awarded under Section 4-1 Energy Act.
16. Section 4-1 Energy Regulation.
17. Section 4-1 Energy Act and Chapter 4 of the Energy Regulation.
18. Section 4-1(2) (2) Energy Act and Section 4-4(d) of the Energy Regulation.
19. Section 3-3 Energy Act.
20. Section 3-4 Energy Act.
21. On 18 June 2021, the Norwegian Parliament enacted the implementation of four of the Third Package delegated regulations (Network Codes) into Norwegian law. The guidelines on capacity allocation and capacity management (CACM), electricity balancing (EB), forward capacity allocation (FCA) and system operation (SOGL) will therefore formally entered into force in Norway on 1 August 2018. Norwegian law is however on some fields already accommodating to such guidelines to ensure a functioning market coupling with EU countries.
22. Act of 27 June 2008 No. 71.

23. Act of 17 December 2004 No. 99.
24. Act of 24 June 2011 No. 39.
25. Section 4-4(b) Energy Regulation. More detailed provisions on how to achieve this result are given in the appurtenant Control Regulation.
26. Section 4-1(2)(2) Energy Act and section 4-4(d) Energy Regulation.
27. Regulation on economic and technical reporting, income frame for grid operations and tariffs of 11 March 1999 No. 302.
28. Act 27 June 2008 No. 71. See also section 2-1 Energy Act.
29. Cf. Section 4-5 Regulation 3 November 1999 No. 301.
30. See www.norskpetroleum.no/produksjon-og-eksport/eksport-av-olje-og-gass.
31. The distribution networks are described in the consultation paper for implementing the Third Energy Package into the Natural Gas Regulation from December 2018. Available at www.regjeringen.no/contentassets/b746bf6f404b4d7cbd4e54918e4631a0/horingsnotat-naturgassforskriften-l999482.pdf.
32. Act 28 June 2002 No. 61.
33. Regulation14 November 2003 No. 1342.
34. Regulation (EC) No. 715/2009 cf. Preparatory works Prop. 6 L (2017-2018) amendments to the Norwegian Natural Gas Act (Third Energy Package), p.12.
35. Act 29 November 1996 No. 72.
36. Regulation 27 June 1997 No. 653.
37. Regulations 20 December 2002 No. 1724.
38. The capital element is stipulated by the MPE and will give the investors about 7% interest on the invested capital before tax. The operating element is cost based and laid down by the operator.
39. Sections 2-3 and 2-4 Regulations 14 November 2003 No. 1342.
40. Directive 94/22/EC.
41. Regulation (EU) 2015/1222 on capacity allocation and congestion management. The CACM regulation was implemented on 21 June 2021.
42. Act 29 June 2007 No. 75.
43. See further NASDAQ Commodities' web pages, available at www.nasdaq.com/solutions/european-commodities
44. The main functions of the NPD relate to resource management while the responsibilities of the PSA relate to issues regarding health, safety and environment.
45. Act 13 June 1975 No. 35.
46. The Framework Regulations (Regulation 12 February 2010 No. 158), the Management Regulations (Regulation 29 April 2010 No. 611), the Facilities Regulations (Regulation 29 April 2010 No. 634), the Activities Regulations (Regulation 29 April 2010 No. 613), and the Technical and Operational Regulations (Regulation 29 April 2010 No. 612).
47. The SDFI is managed by the state-owned company Petoro AS.
48. The tax effects of a transaction are normally approved by default pursuant to Regulation 1 July 2009 No. 956.
49. The PDO must be approved by the MPE, and must also be presented to Stortinget if the estimated investment is more than NOK20 billion.
50. A PIO is not required if the facilities are already covered by a PDO.
51. Act 26 March 1999 No. 14.
52. Section 3(c)(5) of the Petroleum Taxation Act.
53. See www.eea.europa.eu/data-and-maps/indicators/renewable-gross-final-energy-consumption-5/assessment.
54. Act 24 June 2011 No. 39.
55. See www.nve.no/energi/energisystem/vindkraft.
56. See www.fosenvind.no/vindparkene.
57. See www.ssb.no/energi-og-industri/artikler-og-publikasjoner/rekordhoye-vindkraftinvesteringer-i-2019.
58. Regulation 1 June 2004 No. 922.
59. Regulation 11 December 2001 No. 1451 on excise duties.
60. See www.ec.europa.eu/clima/news/european-union-iceland-and-norway-agree-deepen-their-cooperation-climate-action_en.
61. Act 16 June 2017 No. 60.
62. Meld. St. 13 (2020-2021) – White paper – Norway's Climate Action Plan, see www.regjeringen.no/en/aktuelt/heilskapeleg-plan-for-a-na-klimamalet/id2827600.
63. See www.miljodirektoratet.no/globalassets/publikasjoner/m1625/m1625.pdf.
64. Sections 3 and 4 of the Climate Change Act.
65. Meld. St. 36 (2020-2021) White Paper - Putting Energy to Work, see www.regjeringen.no/en/aktuelt/regjeringen-legger-frem-stortingsmelding-om-verdiskaping-fra-norske-energiressurser/id2860271.
66. Act 17 December 2004 No. 99.
67. Regulation 23 December 2004 No. 1851.
68. The Norwegian Government's hydrogen strategy, available at www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/regjeringens-hydrogenstrategi.pdf.
69. Included in Meld. St. 36 (2020-2021) White Paper - Putting Energy to Work.
70. See www.yara.com/news-and-media/green-ammonia-project-press-conference.
71. See www.regjeringen.no/en/dokumenter/meld.-st.-33-20192020/id2765361.
72. See www.regjeringen.no/en/topics/energy/carbon-capture-and-storage/id86982.
73. Regulation of 12 December 2014 No. 1517.
74. Regulation of 1 June 2004 No. 931.
75. Power from shore – rapport, available at www.npd.no/globalassets/1-npd/publikasjoner/rapporter/2020/kraft-fra-land-til-norsk-sokkel/power-from-shore-to-the-norwegian-shelf-report-summary-2020.pdf.
76. See www.equinor.com/en/what-we-do/johan-sverdrup.html.
77. See www.equinor.com/en/what-we-do/hywind-tampen.html.
78. Meld. St. 27 (2015-2016) White paper – Digital agenda for Norway in brief. See www.regjeringen.no/en/dokumenter/digital-agenda-for-norway-in-brief/id2499897.
79. Available at www.regjeringen.no/contentassets/d6fa05005d5d4ea3a45f62286c2ba2fe/kartlegging_av_smarte_byer.pdf.

Energy law in Poland

Recent developments in the Polish energy market

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Poland still relies mostly on fossil fuels to meet its energy needs. Decarbonisation targets adopted by the European Union are highly discussed in Poland, as phasing out coal and lignite would have a great impact on society in the regions of the country where mines and coal or lignite power plants are significant employers. However, in the last three years a number of changes (both on the market and within the regulatory environment) could be observed, pointing towards a less carbon-heavy future of the Polish energy mix. In 2021 the government adopted the Polish Energy Policy until 2040, indicating that by 2030, the share of coal in electricity generation will be reduced to 56%, the renewable energy in gross energy consumption will be at the level of 21%-23% and the CO_2 emissions will be reduced by 30%. These goals are to be achieved, among others, by the introduction of offshore wind in 2025 and nuclear energy in 2033.

Offshore wind

To date, there are no operational offshore wind farms ("OWF") in the Polish exclusive economic zone on the Baltic Sea. First permits for artificial islands construction and maintenance ("OWF location permit"), which are initial permits in the offshore wind farm development process, were issued in 2012. However, none of the projects covered by these permits has reached the construction phase yet. Until 2021, the development of offshore wind farms was regulated as any other renewable energy installation development, without consideration of the challenges connected with the offshore location of the projects. There was also no support system dedicated specifically for this technology. In 2021, the Act on Promoting the Generation of Electricity in Offshore Wind Farms ("Offshore Wind Act") entered into force. The Offshore Wind Act provides for a number of solutions aimed at facilitating the implementation of this technology in Poland. First and foremost, a dedicated support system for offshore wind farms was introduced, in the form similar to a contract for difference ("CfD") mechanism. The support is granted in two phases, the first of which is the non-competitive phase of the system[1], which finished in mid-2021. Support was granted by way of administrative decision of the National Regulatory Authority ("NRA"), on a first-come-first-served basis, to the following investors: Baltic Trade and Invest sp. z o.o. (member of the RWE capital group), Elektrownia Wiatrowa Baltica – 2 sp. z o.o. and Elektrownia Wiatrowa Baltica – 3 sp. z o.o. (both being joint-ventures of members of the PGE and Ørsted capital groups), MFW Bałtyk 2 sp. z o.o. and MFW Bałtyk 3 sp. z o.o. (both being joint-ventures of members of the Polenergia and Equinor capital groups), Baltic Power sp. z o.o. (joint venture of members of the Orlen and Northland Power capital groups) and C-Wind sp. z o.o. (subsidiary of Engie S.A.'s' and EDP Renewables S.A.'s' joint-venture). The level of support for each of the projects will be subject to the European Commission's' approval. The total installed capacity of the projects granted the aid in the first phase is 5.9GW.

The second phase of the scheme will begin in 2025. Offshore wind farms will participate in auctions for the award of the support (also in a CfD-like form), on the 'project versus project' basis (the Polish government does not develop the sites and the investors who secured OWF location permits in various parts of the Baltic Sea will compete for financial support). Projects with a total installed capacity of at least 5GW are to be granted support in this phase.

To participate in the auctions, the projects have to secure the OWF location permit. The procedure for its issuance is competitive. If there are at least two interested applicants for a given location, the applications are graded in accordance with criteria provided for in the Offshore Wind Act and secondary legislation to it, and the one which scores the highest number of points wins. The support can be granted only to offshore wind farms located in specific areas of the Baltic Sea, therefore the competition is fierce.

Apart from the support system, the Offshore Wind Act envisages several amendments of the general rules of the investment process (for example different rules on the geological surveys), which take into account the maritime location of the projects, and rules on offshore wind farms safety were introduced. Additionally, the investors who wish to participate in the support system are obliged to prepare a supply chain plan. The plans are a source of information for the government on the envisaged and actual impact of the offshore wind farm projects on the country's economy (however there are no sanctions for non-performance of the plan, the investors have to inform the government on the plan execution and explain reasons for deviations). Public versions of the plans are published by the NRA so that entrepreneurs interested in providing materials and services to the offshore wind sector can assess their potential and prepare for cooperation with the project developers.[2]

Nuclear power

Poland does not have a nuclear power plant. Talks about its construction are a recurring topic over the last 40 years (initiated in 1982 and abandoned after a few years). However, in 2020, the government adopted an updated 'Polish Nuclear Power Programme'[3]. The programme's objective is the construction and commissioning of large-scale nuclear power plants with a total installed capacity from about 6GW to about 9GW, the first power plant is to be commissioned in 2033 and the second in 2039.

In December 2021, the location of the first power plant was announced as the site named "Lubiatowo-Kopalino" in the Choczewo commune.[4]

The Polish industrial sector is also considering developing small modular reactors ("SMR")." In the second half of 2021, a few co-operations in this field were announced. KGHM Polska Miedź (a mining group active mainly in the copper mining sector) signed a co-operation agreement with NuScale Power (US-based SMRs developer). Synthos Green Energy (a member of the Synthos capital group, a chemical company specialising mainly in synthetic rubbers, latexes and styrene plastics) signed an agreement with PKN Orlen (one of the leading companies in the Polish energy sector), aimed at the development of GE Hitachi Nuclear Energy's BWRX-300 reactors[5]. The said companies have already submitted requests to Atomic Energy Agency regarding reactors technology assessment (to be issued in 2023). It is claimed that the first SMR is to start operations in 2029.

PV uptake

In the recent years, there has been a significant increase in the number of photovoltaic ("PV")installations commissioned in Poland. The boost has been observed in both sectors: professional (where the projects are developed by specialised entities, with the intent to produce electricity for sale) and consumer (where PV installations are developed for self-consumption). It has been observed that the use of solar energy between 2017 and 2021 show a steady increase. In 2021, the total consumption of this energy was 516.5% higher compared to 2017[6]. Only in 2021, 3.8 GW of PV capacity were installed with a 56% growth compared to 2020[7], which placed Poland at 10th place (only EU country) in the top 10 solar PV markets worldwide. The upswing is attributed to favourable prosumers[8], however, the commercial PV sector is also flourishing. Based on the data for 2021, installed capacity of PV has the biggest share in RES market in Poland, with 44,9%, whereas wind takes second place with 42,2%[9]. Despite the positive trend in PV development, investors are now faced with a new constraint, as the limited grid capacity causes the system operators to deny grid connection (not only for PV installations, but for other types of renewables as well). This turns investors towards initiating dispute resolution cases before the NRA (if they do not deem denial of connection sufficiently justified) and seeking solutions for more efficient use of existing capacity (eg combining existing wind farms with PV).

ORLEN's mergers

PKN Orlen S.A. is a leading multi-energy corporation, currently with 49,90% of shares owned by the State Treasury. Following *inter alia* the 2020 merger with Grupa Energa (core activities: electricity generation, distribution and sales), as well as the merger with Grupa LOTOS (core activities: crude oil exploration, extraction processing, and petroleum products distribution) finalised in 2022, PKN Orlen is on the way to finalize a merger with PGNiG Grupa Kapitałowa (core activities: natural gas exploration, production, import, storage, sales, distribution).

Price caps for electricity

Due to the unusual and volatile situation in the commodity markets (coal and gas), the legislator decided to introduce a number of solutions to protect eligible consumers (mainly households) from rising electricity costs in 2023. Consequently, the Act of 7 October 2022 on special solutions protecting electricity consumers in 2023 ("Act on special solutions")[10] and the Act of 27 October 2022 on emergency measures to limit electricity prices and support certain consumers in 2023 ("Act on emergency measures")[11] were enacted. First of the abovementioned acts "freezes" the prices for household consumers at the level of prices from 2022 for the consumption volume up to 2 MWh annually (in certain cases, eg large families or people with disabilities, up to 2,6 MWh or 3 MWh annually). The second act provides for a so-called "maximum price" for electricity for the eligible recipients indicated in this Act: household consumers (in regard to the volume exceeding the consumption limit of 2MWh or 2,6 MWh or 3 MWh annually indicated in the Act on special solutions) small and medium-sized enterprises, local government units and municipal enterprises, health care institutions, various units providing social and educational assistance, educational and higher education institutions, cultural institutions, public benefit organisations, trade unions, fire brigades, and animal shelters. The solutions adopted for the protection of the aforementioned groups assume that in settlements with those groups a "maximum price" is applied at the level of:

- 693 PLN/MWh – for household consumers.
- 785 PLN/MWh – for the remaining groups (eg public utility customers and small and medium-sized enterprises).

According to the Act, energy suppliers are entitled to compensation for the application of the maximum price of electricity.

Additionally, the Act on emergency measures provides details of the mechanism implementing the revenue cap indicated in the Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices[12]. The mechanism has a form of the collection of a mandatory levy payable to the Fund managed by Zarządca Rozliczeń S.A. by electricity producers (with an installed capacity above 1 MW with the use of energy from wind, solar, geothermal, hydropower, biomass and bioliquids, waste, lignite and hard coal, liquid fuels and gaseous fuels) and trading companies. The rules for calculating the deduction for the Fund are included in the Act and the accompanying resolution of the Council of Ministers of 8 November 2022[13] (amended with resolution of the Council of Ministers o 9 December 2022)[14].

Price caps for gas

On 21 December 2022, the Act on Special Protection of Gas Fuel Consumers in 2023[15] came into force. According to the new regulations, from 1 January to 31 December 2023, gas sellers will be obliged to apply a maximum price of PLN 200.17/ MWh in settlements with selected final consumers, such as households, housing communities, health care institutions, various units providing social and educational assistance, educational and higher education institutions, cultural institutions, public benefit organisations, trade unions, fire brigades, animal shelters etc. In addition, the aforementioned groups of customers will pay a fee for distribution services at the level resulting from the tariff approved by the President of the ERO for the distribution system operator for 2022.

According to the Act, gas suppliers and gas distribution system operators are entitled to compensation for the application of the maximum price of gas or distribution fees.

The Act also provides for the introduction of a 'gas allowance', ie a VAT refund for households using a gas heater as the main source of heat, which is registered or reported in the Central Register of Building Emissions It will be available to:

- a one-person household, where the average monthly income does not exceed PLN 2,100,
- a multi-person household, where the average monthly income does not exceed PLN 1,500 per person.

Additionally, the Act introduces a mechanism analogous to the one included in the Act on emergency measures – a mandatory levy to the Fund managed by Zarządca Rozliczeń S.A. The levy is payable by companies mining gas. The rules for calculating the deduction for the Fund are included in the Act and the accompanying resolution of the Council of Ministers of 30 December 2022[16].

Please note that the Act refers to the Council Regulation (EU) 2022/1854 of 6 October 2022 on an emergency intervention to address high energy prices, however the method of calculating the mandatory levy does not correspond with the method of calculating the temporary solidarity contribution defined in the Council Regulation.

Developments in hydrogen sector

The Act on Special Protection of Gas Fuel Consumers in 2023 also provides for changes in the operation of the hydrogen sector. The main changes are as follows:

- dropping the requirement for daily hydrogen testing flow and instead introducing an obligation to ensure that an additional test is performed when production exceeds 50 in 30 days;
- introduction of sanctions for hydrogen traders without a hydrogen quality certificate (fines of between PLN 50,000 and PLN 500,000);
- introduction of simplifications in the implementation of obligations relating to the confirmation of the quality of hydrogen produced in the case of production of hydrogen by electrolysis and the installation of analysers for the flow test of hydrogen quality which enables continuous control of the quality of hydrogen with respect to the majority of the required parameters;
- introduction of a transitional provision allowing hydrogen producers to use laboratories that are not accredited for hydrogen testing until the end of 2024, provided that they are accredited for fuel quality testing and that they apply the hydrogen quality testing standards set out in the executive regulations to the Act of 25 August 2006 on the system of monitoring and controlling fuel quality[17].

Removal of power exchange trade obligation

On 21 November 2022, the Polish government published the Act of 29 September 2022 amending the Energy Law and the Renewable Energy Sources Act, which entered into force 6 December. The Act abolished the currently existing regulations which obliged electricity producers to sell electricity generated by them on the power exchange. Regulations before 21 November 2022 included a catalogue of exceptions to this obligation, for example energy generated from renewable energy sources. As such, the amendment is mainly dedicated to producers of energy from conventional sources.

With the abolition of the exchange obligation, each market participant will be able to independently decide on the chosen trading method according to its own market strategy. As a result, all market forms of trading will be available for electricity from sources so far covered by the exchange obligation.

Moreover, the Government introduced changes aimed at lowering the gas trade obligation. In accordance with the Regulation the minister for climate and environment of 21 December 2022 on the determination of the volume of high-methane natural gas injected into the transmission network in 2022 and in 2023, the power exchange obligation for natural gas will be no less than 30% in 2022 and 2023. Effectively, the level of the obligation was lowered from no less than 55%.

Endnotes

1. For more information on the reasons for non-competitive mechanism being implemented please see the European Commission decision on Polish offshore wind support scheme acceptance (case SA.55940, C(2021) 3436 final).
2. Seven such plans were published to date (in Polish), available at www.ure.gov.pl/pl/oze/mfw/plany.
3. See www.gov.pl/attachment/4cddd10a-5e8b-414d-bb95-670f6507d73e.
4. See www.ppej.pl/en/news/preferred-site-of-the-first-polish-nuclear-power-plant-indicated-by-investor.
5. See www.orlen.pl/en/about-the-company/media/press-releases/2021/december/orlen-steps-up-efforts-to-deploy-small-nuclear-reactors.
6. Energia ze źródeł odnawialnych w 2021 r., Główny Urząd Statystyczny, Warszawa 2022, p. 39.
7. SolarPower Europe, *The EU Market Outlook for Solar Power 2022-2026*, p.15. www.api.solarpowereurope.org/uploads/Solar_Power_Europe_Global_Market_Outlook_report_2022_2022_V2_07aa98200a.pdf
8. *Ibidem*. In 2022 legislation changing rules on prosumerism settlement has entered into force. It was adopted partially in order to curb the escalation of new connections.
9. Energia ze źródeł odnawialnych w 2021 r., Główny Urząd Statystyczny, Warszawa 2022, p. 56.
10. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002127
11. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002243
12. See www.eur-lex.europa.eu/legal-content/PL/TXT/?uri=CELEX:32022R1854
13. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002284
14. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002631
15. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002687
16. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20220002868
17. See www.isap.sejm.gov.pl/isap.nsf/DocDetails.xsp?id=WDU20061691200

Overview of the legal and regulatory framework in Poland

A. Electricity

A.1 Industry structure

Nature of the market

The wholesale electricity market is liberalised. On the retail market, prices for household consumers are still regulated, however, in 2015 the national regulatory authority ("NRA") lifted the obligation to submit tariffs for approval in regard to all major incumbent electricity retailers in Poland. As a consequence, offers to consumers by such retailers may include deregulated prices (lower than the prices contained in approved tariffs).

On 21 November 2022, the Polish government published the Act of 29 September 2022 amending the Energy Law and the Renewable Energy Sources Act, which entered into force 6 December. The Act abolished the regulations which obliged electricity producers to sell electricity generated by them on the power exchange. Therefore, each market participant is able to independently decide on the chosen trading method according to its own market strategy.

The Herfindahl-Hirschman Index ("HHI")" in the electricity generation sector published by the NRA for 2021 amounted to 1,370.6 (when calculated on the basis of installed capacity) and 2.198,9 (when calculated on the basis of electricity output).[1]

Key market players

PSE Operator SA ("PSE")" (a joint-stock company) is the Polish transmission system operator ("TSO")," for which a full ownership unbundling ("FOU")" model has been implemented. Under the Polish legal framework, only one TSO can be appointed to the Polish market and it has to be a fully state-owned company.

An independent system operator ("ISO")" model applies to the Polish DSOs. There are five major distribution system operators ("DSOs")" (connected directly to the transmission system): PGE Dystrybucja SA, Tauron Dystrybucja SA, ENEA Operator sp. z o.o., ENERGA-Operator SA and Stoen Operator sp. z o.o ("Innogy")."[2] All are part of large Polish vertically integrated companies except for Innogy which operates the distribution system in the capital city of Warsaw.

With regards to power generation, the key players belong to the following capital groups: PGE Polska Grupa Energetyczna, TAURON Polska Energia, ENEA and Orlen[3]. The largest traders are PGE Obrót SA, Tauron Sprzedaż sp. z o.o., ENEA S.A. and ENERGA-OBRÓT S.A.

In 2020, PKN Orlen S.A. obtained 80% of shares in ENERGA S.A., the parent company of the ENERGA capital group, effectively taking over control of the capital group.

Regulatory authorities

Matters of energy policy are in the hands of the Ministry of Climate and Environment, whose responsibilities include the preparation and implementation of the national energy policy (including energy security and the energy mix), issuing secondary legislative acts in the field of energy, and participating in international cooperation in the field of energy.

The whole Polish energy market (electricity, gas and heat) is regulated by the President of the Energy Industry Regulatory Authority (*Prezes Urzędu Regulacji Energetyki*), which is the Polish NRA. The President is appointed by the Prime Minister and can only be dismissed before the expiration of the term of office as set out in the relevant legislation. The responsibilities and powers of the Energy Authority include the granting and withdrawing of licences, approving tariffs and grid codes, controlling customer service quality standards, checking compliance with quality standards, resolving disputes in relation to energy enterprises that refuse to contract electricity or connect to the grid (otherwise than as required to do so) and imposing fines. The regulator also has the power to designate the TSO and DSOs.

Most of the abovementioned companies dealing with the generation, trading and distribution of electricity are directly or indirectly owned by the State Treasury. The Government Agent for Strategic Energy Infrastructure (*Pełnomocnik Rządu do spraw Strategicznej Infrastruktury Energetycznej*), appointed by the Prime Minister, oversees the TSO; the Minister of State Assets oversees other energy entities in which the State Treasury has shares, including trading and generation companies.

Legal framework

The regulatory framework for the electricity market is set out in the Energy Law Act of 10 April 1997 (as amended). This act regulates the electricity market and the markets for gas and municipal heating.

The law does not provide for a template of the contracts for electricity sale, distribution and transmission, however the Energy Law Act indicates the basic elements which have to be included in such agreements. In addition, grid operators and electricity sellers (see below) must prepare tariff proposals for their services, reflecting the underlying costs, and is subject to the regulatory approval.

A licence granted by the NRA is required for conducting the following activities:

- electricity generation, exclusive of generation of electricity from certain sources or under certain thresholds;

- electricity storage in storage units of total installed capacity above 10MW;
- electricity transmission and distribution;
- electricity trading and sale, exclusive of trade conducted by certain entities.

The licence can be granted only to entities that have their seat or residence in the territory of a member state of the European Union, the Swiss Confederation, a member state of the European Free Trade Association (EFTA), a party to the agreement on the European Economic Area (EEA), or Turkey. Licence applicants must meet a number of conditions listed in the Energy Law Act by showing good financials, as well as the technical and organisational ability to conduct the licenced activity. The NRA provides a list of standard documents needed in the licencing procedure on its website.[4]

Implementation of EU electricity directives

The Third Electricity Directive was fully implemented in 2013 through the Energy Law Act and a number of statutory instruments. The most important of these statutory instruments include the Minister of Energy Regulation of 4 May 2007 on the detailed conditions of the functioning of the electric power system, and the Minister of Energy Regulation of 6 March 2019 on detailed rules for tariff-setting and calculation and settlements in electricity trade.

Implementation of the recast Electricity Directive and recast Electricity Regulation is ongoing. The most recent amendment of the Energy Law Act introduced, among other things, provisions implementing the recast Electricity Directive solutions on electricity storage. A second major amendment, which is at an early stage of the legislative process (pre-parliamentary works), provides for, among other things, dynamic electricity price contracts, citizen energy communities and a 24-hour technical supplier switching process.

For renewable energy see section F.

A.2 Third party access regime

Polish law is in compliance with the third party access ("TPA")" rule.[5] Since the introduction of the TPA rule to the Polish electricity market (2007), 970,000 customers have switched suppliers (this includes 740,000 household customers).[6]

A.3 Market design

The Polish electricity market is regulated and partially liberalised, which means:

- a licence must be obtained to enter the market; and
- when already in the market, energy entities are required to, with an ever-growing scope of exemptions, submit electricity tariffs to the Energy Authority for approval.

In 2015, the President of the Energy Industry Regulatory Authority permitted all major incumbent electricity retailers in Poland to offer consumers deregulated prices lower than the prices contained in approved tariffs. This has significantly changed the market structure, despite the fact that electricity retailers are still formally obliged to apply approved tariffs when billing consumers (see section A.4).

A.4 Tariff regulation

Fees for transmission and distribution are regulated and, at least formally and with a number of exemptions, prices for consumers are regulated (see section A.1). The TSO and each DSO and electricity retailer must calculate and then submit to the Energy Authority for approval a draft tariff to be applied in the subsequent period (usually one year, but no longer than three years). In practice, the tariff approval process takes the form of negotiations between the NRA and the energy company. As a result, usually the final fees and prices are lower than proposed in the initial application for tariff approval.

Tariffs include fees or prices and other extensive provisions on billing, eg rules for qualification for different tariff groups.

A.5 Market entry

Market entry in Poland, as a rule, requires a licence, which is granted by the Energy Authority, providing that the entrant complies with a number of requirements under the Energy Law Act (see section A.1). In practice, the process of obtaining a licence takes a few months (depending on the type and size of activity, the corporate structure of the licensee's' capital group and so on). For some types of business in the energy sector (eg, generation in small renewable energy sources ("RES") installations) only a registration is required. No licence or permit from the Energy Authority is required to purchase shares in a licence holder.

Before one undertakes an activity in the field of electricity distribution, an additional administrative decision on appointing the DSO has to be issued by the NRA.

A.6. Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Polish energy law does not use the term 'public' service obligations' and there is no legislation dedicated specifically to any such obligations. However, some obligations of this nature are scattered over a range of legislative instruments. For example, operators must ensure a secure and regular supply, and generators must cooperate with operators and comply with their instructions to ensure a secure power supply. In addition, there are provisions for sellers of last resort.

Smart metering

The Energy Law Act does not use the notion of a 'smart' metering system', using the phrase 'remote reading meter' instead. However, it is likely these meters will fulfil the definition of the smart meter provided in the recast Electricity Directive (the secondary legislation on detailed technical qualities and functions of the remote reading meter has not yet been published, however it is indicated in the Energy Law Act itself that they will be sending and receiving data, including communicating with household appliances). The DSOs will be obliged to install remote reading meters in 80% of the metering points by 2028, in accordance with the schedule provided in the Energy Law Act.

As of January 10, 2023, more than 20% of energy consumption points have a remote reading meter installed. This exceeds the minimum goal scheduled for December 31, 2023 as prescribed in the Energy Law Act by five percentage points.

The energy market information system will be a centralised system that will process energy market information to facilitate energy market processes and facilitate information exchange between power system users. The TSO is the operator of the system. System users will be obliged to provide data to the system, as well as able to obtain data from it, to enable and facilitate various processes in the electricity market.

Electric vehicles

The Law of 11 January 2018 on Electromobility and Alternative Fuels implements the Directive on Alternative Fuels. The Law sets out rules for the development and operation of infrastructure for the use of electricity and alternative fuels in transport and defines basic terms such as charging point, charging station, electric vehicle ("EV")", alternative fuels and so on. The Law also provides various incentives for consumers to use EVs, including excise tax exemptions and permission to use bus lanes. Secondary legislation to the Law establishes technical requirements for the electricity charging and alternative fuels refuelling infrastructure.

A.7 Cross-border interconnectors

The Polish power system has the following cross-border interconnectors[7]:

- LitPol Link: Ełk-Alytus (Lithuania);
- SwePol: Słupsk Wierzbięcino -Storno (Sweden);
- Krajnik-Vierraden (Germany);
- Mikułowa-Hagenverder (Germany);
- Wielopole/Dobrzeń- Nosovice/Albrechtice (Czech Republic);
- Kopanina/Bujaków-Liskovec (Czech Republic);
- Krosno Iskrzynia-Lemesany (Slovakia);
- Rzeszów-Chmielnicka (Ukraine, works are underway to resume operations); and
- Zamość-Dobrotwór (Ukraine, allows only for electricity import).

The balance of cross-border exchanges totalled 820GWh in 2021.[8] As interconnectors are part of the transmission system, only the TSO can operate them. The Polish Energy Policy until 2040 provides for the construction of an underwater cable line between Poland and Lithuania (the Harmony Link) by 2025.

B. Oil and gas

B.1 Industry structure

Nature of the market

The Polish gas market is regulated for household consumers and will remain so until 2024. The market for industrial customers has, however, been deregulated since 2017. The deregulation was made possible as the obligation for gas traders to sell a certain proportion of the gas supplied to the national gas system on commodity exchanges[9], on either (i) a market organised by an entity operating a regulated market in the territory of the Republic of Poland or (ii) on an OTF operated by a company operating a commodity exchange, gave rise to greater market competition. The proportion covered by the obligation has gradually increased to reach 55%. The Energy Law Act provides for a number of exemptions from this obligation.

Poland meets its gas requirements from its own resources and by imports. In 2020, these imports amounted to 190,4TWh, whereas 40.7TWh was produced locally. Around 40TWh of the imported gas was delivered via an LNG terminal.[10] Gazprom stopped delivering natural gas via the Yamal-Europe pipeline in May 2022; the role of imports from countries other than Russia is increasing.

The Polish Energy Policy until 2040 envisages that Poland will become the hub for gas transmission and trade for the region, and a north-south gas corridor is to be constructed. under the 'Three' Seas Initiative'.

Key market players

Poland has one TSO, OGP Gaz-System SA, a joint-stock company 100% owned by the State Treasury. The Yamal transit pipeline crosses Poland and its Polish section belongs to EuRoPol Gaz SA, a company owned by PKN ORLEN S.A. and PAO Gazprom. OGP Gaz-System has been appointed an independent operator of the Yamal pipeline until December 6, 2068.

OGP Gaz-System operates the Polish coastal LNG terminal in Świnoujście.

The gas trading market is strongly dominated by the PGNiG capital group which in 2022 became a part of Orlen capital group (49.90% of shares are owned by the State Treasury). The parent company, PGNiG SA, sells gas to other gas trading companies and industrial customers (the wholesale market sales in 2020 executed by PGNiG amounted to 139,4 TWh, whereas other traders cumulatively sold 56,7TWh[11]); its subsidiary PGNiG Obrót Detaliczny sp. z o.o. sells gas to business and household retail customers (in 2021, the market share of this company exceeded 89%). The group also owns a distribution company, which covers virtually the whole area of Poland.

There are also several trading and distribution companies that are independent of PGNiG, such as EWE Energia sp. z o.o., G.EN Gaz Energia SA, Duon Dystrybucja SA, Polenergia Kogeneracja sp. z o.o., SIME Polska sp. z o.o., and Enesta sp. zo.o. All major electricity retailers also have gas in their product portfolio (see section A.1). For the high methane natural gas market, the HHI published by the NRA for 2020 amounted to 9,371.66[12].

PGNiG SA also owns all gas storage capacity in Poland. The storage facilities are operated by Gas Storage Poland sp. z o.o., a subsidiary company of PGNiG SA.

Regulatory authorities

The Minister of Climate and Environment is the chief government authority for energy policy and the President of the Energy Industry Authority is the main authority for energy (see section A.1).

Under the Energy Law Act, the Government Agent for Strategic Energy Infrastructure (*Pełnomocnik Rządu do spraw Strategicznej Infrastruktury Energetycznej*), appointed by the Prime Minister, oversees the TSO. Other energy entities of the State Treasury are overseen by the Minister of State Assets, including the major Polish gas trader(s).

Legal framework

The basic regulatory framework for the gas market is set out in the Energy Law Act of 10 April 1997 and in related secondary legislation, such as the Minister of Energy regulation of 15 March 2018 on the detailed rules for the formulation and calculation of tariffs and charges in the trading of fuels, and the Minister of Economy regulation of 2 July 2010 on the detailed conditions for the functioning of the gas system.

A licence granted by the NRA is needed for the following activities:

- gas storage (excluding storage of LNG in installations with capacity below 1MJ/s);
- liquefaction and regasification of natural gas in installations with capacity of at least 200m^3/h;
- gas transmission or distribution (excluding distribution in gas networks with capacity below 1MJ/s);
- gas trade and sale (excluding trade and sale of gas delivered to the LNG terminal, trade below certain thresholds or made by certain entities).

An additional administrative decision is needed to become a system operator.

Implementation of EU gas directives

The Third Gas Directive was fully implemented in 2013. A FOU model has been implemented for the gas TSO.

B.2 Third party access regime to gas transportation networks

Polish energy law is fully compliant with the third party access rule.[13]

B.3 LNG terminal and gas storage facilities

Poland has a coastal LNG terminal in Świnoujście, which is operated by OGP Gaz-System (see section B.1). The terminal was officially opened in October 2015 and the first commercial volumes of LNG were shipped to the terminal in June 2016. Since then, the volumes of LNG imported into Poland have been rising steadily, accelerating in 2022 to 57% year-on-year. OGP Gaz-System is working on further development of the terminal's' capacity and technical features. The Polish Energy Policy until 2040 envisages the construction of a floating storage regasification unit in the Gdansk Bay by 2025.

PGNiG SA is the owner of all gas storage facilities in Poland. To comply with the Third Energy Package, Gas Storage Poland sp. z o.o., a subsidiary of PGNiG's', was established to be an independent storage system operator. There are seven operating storage installations in Poland, ie Wierzchowice Husów, Mogilno, Swarzów, Brzeźnica, Strachocina and Kosakowo. The Polish Energy Policy until 2040 indicates that by 2030 the storage capacity should have increased by one third.

In relation to storage and LNG facilities, the regulated third party access rule is implemented in Polish legislation through the Energy Law Act.

B.4 Tariff regulation

Tariffs for transmission and distribution services must be submitted to the NRA for approval. In relation to sale, currently only retailers selling gas to household consumers must submit tariffs for approval (some other selected entities, such as health care institutions, social care institutions, upon their motion, can also be covered by tariffs). However, under the Energy Law Act this obligation will be repealed as of 31 December 2027.

See also section A.4.

B.5 Market entry

Market entry in Poland, as a rule, requires a licence (see section B.1). No licence or permit from the Energy Authority is required to purchase shares in a licence holder. See also section A.5.

An additional administrative decision is needed to become a system operator.

Under Polish law, energy enterprises engaged in cross-border gas trading and those who import natural gas must keep a statutory gas stockpile equal to or greater than a 30-day average of daily imports. The gas must be stored in facilities whose technical parameters enable the total volume of the statutory stockpile to be withdrawn into the system within a maximum of 40 days. As a rule, all gas subject to the statutory stockpiling requirement must be stored in Poland in storage facilities connected to the system. Under some requirements, stockpiles can also be stored in storage facilities connected to the system located in another EU Member State.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

See section A.6.

Smart metering

The current legislation does not regulate the issue of smart metering in the gas sector.

B.7 Cross-border interconnectors

Poland has the following cross-border gas interconnectors.[14]

- Kamminke (Germany);
- Gubin (Germany);
- Lasów (Germany);
- Mallnow (Germany);
- Branice (Czech Republic);
- Cieszyn (Czech Republic);
- Drozdowicze (Ukraine);
- Wysokoje (Belarus);
- Tietierowka (Belarus);
- Kondratki (Belarus);
- GIPL (Lituania);
- GIPS (Slovakia); and
- Baltic Pipe (Denmark)

The interconnectors are operated by the TSO. Transmission capacities in each of the above connectors can be reserved by way of an auction organised by the TSO.

C. Energy trading

C.1 Electricity

A licence is required in order to conduct an electricity trading and sale business (see section A.5).

Polish energy law provides a general regulatory framework for contracts for the sale of electricity. There are also integrated contracts under which the seller not only sells electricity but also arranges for transmission and distribution services on behalf of the purchaser. Integrated contracts come in two types. Under the first type, the seller contracts the transmission and distribution services in his own name but on behalf of the purchaser (ie it is implicit that the seller is a party to the transmission and distribution contract and pays the related charges to the operator). Under the second type, the seller contracts the services in the name of the customer under a power of attorney (in which case the customer is a party to the contract and pays the operator). The first type is very common in practice.

The essential terms of a contract for the sale of electricity and of an integrated contract are set out in the Energy Law Act. However, the standard form must be developed by the relevant energy undertaking. European Federation of Energy Traders, ie EFET, contracts are sometimes used in Poland, and their use is promoted by Towarzystwo Obrotu Energią, the main association of energy traders. The recent amendment of the Energy Law Act introduced an obligation for the sellers to conclude the integrated contracts and contracts for electricity sale only on the seller's premises, if concluded with household customers. The Polish Energy Policy until 2040 indicates that an obligation to conclude only integrated contracts with household customers will be imposed in the near future.

As a consequence of the implementation of the MIFID II regulations, TGE (Polish Power Exchange) transformed the structure of its business. Currently, within the operations run by TGE, the trade in electricity takes place on the Commodity Market (electricity and gas spot market) and the OTF (electricity and gas forward markets). A.1

Electricity can also be traded in the balancing market. The balance regime is regulated under the transmission grid code. The Polish balancing market is undergoing reform in order to fully implement (i) the solutions envisaged in the EBGL, (ii) recast Electricity Directive, (iii) recast Electricity Regulation and (iv) the obligations that Poland undertook in the process of capacity mechanism notification to European Commission. The reform is planned to be completed by 1 June 2023.

Poland participates in the Single Day-ahead Coupling ("SDAC")." Since 2015 Poland was coupled via the SwePol Link. In 2021, further coupling (on the borders with Germany, Czech Republic and Slovakia) took place. Poland participates also in the Single Intra-Day Coupling ("SIDC"). In 2022, the Core Flow-Based Day-ahead Market Coupling was introduced in Core Capacity Calculation Region (including Poland and 12 other European countries). This harmonization improves the capacity allocation in the Core CCR and enables the European power grid to transport more electricity across borders leading to lower overall cost. Furthermore, it allows for improved cooperation between all involved parties. Finally, market participants are to benefit from further improved transparency of all capacity related data.[15] There are three nominated electricity market operators active in Poland: TGE, EPEX SPOT and Nord Pool.

C.2 Gas trading

A licence is required in order to conduct gas trading activities.

Gas is traded under sales contracts or integrated contracts, the latter having the same structure as in electricity sales (see section C.1).

The legislation on energy does not lay down any contracting procedure for gas. Key terms of the sale and integrated contracts are included in the Energy Law Act. The contracts are usually drafted by the sellers.

Gas is also traded on the Commodity Market and the OTF (see section C.1).

The balancing regime, both physical and financial, is regulated in the transmission grid code.

D. Nuclear energy

The issue of establishing a nuclear power industry in Poland has been up for discussion since 2009, however the need to become permanently independent of energy supplies and energy carriers has given impetus to the investment process in the construction of the first nuclear power plant in Poland. In particular, on 2 November 2022, Council of Ministers adopted a resolution on the construction of large-scale nuclear power plants in the Republic of Poland, submitted by the Minister of Climate and Environment.

The main points of the mentioned-above resolution states that:

- A nuclear power plant with an electrical capacity of up to 3750 MWe will be built based on the American AP1000 reactor technology.
- The construction of the power plant will be carried out in the area of the municipalities of Choczewo or Gniewino and Krokowa in northern Poland. The exact location has not yet been indicated, however, according to the dialogue held between the government and the investor, the preferred location is in the site named "Lubiatowo-Kopalino".
- The first unit shall be built by 2033.
- The investment of large-scale nuclear power plants in Poland will be carried out by Polskie Elektrownie Jądrowe ("PEJ"), which performs tasks aimed at ensuring Poland's energy security.
- The implementation of the nuclear project will be executed in cooperation with the Government of the United States of America. At the end of October 2022, the Polish government announced that Westinghouse Electric Company Energy Systems ("WEC") had been chosen to build the first nuclear plant in Poland. On 15 December 2022, the President of PEJ and the President of WEC signed a cooperation agreement, following the Polish government's selection of the WEC AP1000 technology to build Poland's first nuclear power plant.

The construction of nuclear power plants in Poland is set out in the country's long-term energy strategy, the Energy Policy of Poland until 2040, which was adopted in February 2021. The resolution will enable the implementation of the objective of the government's multi-year programme entitled the Polish Nuclear Power Programme, the update of which was adopted in October 2020. It envisages the construction of 6 to 9 GWe of installed nuclear capacity based on proven, large-scale, pressurised water nuclear reactors consisting of both Generation III and III+, including the commissioning of the first nuclear unit in Poland by 2033.

Two acts constitute the main part of the legal framework for nuclear power plants construction and operation in Poland: (i) the Nuclear Power Investment Act of 29 June 2011 and (ii) the Atomic Law Act of 29 November 2000.

Works on the amendment to the Nuclear Power Investment Act are currently being conducted. According to the project promoters, adopting the amended Nuclear Investment Act would shorten the time needed for the investment by 12-18 months.

E. Upstream

Poland has some rather minor conventional natural gas recourses. Domestic deposits are currently exploited mainly by the PKN Orlen Group; however, there are others with gas exploration licences. Domestic deposits are used for national consumption only. No significant and economically viable shale gas resources have been confirmed in Poland.

Under the Geological and Mining Law Act of 9 June 2011, a licence is required for:

- exploration of or prospecting for minerals;
- extraction of such minerals;
- exploration of or prospecting for underground CO_2 storage complexes;
- exploration of, prospecting for and extraction of hydrocarbons;
- operation of underground storage caverns;
- underground storage of waste; and
- underground storage of CO_2.

These licences fall under the competences of the Minister for the Environment. No licence or permit is required for the takeover of a licence holder or to purchase its shares.

F. Renewable energy

F.1 Renewable energy

The Renewable Energy Directive I requires Poland to ensure that 15% of its final consumption will be provided by renewable energy by 2020. Under Renewable Energy Directive II, Poland has set its national goal at the level of 21%–23% in 2030, depending on the availability of additional EU funds.

The Polish Energy Policy until 2040 reflects the above in the prognosis of the share of energy from renewable sources in the gross final consumption of energy: 15% in 2020, 23% in 2030, and 28.5% in 2040. At the same time, official statistics show that the share of energy from renewable sources in the gross final consumption of energy for 2021 was 15.62% (data for 2021 is published at the end of 2022). Therefore the goal for 2020 was met.

RES in Poland generated a total of approximately 30,568.5 GWh in 2021. More than half (16,233.5 GWh) was produced at onshore wind installations. The generation of electricity from renewable sources has been gradually rising over the period of 2015–2021, however, the rate of growth has seen a decrease due to a 2016 law indicating minimum distances between newly constructed wind turbines and neighbouring buildings. The Polish Government is working on an amendment to this law that would enable a shorter distance and hence increase the potential for onshore wind in Poland.

A support system established to attain the goals and targets provided for in the Renewable Energy Directive I and to promote renewable energy is included in the Renewable Energy Sources Act, which was adopted in 2015 and subsequently amended. However, even before the introduction of this Act, a certificates of origin ("green certificates")" system had been implemented in Poland. Under this old support system, the green certificates were issued by the NRA. These green certificates were transferable and the proprietary rights to them constituted an exchange commodity. To create a market for such rights, assuring the financial means necessary for the development of renewable energy generation, the Energy Law Act required that certain entities had to obtain green certificates and submit them to the NRA for redemption, or pay a substitution fee. The green certificates system has been upheld by the Renewable Energy Sources Act; however, only for existing renewable installations that were granted green certificates under the previous legislation.

For new installations, the Renewable Energy Sources Act implemented an auction scheme where various renewable sources compete for financial support (the lower the price for the energy produced by a particular renewable source, the greater the chances of winning the auction). Separate auctions are held for installations above and under 1MW of installed capacity and additionally for different technologies. The Polish system of support for renewable energy does not currently distinguish between the various renewable energy sources, however, as the government sets maximum prices for each renewable technology that participates in the auction system some of them may turn out to be economically unviable in Poland. Auctions are organised at least once a year. In 2022 auctions were held in December. Of the seven auctions held in December, only three were resolved. Of the total winning bids (204), more than 96% are photovoltaic installations (“PV”) (197), with the other winners being wind installations (5), June and hydroelectric plants (2). Last year's auctions allocated slightly more than 34TWh of electricity from renewable sources with a total value of more than PLN 14.3 billion for sale, but resulted in a total of only around 8.5TWh (25%) of electricity worth less than PLN 2.5 billion (17%) being contracted. The total capacity of new installations that would be built as a result of these auctions is estimated at approximately 500MW3GW in "PV" and 245 MW in wind installations. The above data show a decrease in the general interest in the auction system. The current auction system is planned to be in force until 20278GW.

Existing installations, which continue to be eligible for green certificates, may at their own discretion switch to the auction scheme (provided that such auction is organised).).

There are also separate support schemes for biogas and hydro installations in the form of feed-in tariffs, under which a micro or small producer (whose installation does not exceed 500kW) is entitled to sell unused electricity injected into the grid at a fixed price of 90% of the reference price, and feed-in premiums, under which the producer of electricity in RES installations with a total installed capacity of not less than 500kW and not more than 1MW (a 2.5MW threshold for selected types of installations awaits acceptance by the European Commission) is entitled to sell unused electricity exported into the grid to a selected entity (guaranteed 90% of the reference price).

Under the Renewable Energy Sources Act, there is a special legal framework for the generation of electricity from household-related micro-sources (microgeneration), including eg facilitation of grid connection and other administrative burdens. During 2022, the previous calculation scheme for electricity generated by prosumers, so-called "net-metering" was replaced by a new system – "net-billing". In contrast to the previous net-metering system, where surplus production was counted in kWh, the net-billing system is based on trading surplus electricity production at specific prices. The new system applies to prosumers which connected their installation after 1 April 2022. Prosumers whose installation has been connected prior to this date can still use the previous system.

The development of offshore wind farms are regulated in a separate legal act, the Act on Promoting the Generation of Electricity in Offshore Wind Farms. This act provides for a two-phase support scheme for offshore wind farms. During the first phase, until mid-2021, support is granted through a non-competitive mechanism, on a first-come-first-served basis, by way of administrative decisions issued by the President of the Energy Regulatory Office. During the second phase beginning in 2025, offshore wind farms will participate in auctions modelled on the current auction scheme for RES installations (contract for difference ("CfD")-"like mechanism), but with adjustments to fit the particular needs of offshore wind farms. The European Commission accepted both mechanisms as permitted state aid, however the investors in the first phase will also have to get individual acceptance.

F.2 Renewable pre-qualifications

To take part in renewable energy auctions or obtain support in the form of a feed-in-tariff, generators need to pre-qualify. Each generator needs to present to the Energy Regulatory Office a building permit, the grid connection conditions (ie a promise by the grid operator to connect an installation) or a grid connection agreement, a technical plan of the installation and a financial schedule referring to the construction of the installation. Additionally, the Renewable Energy Sources Act requires that the installations may only consist of new components (ie not older than 24 to 42 months, depending on the installation type). Before taking part in a renewable energy auction, generators are required to pay a deposit or provide the NRA with a bank bond amounting to PLN60,000 for each MW, which, once the auction is won by a specific generator, serves as a security that is held by the market regulator until the sale of electricity is commenced from a particular installation within a certain deadline (for example 24 months from auction closing for PV installations). If the sale of electricity has not begun within this deadline, the deposit is lost. Deposits placed by generators that do not win the auction are returned following the announcement of the auction results.

F.3 Biofuel

The legal, economic and organisational framework for the production and marketing of bio-components and liquid biofuels in Poland is set out mainly in the Biocomponents and Liquid Biofuels Act of 25 August 2006 ("BLB Act")" and the Quality Monitoring and Control System (Fuels) Act of 25 August 2006. This legislation is designed to promote the sustainable and safe development of the production and sale of biofuels.

The BLB Act requires the addition of biocomponents and liquid biofuels to other liquid fuels as it specifies a minimum percentage share of biocomponents in these fuels. As of 1 January 2008, such a share must be ensured by undertakings engaged in the business of production, importation or intra-EU acquisition of liquid fuels or biofuels, if such undertakings sell or otherwise dispose of the fuels in some other form in Poland or use them for their own purposes.

In 2022 as a part of the RePowerEU Plan, European Commission announced an ambitious plan for member states to achieve 35 bcm of biomethane by 2030. Given that there is not a single biomethane plant in Poland, the Polish government has been working on regulations to facilitate the development of the biomethane market in Poland. Drafts of such regulations have not yet been published, however new legal provisions covering this issue are expected to be introduced in 2023.

G. Climate change and sustainability

G.1 Climate change initiatives

Climate policy in Poland is strictly related to the EU legislative framework. The main focus of Government policy is related to the following areas: renewable energy generation support (Renewable Energy Sources Act, Act on Promoting the Generation of Electricity in Offshore Wind Farms) and electromobility (Electromobility and Alternative Fuels Act).

The renewable energy generation support system is based on a self-financing mechanism (by end users of energy) and is created as a CfD-like scheme. The Government also supports the development of micro PV installations (2kW to 10kW) by providing grant subsidies for households.

Support is also available in the area of electromobility. The Electromobility and Alternative Fuels Act indicates minimum thresholds of use by governmental agencies and local government entities of EVs and/or vehicles using LNG. In July 2021 the Government introduced grant support for the purchase of EVs (up to PLN27,000 per vehicle, which amounts to about 440% of the average monthly gross wage and salary in Q2 2022).

The Government has also introduced a Clean Air Fund which subsidises the modernisation of household heating systems (up to PLN66,000 depending on the scope of the investment, which amounts to about 1000% of average monthly gross wage and salary in Q2 2022).

G.2 Emission trading

Legal provisions implementing the EU Emissions Trading System ("EU ETS")" are contained in the Act of 17 July 2009 on the System to Manage the Emissions of Greenhouse Gases and Other Substances ("Emissions and GHG Act")," which was further supplemented by the Act of 12 June 2015 on the GHGs

ETS, implementing EU legislation, ie the GHGs and ETS Act. These acts determine the rules by which the ETS operates. The ETS in Poland consists of the EU ETS and the national trading system. Polish law was adapted between 2011 and 2015 to fully comply with the EU ETS Directive.

G.3 Carbon pricing

There is currently no strategy for carbon pricing in Poland.

G.4 Capacity markets

On 8 December 2017, a law on a capacity market was adopted, based on rules similar to those governing the capacity market in the UK. Under the Capacity Market Act, electricity generators are paid for holding their generating units on standby, ready to provide capacity whenever needed. The law also includes means designed to actively engage the demand side in the capacity market. The support is granted in auctions. The first auctions were held in 2018, for delivery periods in 2021, 2022 and 2023. Between 2019 and 2025, one main auction is organised each year for delivery periods falling within the years 2024 to 2030. The capacity market scheme was accepted by the European Commission as permitted state aid.

H. Energy transition

H.1 Overview

The Polish energy transition is a process that is reflected in the Polish Energy Policy until 2040. As indicated in the Policy, just transition, a zero-emission energy system, and good air quality are the three pillars of the energy transition. The first of these, just transition, includes the transition of coal regions, decreasing levels of energy poverty, and the creation of new industrial sectors based on the development of renewable and nuclear energy. The zero emission energy system is based on offshore wind power plants, nuclear energy and local and prosumer (where energy consumers also produce energy) energy generation. The third pillar, that of good air quality, is based on heating systems' transformation, e-mobility, and the use of local sources for the energy needs of buildings. Some of these steps, eg e-mobility and the use of local sources for the energy needs of buildings, are reflected in the state aid programmes. See section G.1.

The Polish Energy Policy until 2040 notes its objective is to guarantee energy security "while ensuring the competitiveness of the economy, energy efficiency and reduction of the environmental impact of the energy sector, and with optimum use of Poland's' own energy resources". The main transition elements are: (a) a reduction in the share of coal in electricity generation (coal is planned to cover 56% of generation of electricity in 2030), an increase in renewable energy (23% in gross energy consumption in 2030), a reduction in CO_2 emissions by 30% in 2030 (in relation to 1990), an improvement in energy efficiency by 23% in 2030 (in relation to the forecasts from 2007) and the introduction of nuclear energy in 2033.

H.2 Renewable fuels

Legislation on the use of renewable fuels focuses mainly on electricity, however, on 7 December 2021, the "Polish Hydrogen Strategy until 2030 with an outlook to 2040" was published in the Official Journal of the Republic of Poland "Monitor Polski".[16] This is part of global, European and national activities aimed at building a low-carbon economy. The strategy indicates six main goals:

- implementation of hydrogen technologies in the energy sector;
- use of hydrogen as an alternative fuel in transport;
- support for industry decarbonisation;
- hydrogen production in new installations;
- efficient and safe distribution of hydrogen; and
- creating a stable regulatory environment.

In addition to the above, the amendment to the Electromobility and Alternative Fuels Act dated 24 December 2021 provides for solutions for the use of hydrogen as an alternative fuel in transport, including development plans for a hydrogen refuelling infrastructure.

The "Polish Hydrogen Strategy until 2030 with an outlook to 2040" refers to the use of ammonia in addition to hydrogen. It includes ammonia-based technologies as potentially contributing to the achievement of environmental goals in transport.

The "Polish Hydrogen Strategy until 2030 with an outlook to 2040" indicates the role of ammonia in the country's' energy transformation. The Policy specifies that ammonia will play a role in the implementation of hydrogen in transport through the use of synthetic fuels such as fuels using ammonia synthesis based on green hydrogen.

In the third quarter of 2022, the Polish government published a draft act amending the Energy Law and certain other acts which enables the implementation of the above-mentioned objective no. 6 "*Creating a stable regulatory environment*". The amendment is part of a legislative package called the Constitution for Hydrogen, which main goal is to create a regulatory framework for the functioning of the hydrogen market. The cross-cutting changes contained in it assume, among other things, the introduction of regulations necessary for the development and operation of the hydrogen market in Poland.

H.3 Carbon capture and storage

In 2013, Poland transposed the CCS Directive (the deadline was 25 June 2011).

Under the legislation, carbon storage and exploration of geological formations in which carbon dioxide can be stored would require a concession from the Minister of the Environment.

Poland has not prepared a national roadmap for CCS deployment. The current Polish Energy Policy until 2040 indicates that international studies show that low or no emission use of coal is possible, which could enable the further use of existing coal fired generation units. In that context, the policy indicates new methods of using coal will be studied, developed and implemented, which also includes CSS. Some experimental CO_2 capture and sequestration projects have also been implemented in Poland. Other fully fledged sequestration projects are being developed as EU demonstration projects.

H.4 Oil and gas platform electrification

The electrification of Polish industry sectors is contemplated in the Polish Energy Policy until 2040 as one of the actions aimed at energy transition. However, no direct reference was made to oil and gas businesses.

H.5 Industrial hubs

There are 14 special economic zones in Poland which were created based on the Special Economic Zones Act. Their goal is to promote certain regions in Poland by attracting investors based on tax incentives. From 2017, based on the Act on Support for New Investments, tax incentives that had previously been available only in special economic zones are now available in the entire territory of Poland; the still existing rules regarding special economic zones will continue to apply until 2026. The supports vary depending on the location of the investment, local factors (eg unemployment rate) and the type of investment.

H.6 Smart cities

Most of the cities and towns in Poland implement various programmes aimed at becoming a 'smart city'.'' Such programmes are focused on implementing innovative technology for the benefit of the local communities. Many cities and towns in Poland also join worldwide, European or local smart-cities initiatives. Although there is no specific legislative framework regarding smart cities in Poland, its elements can be found in certain legal acts, e.g., the Electromobility and Alternative Fuels Act introduces certain requirements for the modernisation of local public transport fleets through the introduction of emissions-free buses.

I. Environmental, social and governance (ESG)

The worldwide trends relating to ESG goals are also reflected in the Polish market, including in the energy sector. Some of the investments in the Polish energy market are fuelled by ESG-linked loans or bonds. All of the main Polish energy groups are involved in renewable investments in Poland, which include goals of reaching emission neutrality.

Endnotes

1. See www.ure.gov.pl/download/9/13117/RaportRocznyPrezesaURE2022.pdf.
2. See www.ure.gov.pl/download/9/12909/SPRAWOZDANIEPURE2021.pdf.
3. See www.ure.gov.pl/download/9/12909/SPRAWOZDANIEPURE2021.pdf.
4. See www.ure.gov.pl/pl/biznes/jak-uzyskac-koncesje/energia-elektryczna.
5. See article 4(2) of Energy Law Act of 10 April 1997 (as amended).
6. See www.ure.gov.pl/pl/urzad/informacje-ogolne/aktualnosci/10787,Rynek-energii-elektrycznej-w-listopadzie-2022-r-prawie-15-tys-odbiorcow-w-gospod.html.
7. See www.api-raport.pse.pl/PSE-Zintegrowany_Raport_Wplywu_2022.pdf.
8. See www.ure.gov.pl/download/9/12909/SPRAWOZDANIEPURE2021.pdf.
9. Within the meaning of the Act of 26 October 2000 on commodity exchanges
10. See www.ure.gov.pl/download/9/12909/SPRAWOZDANIEPURE2021.pdf
11. See www.ure.gov.pl/download/9/11992/Sprawozdanie2020.pdf.
12. See www.ure.gov.pl/download/9/11992/Sprawozdanie2020.pdf.
13. See article 4(2) of Energy Law Act of 10 April 1997 (as amended).
14. See www.gaz-system.pl/dam/jcr:8dfb8bfc-c33d-4107-95a4-16efc89f0ab9/krajowy-plan-rozwoju-gaz-system-2022-2031.pdf.
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Energy law in Portugal

Recent developments in the energy sector in Portugal

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Roadmap for carbon neutrality

After the Portuguese Government ("Government") announced at COP 22 the national goal to achieve Carbon Neutrality by 2050, the Resolution of the Council of Ministers no. 107/2019, of 1 July, approved the Roadmap for Carbon Neutrality 2050. The purpose of the Roadmap for Carbon Neutrality 2050 is to assess the viability of trajectories leading towards carbon neutrality, to identify the main decarbonisation vectors, and to estimate the potential for reduction in each activity sector (the roadmap was drafted following a public consultation procedure with Portugal's main activity sectors).

To achieve carbon neutrality, the Government has set a goal to reduce greenhouse gas ("GHG") emissions between 85% and 95% until 2050 when compared to 2005 levels; and through a trajectory of reduction between 45% and 55% by 2030 and 65% and 75% by 2040 to 2005 levels.

The Decree-Law 84/2022 materializes this vision, updating the national targets for renewable energy in final energy consumption, also extending the system of issuing guarantees of origin to energy production through high-efficiency cogeneration. It also establishes more ambitious targets for the contribution of renewable energy in the transport sector and defines new targets for maritime, air and rail transport; deepens the already existing biofuels regime and foresees the creation of a verification regime for compliance with sustainability and greenhouse gas emission reduction criteria and encourages the use of road transport fuels with a higher percentage of biofuel incorporation, as long as the safety of its use is safeguarded. Finally, it concludes the transposition of Directive (EU) 2018/2001, materializing the national commitment to the European strategy of decarbonization and energy transition, for a more sustainable future.

The main strategies for decarbonisation are:

- decarbonising the generation of electricity, investing in endogenous renewable resources;
- materialising the energy transition, enhancing energy efficiency in all market sectors;
- decentralising the generation of electricity by including the consumer in the generation activity;
- promoting decarbonisation in the residential sector by promoting building renovations;
- decarbonising mobility, promoting public transport and decarbonisation of the fleets;
- promoting decarbonisation in the industry;
- investing in sustainable agriculture by incorporating low carbon production processes;
- fomenting carbon capture through forest and agricultural management promoting the valuation of the territory;
- transitioning from a regular consumption model to a circular consumption model; (ix) encouraging innovation and development ("I&D") aimed at achieving neutrality in the various sectors; and
- using taxation as an instrument to achieve carbon neutrality.

National Plan for Energy and Climate 2030

Following the approval of the Roadmap for Carbon Neutrality, the Resolution of the Council of Ministers no. 53/2020, of 10 July, approved the National Plan for Energy and Climate 2030 (*Plano Nacional Energia e Clima 2030* ("PNEC 2030")).

The PNEC 2030 reinforced the importance of complying with the trajectory targets for 2030:

- reducing GHG emission between 45% to 55% for reference of emissions registered in 2005;
- incorporating 47% of renewable energy sources (RES) in the final gross consumption of energy;
- reducing the consumption of primary energy by 35% to improve energy efficiency; and
- achieving 15% of electricity interconnections with its neighbouring country, Spain, to strengthen the security of Portugal's energy supply.

Regarding Portugal's sectors, the targets for the reduction of GHG emissions are:

- 70% within the service sector;
- 35% within the residential sector;
- 40% within the transport sector;
- 11% within the agricultural sector; and
- 30% within the waste and water waste sector.

Hydrogen strategy

The Resolution of the Council of Ministers no. 63/2020, of 14 August set forth the Hydrogen Strategy ("EN-H2"). The implementation of the EN-H2 will involve reshaping the regulatory framework and will require the mobilisation of substantial investments (public and private), thus opening the door to re-design the Portuguese energy sector.

The hydrogen targets for 2020-2030 are:

- 5% of final energy consumption;
- 5% of road transport consumption;

- 5% of industry consumption;
- 10% to 15% of injection on the natural gas transmission networks;
- between 50 and 100 supply stations; and
- 2 to 2.5GW of electrolysers' capacity.

Three implementation phases are established by the implementation of the National Hydrogen System.

Phase I: 2020-2023

- adopt the regulatory framework (for all hydrogen value chains);
- study and implement investment supporting mechanisms;
- implement small to medium scale projects in several economic sectors;
- implement professional educational programmes;
- design I&D incentives; and
- begin implementing the Sines industrial project.

Phase II: 2024-2030

- implement varied scale projects nationwide;
- implement and complete the Sines industrial project;
- strengthen and revise the regulatory framework;
- strengthen supporting mechanisms with EU funds;
- strengthen the industrialisation capacity within the various components of the value chain; and
- revise the EN-H2.

Phase III: 2030-2050

- consolidate hydrogen as a decarbonisation instrument, generating revenue and employment in Portugal; and
- revise the EN-H2

The implementation of the EN-H2 is expected to bring interesting news and opportunities for new players, the reconfiguration of existing projects, and the performance of installed players. In view of implementing the required changes, the process of adapting the regulatory framework is already underway, in particular:

- Decree-law no. 62/2020, of 28 August, has adapted the organisation and operation rules of the National Gas System and the respective legal regime with a view to promote the development and regulation of renewable sources gas production activities and production of low-carbon gases, as well as the incorporation of these gases in the National Gas System; and
- Decree-law no. 60/2020, of 17 August, has outlined the mechanism for the issuance of guarantees of origin for low carbon gases and for gases of renewable origin.

Overview of the legal and regulatory framework in Portugal

A. Electricity

A.1 Industry structure

Nature of the market

The National Electricity System's (*Sistema Elétrico Nacional*) ("SEN's") value chain includes the following activities:

- Generation (unregulated activity): open to competition, subject only to licensing;
- Transport and transmission (regulated activities): the Transmission System Operator ("TSO"),[1] operates on an exclusive basis under a 50-year public service concession agreement[2] with the Portuguese State ("State"), under which it is responsible for: (i) planning, implementing and operating the National Transmission Grid ("RNT") and related infrastructures; (ii) all relevant interconnections and other facilities necessary to operate the RNT; and (iii) coordinating the SEN infrastructures to ensure the integrated and efficient operation of the system, as well as the continuity and security of electricity supply (as Global Technical System Manager);
- Distribution (regulated activity): the Distribution System Operator ("DSO") operated on an exclusive basis under a 35-year public service concession agreement[3] with the State for the distribution of electricity at high and medium voltages and under 20-year municipal concession agreements with the relevant municipalities for distribution of low-voltage;
- Trading and supply (regulated and unregulated activities): except for the activity of last resort supplier and market facilitator, supply of electricity is currently a free access business, subject only to prior registration and certain public service obligations ("PSOs") regarding the quality and continuity of supply, as well as consumer protection rules as per the prices, access charges and access to information in simple and understandable terms;
- Operation of the electricity markets (regulated activity): this is a free access activity, the operation of organised markets for electricity is subject to joint authorisation from the Minister of Finance and the Minister responsible for the energy sector and the entity managing the organised markets is also subject to authorisation from the Minister responsible for the energy sector and, when required by law, from the Minister of Finance[4]; and
- Logistics Operator for Switching Electricity and Gas Supplier ("OLMC") (regulated activity): responsible for overseeing the process of switching electricity and natural gas suppliers. For further details see section C.

Key market players

- TSO, i.e REN (*Redes Eléctricas Nacionais S.A.*).
- DSO, i.e E-REDES (previously *EDP Distribuição*).
- In the Autonomous Regions (Azores and Madeira), the DSOs are Electricidade dos Açores and Empresa de Electricidade da Madeira, respectively.[5]
- The supplier of last resort is EDP Serviço Universal, S.A..
- OLMC is the Portuguese Energy Agency – ADENE.

Regulatory authorities

The Portuguese Energy Services Regulatory Authority (*Entidade Reguladora dos Serviços Energéticos* ("ERSE")) is the independent national regulatory authority for the electricity and natural gas sectors, holding regulatory, supervisory, and disciplinary powers. ERSE carries out its duties independently within the guidelines of the energy policy established by the Government and can impose fines on energy companies for non-compliance with the applicable legal framework.

The Portuguese Competition Authority ("AdC")[6] is the independent and financially autonomous institution that ensures compliance with competition rules in Portugal, holding regulatory, supervisory and disciplinary powers.

The Directorate General of Energy and Resources ("DGEG")[7] is the Portuguese Public Administration body whose mission is to contribute to the design, promotion and evaluation of policies regarding energy and geological resources, with a view to sustainable development and guaranteeing security of supply. The DGEG acts as the national authority for energy and geological resources, licensing and international relations, and since 2018, the research, finding and extraction of hydrocarbons; therefore, representing the State in all matters thereof.

Legal framework

The basic legal framework for the electricity sector consists of:

- Decree-Law no. 15/2022, of 14 January;
- Statutes of ERSE;[8]
- Energy Sector Sanctioning Regime;[9]
- ERSE regulations;[10] and
- regulations put into force by DGEG.

Implementation of EU electricity directives

The framework for the organisation of the SEN was approved in 1995 and established a coexistence of the public service electricity system and the independent electricity system, the latter being market-based.

In 1997, the framework was amended to enshrine the principles set forth by the First Electricity Directive. Notwithstanding the aforementioned basic legal framework currently in force, the framework was originally drafted for the implementation of the Second Electricity Directive.

Throughout 2011 and 2012, the Third Electricity Directive was implemented:

- through the amendment to Decree-Law no. 29/2006, of 15 February, which sets forth the National Electricity System (*Sistema Elétrico Nacional*); and
- through the amendment and complete republication of Decree-Law no. 172/2006, of 23 August, by Decree-Law no. 215-B/2012, of 8 October which governs the generation, transmission, distribution and commercialisation of electricity.

Both pieces of legislation – Decree-Law no. 29/2006, of 15 February, and Decree-Law no. 172/2006, of 23 August, amended by Decree-Law no. 215-B/2012, of 8 October – were recently revoked by Decree-Law no. 15/2022, of 14 January, which sets the organisation and functioning of the SEN and implemented the Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU and (partially) the revised Renewable Energy Directive (Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources).

Recently, Decree-Law no. 84/2022, of 9 December, establishes targets for the consumption of energy from renewable sources, partially transposing Directive (EU) 2018/2001, and includes references to green certificates (garantias de origem) which regime was presented in Decree-Law no. 15/2022, of 14 January.

A.2 Third party access regime

To ensure equal access and use to all market players, the TSO and DSOs are subject to PSOs.

The integration of electrical installations is performed under a specific network connection:

- The Distribution Grid Regulation (*Regulamento da Rede de Distribuição*), adopted by Order in Council no. 596/2010, of 30 July, which governs the technical operating conditions of the high, medium and low-pressure tension networks comprised in the Public Grid, as well as the relationships between the network operators and the entities with facilities connected to them;
- The Transport Grid Regulation (*Regulamento da Rede de Transporte*), also adopted by Order in Council no. 596/2010, which governs the technical operating conditions of the interconnection of the National Transport Network infrastructures, as well as the technical conditions related with the planning and exploitation of the National Transport Network;
- The Commercial Relation Regulation (*Regulamento das Relações Comerciais*),[11] which sets out the provisions regarding the commercial relations between the various parties involved in the SEN, the commercial conditions for the connection to public networks, the operation of commercial relations in the electricity systems of the Autonomous Regions, and the functioning of trade between those electrical systems and the electrical system of continental Portugal; and
- The Access to Networks and Interconnections (*Regulamento de Acesso às Redes e às Interligações, RARI*),[12] which sets out provisions related to technical and commercial conditions according to which the access to the networks and the interconnections is processed, as well as the conditions under which access is granted or restricted, and also the reimbursement to which entities are entitled for offering access to their networks.

A.3 Market design

Subject to certain exceptions, each of the activities referred to in section A.1 shall be carried out independently from a legal, organisational, and decision-making standpoint (unbundling), as a consequence of European Union ("EU") legislation being transposed into Portuguese national law.

Electricity sector activities must be developed in accordance with the principles of rationality and efficiency in the use of resources throughout the entire value chain (ie from generators to the final consumption of electricity) and in accordance with the principles of competition and environmental sustainability, with the purpose of increasing competition and efficiency in the SEN, without prejudicing PSOs.

A.4 Tariff regulation

ERSE is responsible for preparing and approving the Tariff Regulation (*Regulamento Tarifário do sector eléctrico*)[13] that sets the methodology to be used for calculating tariffs, as well as the ways to regulate the allowed revenues. The various stakeholders in the SEN (consumers and electricity industry) are involved in its process of approval, as it is preceded by a public consultation and an opinion from ERSE's Tariff Board, thereby ensuring regulatory stability and transparency on the basis of a non-discrimination principle applicable to tariffs and billing.

Consumers acquire the electricity from the relevant electricity trading entities operating in Portugal, which in turn, acquire the electricity from the Portuguese transport or distribution operator of electricity, as applicable, that acquire the same from the relevant generators.

The tariff system is additive as each regulated activity has an associated regulated tariff,[14] with the final sales tariff applicable to each end user being composed by the sum of the various activity tariffs which are attributable to this client's supply.

In the free market, energy sale prices are set by agreements between suppliers and customers, part of the price being passed through to the regulated tariffs mentioned above. On the contrary, under the regulated market, the tariffs and prices practiced by the last resort supplier in the sale tariff to end users are defined by ERSE. ERSE also sets the social tariff to be applied by the last resort supplier to economically vulnerable end-users (810,000 by the end of 2020).

By September 2018, 5,070,014 end users had chosen to move to the liberalised market. Those that have not yet done so benefit from a regulated supply tariff, as established by ERSE. The abolition of such tariffs, ie deadline to shift to the liberalised market, was due on 31 December 2020. Nonetheless, the State Budget for 2020[15] and Order no. 83/2020, of 1 April, extended the deadline applicable to the supply of electricity in regular and special low voltage (*Baixa Tensão Normal e Especial*) to the end of 2025 and the end of 2022, respectively, and to the end of 2021 for the supply in medium voltage (*Média Tensão*).

A.5 Market entry

See section A.1.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Decree-Law no. 15/2022, of 14 January, as amended, establishes a number of mandatory PSOs, including:

- security, regularity and quality of supply;
- guaranteed universal service provision;
- ensuring the connection of all customers to the networks;
- protection of consumers, particularly with regard to tariffs and prices;
- promotion of energy efficiency, environmental protection and rational use of renewable and indigenous resources; and
- convergence of the SEN, translated into solidarity and cooperation with the electrical systems of the Autonomous Regions.

Smart metering

Smart metering was introduced in Portugal following the Third Electricity Directive and the Third Gas Directive. The technical and functional requirements of smart meters, as well as the rules applicable to the provision of information and billing and financing of the costs inherent in the respective installation have been set out by Order in Council no. 231/2013, of 22 July.

Electric vehicles

Regarding electric vehicles ("EVs"), Order in Council no. 20/2009, of 20 February[16] created the Programme for Electric Mobility in Portugal (*Programa para a Mobilidade Elétrica em Portugal*) with the purpose of introducing and massifying the use of EVs.

Following the above Order, Decree-Law no. 39/2010 established the legal framework for electric mobility (*Regime Jurídico da Mobilidade Elétrica*). The reasoning for the drafting of this pioneer legal framework was to:

- ensure environmental sustainability;
- optimise the use of electrical power; and
- optimise the advantages of the energy generated from RES.

Several measures have been adopted in order to achieve electric mobility aiming at:

- incentivising the purchase of EVs;
- creating a national network of charging points;
- demanding the existence of charging points in new buildings; and
- installing charging points in existing buildings.

A.7 Cross-border interconnectors

Portugal's peripheral location is a challenge; however, the country is fully connected to the Spanish TSO (managed by REE – *Red Eléctrica de España, S.A.U.*). In 2018, the interconnection of very high voltage electric systems of Portugal and Spain consisted of nine lines operating on alternating current, of which six are in the 400kV voltage level (one double) and three are operating at 220kV.[17] Even though a new interconnection (400kV line) between Portugal (Minho) and Spain (Galicia) is on the List of Projects of Common Interest ("PCIs") and the commissioning of this PCI was planned for 2021, so far the project has faced resistance from local populations and has not got off the ground. On completion, it would enable an interconnection above the 10% target between both countries.

The Lisbon Declaration (27 July 2018) of the Second Energy Interconnections Summit (France, Spain and Portugal, European Commission and EIB) highlights the urgency of implementing the already planned electricity interconnections in order to strengthen regional cooperation within the framework of the Energy Union and better integrate the Iberian Peninsula into the internal energy market.

B. Oil and gas

B.1 Industry structure

Nature of the market

The Portuguese Natural Gas System is divided in the following activities:

- Acquisition and Import (unregulated): Portugal has no natural gas resources of its own, instead the supply is ensured through entrances in the system via the interconnection points with Spain (Campo Maior and Valencia) as well as the terminal in the port of Sines, through long-term take-or-pay contracts (the main natural gas suppliers being Algeria and Nigeria);
- Reception, Storage and Re-gasification of Liquefied Natural Gas ("LNG") (regulated): such activities are performed through a public service concession granted by the State;
- Underground storage of natural gas (regulated activity): performed through public service concessions granted by the State covering underground storage, construction, operation, maintenance and expansion facilities and infrastructure; and the extraction, treatment and delivery of natural gas;
- Transmission and technical global management of the system (regulated): performed through a public service concession granted by the State to the TSO for a 40-year period. This concession includes: (i) the transport of natural gas through a high-pressure network for receiving and delivering the product to distributors, traders or major clients; and (ii) the transport of LNG through tank trucks to autonomous units and the respective delivery to distributors or major clients;
- Distribution of natural gas (regulated): this activity includes (i) the distribution of natural gas in the gaseous state, through medium and low networks for the purposes of receiving and delivering the product to final customers; and (ii) the reception, storage, and regasification of LNG in autonomous units and its delivery to final customers through the distribution networks. Regarding regional distribution networks,[18] the activity is performed through the operation of the national network of distribution of natural gas and within

public service concessions granted by the State on an exclusive basis. Autonomous local networks, run on distribution licences,[19] also in an exclusive basis and under the public service regime;

- Commercialisation and supply (regulated and unregulated): gas suppliers must manage the relations with the end users. These activities can be performed through free or regulated markets, that are subject to the granting of the respective licence and the payment of a regulated price, which grants access to the storage facilities and units of LNG and to the transmission and distribution networks;
- Operation of natural gas markets: this activity is free and subject to joint authorisation from the Minister of Finance and the Minister responsible for the energy sector. The entity managing the organised markets is also subject to authorisation from the Minister responsible for the energy sector and, when required by law, from the Minister of Finance; and
- OLMC (regulated activity): since 2017, the Portuguese Energy Agency, ADENE, has been responsible for overseeing the process of switching electricity and natural gas suppliers. For further details please refer below, to Section C.

The oil system is organised under the following activities:

- prospecting, exploration, development and production, exercisable through concession;
- preliminary evaluation studies are secured by licence;
- administrative procedures relating to the exploration and exploitation of hydrocarbons is subject to compulsory consultation to the municipalities; and
- all consultations are promoted by DGEG.

Key market players

- The main gas importer is Galp Gás Natural, S.A.;
- REN-Atlântico, Terminal de GNL, S.A., the LNG concessionaire for a 40-year period; and
- REN, Armazenagem, S.A. and Transgás Armazenagem, S.A., underground natural gas storage concessionaires.

Regulatory authorities

Without prejudice to the competences assigned to other administrative bodies, such as DGEG or AdC, the regulation and supervisory activities are performed by ERSE (see section A.1).

Legal framework

The structure and organisation of the oil and natural gas sector results from:

- Decree-Law no. 109/94 of 26 April, as amended by Decree-Law no. 82/2017, of 18 August, and Decree-Law no. 31/2006, of 15 February, as amended by Law no. 69-A/2021, of 21 October, setting forth the Legal Framework for the Oil Prospecting, Research, Development and Production Activities;
- Decree-Law no. 30/2006, of 15 February,[20] general principles governing the organisation and functioning of the National Natural Gas System ("SNGN") the performance of activities of reception, storage, transport, distribution, and sale of natural gas; and
- Decree-Law no. 140/2006, of 26 July,[21] setting out the regime of natural gas activities, concession bases and licences.

Implementation of EU gas directives

Decree-Law no. 30/2016, of 15 February, and Decree-Law no. 140/2006, of 26 July transposed the Third Gas Directive. Both diplomas have been revoked by Decree-Law no. 62/2020, of 28 August, as amended by Decree-Law no. 70/2022, of 14 October, which approved the Natural Gas National System and respective licensing basis, and transposed Directive 2019/692 that amended Directive 2009/73/EC concerning common rules for the internal market in natural gas.

B.2 Third party access regime to gas transportation networks

To ensure equal access and use to all market players, the TSO and DSOs are subject to PSOs.

The Order no. 142/2011, of 6 April, as amended by Order no. 235/2012, of 8 August, approved the Natural Gas Transport National Network Regulation (*Regulamento da Rede Nacional de Transporte de Gás Natural*), which establishes the technical and safety conditions that must be complied with in the design, construction, operation, maintenance and putting out of service of the infrastructures of the National Natural Gas Transport Network. The former requisites assist in ensuring the adequate flow of natural gas, interoperability with the networks to which they are connected, and the safety of persons and property.

The Access to Networks and Interconnections Regulation (*Regulamento de Acesso às Redes e às Interligações do sector do gás natural, RARII*)[22] sets out transparent and non-discriminatory criteria to establish the technical and commercial conditions to access natural gas networks, natural gas underground storage facilities, LNG terminals and interconnections. In particular, involving technical and commercial aspects related to third party access to the infrastructures mentioned above.

Access to the Public Grid infrastructures is formalised by means of a written agreement of the following infrastructure use contracts:

- LNG Receiving, Storage and Regasification Terminal Use Agreement;
- Underground Natural Gas Storage Use Agreement;
- Transportation Network Use Agreement; and
- Distribution Networks Use Agreement.

B.3 LNG terminals and storage facilities

Natural gas is received at the border and transported by high-pressure Natural Gas Transport Network pipelines connected through pressure metering and reduction stations, to the medium-pressure pipelines operated by distribution companies.

At the underground storage facility located at Carriço (Pombal), the high-pressure natural gas is stored in gaseous form, in caverns created inside salt formations at depths of over 1,000 metres. This activity is related to the constitution and maintenance of natural gas security provisions that are crucial to ensure the supply and creation of an operational provision to allow the stock management of natural gas to safeguard constant availability of the product in case of additional demand.

The reception, storage and re-gasification of LNG is performed in the only existing facility, located in Sines (on the Atlantic coast, about 120km south of Lisbon), which started operations in 2004 and become the first in Europe to receive LNG from the United States in 2016.

Within the isolated distribution networks supplied by Autonomous Gas Units (UAG) (developed in the areas where the construction of the high-pressure network was not economically viable) the supply is performed by tank trucks as from the LNG terminal.

B.4 Tariff regulation

For each regulated activity (see section B.1), ERSE annually determines the profit allowed in accordance with the methodologies of regulation defined in the Tariff Regulation (*Regulamento Tarifário do Sector do Gás Natural*).[23] The prices are calculated according to the gains which are allowed and established on an annual basis for the relevant players as established in Chapter IV of the Tariff Regulation.

All prices comprise:

- the fixed prices defined for each tariff, in euros per month;
- the prices of the utilised capacity in euros per KWh/day, per month; and
- the energy prices which differ according to the relevant period (peak or off peak), in euros per KWh. Prices can also differ according to the level of pressure, tariff period or annual consumption grade.

B.5 Market entry

See section B.1.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Decree-Law no. 62/2020, of 28 August, as amended by Decree-Law no. 70/2022, of 14 October, sets forth the following mandatory PSOs:

- security, regularity and quality of supply;
- the incorporation of gases of renewable origin and of gases with low carbon content.
- the guarantee of connection of customers to the networks under the terms foreseen in the concession contracts or in the licence titles;
- contributing to the progressive decarbonisation of the National Gas System, with the aim of achieving carbon neutrality by 2050;
- protection of consumers with regards to tariffs and pricing; and
- promotion of energy efficiency, environmental protection, and rational use of renewable and indigenous resources.

Smart metering

Smart metering is not currently implemented in the oil and gas market.

B.7 Cross-border interconnectors

There is no natural gas production in Portugal. There are three points of entrance for gas, ie one regasification plant (Sines) and two interconnections with Spain (via Campo Maior and Valença do Minho).[24]

The third interconnection between Portugal and Spain, listed as a PCI, will be developed in three phases in Portugal and two phases in Spain and will connect Celorico da Beira to Zamora (pipeline Celorico/Vale de Frades) with a total length of between 242 and 247km (162km in Portugal and 80 or 85km in Spain). The commissioning of the project is expected by 2024.

C. Energy trading

Decree-Law no. 15/2022 of 14 January, set up the Logistics Operator for Switching Electricity and Gas Supplier and Aggregator (previously OLMCA, now ADENE), which reports to the Government and is subject to ERSE's regulatory powers. ADENE was created to facilitate the change of supplier by the end user, based on simple rules and transparent, standardised, and dematerialised procedures, and to ensure the right of consumers to information.

C.1 Electricity trading

As of September 2006, all consumers are entitled to choose their electricity supplier, by execution of one of the following contracts:

- contract for the supply of electricity with suppliers in the liberalised market;
- in the case of customers with market agent status, contracting the acquisition of electricity in organised markets or through bilateral contracts; or
- electricity supply contract with last resort suppliers, only in the legal and regulatory conditions set out.

Electricity is currently traded between generators and suppliers in the Iberian Electricity Market ("MIBEL"), which is a joint initiative of the Governments of Portugal and Spain, based on a spot (day ahead and intraday) market (operated by the OMIE) which sustains the Mechanism for Joint Management of the Portugal-Spain Interconnection (since 1 July 2007) and a forward and derivative market (operated by the OMIP) (since July 2006).

MIBEL operates on the basis of the following legal and regulatory instruments:

- New Electricity Regulation;
- Access to Networks and Interconnections;
- Procedures Manual for the Mechanism for Joint Management of the Portugal-Spain Interconnection;
- Joint Rules for Contracting Capacity in the Portugal-Spain Interconnection; and
- Rules and principles for the harmonised allocation of financial rights for the use of interconnection capacity.

C.2 Gas trading

As of January 2010, all natural gas consumers are entitled to choose their natural gas supplier by execution of one of the following contracts:

- contract for the supply of natural gas with suppliers in the liberalised market;
- natural gas supply contract with suppliers of last resort; or

- in the case of customers with market agent status, natural gas procurement in organised markets or through bilateral contracts.

The Iberian Natural Gas Market ("MIBGAS") is a gradual process, which has been ongoing since 2007 and had the first trading session in December 2015. It is dependent on the harmonisation and integration of the systems of the natural gas sector in Spain and Portugal and is aimed at contributing to the achievement of a European market for natural gas. The third Portugal-Spain interconnection plays an especially important role in the construction and consolidation of MIBGAS.

MIBGAS aims to:

- increase security of supply through market integration and coordination of both systems of the natural gas sector and strengthening of interconnections;
- increased competition, reflecting the larger size of the market and a higher number of participants;
- simplified and harmonised regulatory framework in both countries; and
- more efficiency of regulated and liberalised activities as well as market transparency.

D. Nuclear energy

No nuclear energy is currently generated in Portugal.

E. Upstream

There are currently no upstream activities in Portugal.

F. Renewable energy

F.1 Renewable energy

Decree-Law no. 215-B/2012, of 8 October, transposed the Third Electricity Directive and operated the revision and consolidation of the legal framework applicable to the generation of electricity under the so-called, at the time, “Special Regime”.

Generation under the Special Regime encompasses two different remuneration regimes, the common regime and the guaranteed remuneration regime.

Decree-Law 15/2022, of 14 January, adopted the market price as the general remuneration regime. In any case, this new legal regime allows projects prior to 2022 to maintain the guaranteed remuneration scheme if that was established previously.

In order to understand the guaranteed remuneration scheme, the wind tariff system has been amended with no retroactive effects (Decree-Law no. 35/2013, of 28 February), by mutual agreement with the Portuguese Renewable Energy Association (*Associação de Energias Renovávei*) (APREN). These rules established that, against the payment of a fee, wind farms would benefit from a guaranteed tariff for an additional period of five years after the end of the initial 15-year period provided for such FiT. Additionally, Decree-Law no. 35/2013, of 28 February, established that small hydroelectric power plants operating under the regime previously set out in Decree Law no. 33-A/2005, of 16 February, shall continue to benefit from such remuneration system for a period of 25 years counting from the allocation of the respective operation licence.

A new and specific remuneration regime applicable to the generation by power plants of renewable energy from ocean source or location (offshore wind or waves) using technologies in experimental or pre-commercial stage has been adopted by Order in Council no. 202/2015, of 13 July.

The Order in Council no. 243/2013, of 2 August, as amended by Order in Council no. 133/2015, of 15 May, and Order no. 7875/2017, of 31 August, also establishes the terms, conditions and criteria for allocating injection capacity in the public service electric grid, as well as the licensing procedures to obtain the production licence and respective operating licence.

F.2 Renewable pre-qualifications

From the current legal framework for RES, the following should be highlighted:

- presently, electricity generation is fully open to competition, subject only to obtaining the mandatory licences and approvals for the implementation of the project and carrying out the activity; and
- renewables generation is subject to different licensing requirements and is remunerated according to market prices (although some projects may benefit from special FiTs).

F.3 Biofuel

Decree-Law No. 84/2022, of 9 December, encourages the use of road transport fuels with a higher percentage of biofuel incorporation, as long as the safety of its use is safeguarded.

Decree-Law No. 12/2020, of 6 April, established the legal framework applicable to the trading of licences and the greenhouse effect, transposing Directive (EU) 2018/410.

Decree-Law no. 8/2021, of 20 January, updated the targets for incorporation of biofuels in fuels for consumption on national territory for 2021.

Decree-Law no. 49/2009, of 26 February, provides a specific regime for biofuel promotion mechanisms in road transport, by setting and adjusting minimum mandatory quotas for the incorporation of biofuels in diesel, as well as procedures for their monitoring and control.

Recommendations from the Parliament to the Government have been adopted concerning the reformulation of the public support system to grant access to forest biomass plants according to the sustainable and ecological use of the residual forest biomass, namely to:

- ensure that operation licences for forest biomass plants are granted to plants whose supply: (i) does not use 'energy crops'; (ii) is subject to the fulfilment of the duties for biomass producers; and (iii) is subject to the noise, pollutants, and environmental assessment standards;
- promote resilient agroforestry ecosystems and systems in which residual forest biomass can be incorporated or maintained in soils to avoid the imbalance of ecosystems; and
- review the qualification of biomass plants as projects of potential national interest, considering the problems that arise from the lightening of the implementation process.

G. Climate change and sustainability

G.1 Climate change initiatives

According to different studies[25] and policy circles,[26] Portugal is among the European countries with the greatest vulnerability to the potential impacts of climate change. Several pieces of legislation have been approved and amended in recent years to address these matters:

- Decree-Law no. 68-A/2015, of 30 April, sets out provisions on energy efficiency and cogeneration and establishes an eco-innovation application (ie ECO.AP) to local and regional governments. It transposes the updated EE Directive;
- Resolution of the Council of Ministers no. 28/2015, of 30 April, approved the national strategy for the promotion of economic development based on value creation founded on the conciliation of economic growth and sustainability of the country's competitiveness and its international position as a green growth reference (*Compromisso Crescimento Verde*);
- Resolution of the Council of Ministers no. 56/2015, of 30 July approved the Strategic Framework for Climate Policy, the National Programme for Climate Change 2020/2030, and the National Adaptation Strategy for Climate Change. It also aims to reduce greenhouse gas (GHG) emissions from 18% to 23% by 2020 and from 30% to 40% by 2030 (in comparison to 2005 levels), and is contingent to the results of European negotiations;
- Resolution of the Council of Ministers no.190-A/2017, of 11 December, further approved the action plan for circular economy for the period 2017-2020;
- Law no. 98/2021, of 31 December, that approved the Basic Law on Climate; and
- Decree-Law No. 84/2022, of 9 December, which sets targets for the consumption of energy from renewable sources, partially transposing Directive (EU) 2018/2001.

G.2 Emission trading

Resolution of the Council of Ministers no. 1/2008, of 4 January, approved the National Allocation Plan (ie PNALE II) for the period 2008-2012, as well as the new 2007 targets for policies and measures in the energy supply and transport sectors of the National Programme for Climate Change. Subsequently, the National Programme for Climate Change 2020 to 2030 aims to ensure compliance with the national targets for climate change within the cross-cutting and integrated intervention areas with a view to organising the most appropriate measures for its implementation.

The European Emissions Trading Scheme ("EU ETS") Directive, was transposed by Decree-Law no. 93/2010, of 27 July as amended,[27] and by Decree-Law no. 38/2013, of 15 March,[28] as amended.

The Portuguese Environmental Agency (*Agência Portuguesa do Ambiente*) was assigned the role of Competent Authority, with general coordination responsibilities for the process EU ETS.

G.3 Carbon pricing

The Environmental Fund (*Fundo Ambiental*) was created through Decree-Law no. 42-A/2016, of 12 August, with the objective of financing measures to enable compliance with the State's commitments under the Kyoto Protocol, contributing to the fulfillment of objectives and national and international commitments, particularly those relating to climate change, water resources, waste and nature conservation, and biodiversity.

The Environmental Fund, composed of an autonomous set of assets, without legal personality, depends on the member of the Government responsible for the environment, which is responsible for the strategic management of the environment.

G.4 Capacity markets

Excluding the rules and PSOs described throughout the sections aimed at ensuring that the electricity supply continues to meet demand as more volatile renewable energy generation technologies are implemented, there are no specific rules regulating the capacity market alongside the rules regulating the Energy Market.

H. Energy transition

H.1 Overview

The energy transition is reflected in the various national legislative reforms, where greater use of RES is sought, keeping the goal of a search for greater energy efficiency.

The Basic Law on Climate, approved by Law no. 98/2021, of 31 December, is a landmark regime that evidences the commitment for the energy transition.

According to the Basic Law on Climate, the basic principles on the national energy policy are the following:

a. Decarbonisation of electricity generation, focusing on endogenous renewable resources;

b. Decarbonisation in the residential sector and in public buildings, favouring urban rehabilitation, the profound renovation of the building stock, increasing energy efficiency in buildings and improving thermal comfort, considering for this purpose the neutrality of materials, the adequacy of construction solutions to climate change and the whole life cycle of buildings;

c. Significant reinforcement of energy efficiency in all sectors of the economy, investing in the incorporation of endogenous RES in final consumption of energy;

d. Electrification of energy consumption, eliminating until 2040 the role of fossil gas in the national fossil gas in the national energy system until 2040;

e. Progressive decentralisation and democratisation of energy generation;

f. Decarbonisation of mobility, favouring public transport mobility system active modes of transport, electric mobility and other zero-emission technologies, together emissions, in addition to reducing the carbon intensity of maritime and air transport;

g. Promoting energy transition in the different sectors of economic activity and in particular in industry;

h. Improving air quality indices;

i. Enhancing the principle of climate neutrality in public procurement and specifications; and

j. Combating energy poverty with a view to its eradication.

H.2 Renewable fuels

Hydrogen

Order in Council no. 63/2020, of 14 August, set out the National Strategy for Hydrogen (*Estratégia Nacional para o Hidrogénio*). The key aspects addressed by the strategy are:

- targets for consumption, injection into the transmission network, supply stations and electrolysers capacity for 2020-2030;
- initiatives for the support of production, the regulatory legal framework to be adopted and incorporated in some economic sectors; The Recovery and Resilience Plan ("RRP") is paving the way for green hydrogen, assigning €62 million for 'Investments in Production of Gases of Renewable Origin'. As of October 2022, the RRP is the most prominent platform to stake on projects for the production of hydrogen and other gases of renewable origin for self-consumption and/or injection into the grid.
- opportunities leading to decarbonisation;
- strategy for the value chain;
- financing and supporting mechanisms; and
- the respective implementation phases.

Previously, following the Directive on Alternative Fuels, Decree-Law no. 60/2017, from 9 June, established the framework for the implementation of a national infrastructure for alternative fuels, including hydrogen.

Order no. 98-A/2022, of 18 February, approved the Regulations of the Incentive Scheme in Support of Renewable Hydrogen Production and Other Renewable Gases, which aims to contribute to the objective of carbon neutrality through energy transition by supporting renewable energies, particularly in the production of hydrogen and other renewable gases.

Ammonia

There is currently no legislative framework or regulation on ammonia as an alternative fuel in Portugal.

H.3 Carbon capture and storage

Decree-Law no. 60/2012, of 14 March, transposed the CCS Directive and approved the legal framework applicable to carbon capture and storage.

The following Projects have been executed:

- the KTEJO project, to assess the feasibility of the capture and storage of carbon at the Pego carbon thermal power plant;
- the COMET project, to define an integrated infrastructure for carbon transport and storage in Portugal, Spain and Morocco;
- the CCS PT Road Map, which studied the role of technology within the Portuguese economy;
- the InCarbon Project, to assess the prospective storage of carbon in Alentejo's mafic and ultramafic rocks; and
- the Strategy CCUS Project, for the development of strategic plans for the development of a CCS network in Southern and Eastern Europe.

H.4 Oil and gas platform electrification

Portugal currently has no oil and gas platforms.

H.5 Industrial hubs

The National Hydrogen Strategy (see section H.2) establishes the foundation for the creation and promotion of an industrial cluster around hydrogen until 2030. This industrial cluster is paralleled by the national wind power cluster created between 2005 and 2008, resulting in the installation of two factories (still operating) for the production of wind towers and wind turbine blades. The installation of a factory for the production of electrolysers is a possibility due to the need to meet the demands of the ongoing hydrogen projects and initiatives.

H.6 Smart cities

Order in Council no. 61/2015, of 11 August, approves the main strategies for Smart Cities 2020 (*Cidades Sustentáveis 2020*), namely regarding:

- the assessment of the current state in the growth of urban areas and the evolution of the use of natural resources;
- the promotion of human capital;
- social inclusion and cohesion;
- demographic transformation;
- strategical governance;
- discipline in the use of the soil;
- financial viability;
- urban regeneration;
- sustainability and resilience;
- urban-rural integration; and
- international integration.

Some pilot projects are being implemented in Municipalities across Portugal in order to follow the aforementioned strategies.[29]

I. Environmental, social and governance (ESG)

According to the 2021 report on sustainable finance, published on 13 March 2022, following the consultation procedure carried out by the Portuguese Securities Market Authority (*Comissão do Mercado de Valores Mobiliários*), ESG has had a positive impact on the renewable market sector and among other things, ESG increased investment in clean technology, therefore improving the efficiency of generating renewable energy.

Endnotes

1. Particularly regarding the TSO, Portugal adopted a full private ownership structure. Following a first conditional decision issued in 2014, ERSE issued its final decision on certification of REN (*Rede Eléctrica Nacional*) as TSO on 1 September 2015, after confirmation of compliance with full ownership unbundling (FOU) legal requirements.
2. The Basis of the concession are established in Decree-Law no.15/2022, of 14 January.
3. The Basis of the concession are established in Decree-Law no. 15/2022, of 14 January.
4. Under Article 159 of the Decree-Law no. 15/2022, of 14 January, as amended, and Article 48 of the Decree-Law no. 140/2006, of 26 June, as amended.
5. The low voltage electricity distribution is, historically and exclusively, assigned to municipalities. This may directly develop this activity (direct operation) or transfer the operation to private entities under concession contracts awarded either by the municipalities or by associations of municipalities, following public tender procedures (*concursos públicos*). There are currently 11 concessionaires in mainland Portugal, EDP Distribuição – Energia, S.A. acting as concessionaire in 278 out of 308 municipalities and representing 99.5% of the low voltage clients. The respective concession contracts which, for the most part, have already or will shortly expire (new concessions will be established after a tender process to be implemented by the competent municipalities).
6. Governed by Decree-Law no. 10/2003, of 18 January, as amended the last time by Decree-Law no. 125/2014, of 18 August.
7. Governed by Decree-Law no. 130/2014, of 29 August, as amended the last time by Decree-Law no. 69/2018, of 27 August.
8. Decree-Law no. 97/2002, of 12 April, as amended *inter alia* Decree-Law no. 84/2013, of 25 June, and lastly by Decree-Law no. 76/2019, of 3 June.
9. Approved by Law no. 9/2013, of 28 January, and subsequently regulated by the Regulation on the Procedure for Obtaining Exemption or Reduction of Fines.
10. Such as the Commercial Relations Regulation, the Tariffs Regulation, the Quality Standards of Service Regulation and the Infrastructures Operation Regulation (all available at www.erse.pt).
11. ERSE Regulation no. 561/2014, published on the Official Journal (*Diário da República*) on 22 December (2nd series, no. 246), as amended by Regulation no. 632/2017 published on the Official Journal (*Diário da República*) on 21 December (2nd series, no. 244), which is complemented with extensive sub-regulation approved periodically by ERSE and available at www.erse.pt/pt/electricidade/regulamentos/relacoescomerciais/Paginas/SubRegulamentacaoELRRC.aspx.
12. ERSE Regulation no. 560/2014, published on the Official Journal (*Diário da República*) on 22 December (2nd series, no. 244), as amended by Regulation no. 620/2017 published on the Official Journal (*Diário da República*) on 18 December (2nd series, no. 241), which is complemented with extensive sub-regulation approved periodically by ERSE and available at www.erse.pt/pt/electricidade/regulamentos/acessoasredesaasinterligacoes/Paginas/SubregulamentacaoRARI.aspx.
13. ERSE Regulation no. 619/2017, published on the Official Journal (*Diário da República*) on 18 December (2nd series, no. 241) and also ERSE Directive no. 6/2018, published on the Official Journal (*Diário da República*) on 27 February (2nd series, no. 41) which adopted rules on dynamic tariffs (for pilot projects).
14. Global Use of the System, Use of the Transmission Network in Extra High Voltage and High Voltage and Use of the Distribution Networks in High Voltage, Medium Voltage and Low Voltage.
15. Approved by Law no. 2/2020, of 31 March.
16. Lastly amended by Decree-Law no. 82-D/2014, from 31 December.
17. Annex G to Caracterização da rede nacional de transporte para efeitos de acesso à rede. Situação a 31 de dezembro de 2017.
18. Operators of regional distribution networks (concession holders): Setgás, Lisboagás GDL, Lusitaniagás, Tagusgás, Beiragás and REN Portgás Distribuição, S.A..
19. Operators of local distribution networks (licence holders): Dianagás, Duriensegás, Medigás, Paxgás and Sonorgás.
20. Transposed the Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003 concerning common rules for the internal market in natural gas and repealing Directive 98/30/EC, and was last amended by Law no. 42/2016, of 28 December.
21. Also transposed the Directive 2003/55/EC of the European Parliament and of the Council of 26 June 2003, and was last amended by Decree-Law no. 38/2017, of 31 March.
22. ERSE Regulation no. 435/2016, published on the Official Journal (*Diário da República*) on 9 May (2nd series, no. 89), which is complemented with extensive sub-regulation to be approved periodically by ERSE and available at www.erse.pt/pt/gasnatural/regulamentos/acessoasredesinfraestruturaseasinterligacoes/Paginas/SubregulamentacaoGNRARII.aspx.
23. ERSE Regulation no. 225/2018, published on the Official Journal (*Diário da República*) on 16 April (2nd series, no. 74).
24. ENTSOG – The European Natural Gas Network (Capacities at cross-border points on the primary market) 2017, available at www.entsog.eu/sites/default/files/2018-09/ENTSOG_CAP_2017_A0_1189x841_FULL_064.pdf.
25. Climate Impacts in Portugal, 2019. Available at www.youth4climatejustice.org/wp-content/uploads/2021/01/Climate-Analytics-Climate-Impacts-in-Portugal-min.pdf.
26. President von der Leyen Speech in the Plenary of the European Parliament, 18 December 2019, available at www.ec.europa.eu/commission/presscorner/detail/en/speech_19_6802.
27. As amended by Decree-Law no. 195/2015, of 14 September, that partially transposes the New EU ETS Directive, Decree-Law no. 42-A/2016, of 12 August, and Law no. 12/2022.
28. Also completing the transposition of the New EU ETS Directive. Repeals Decree-Law no. 233/2004, of 14 December 2004, that remains in force until 30 June 2013 or until the completion of all procedures for the period 2008-2012 as per the provisions on monitoring and annual reporting of emissions, the return of emission allowances and procedures at the level of the Registration of Emissions Licences.
29. See www.smart-cities.pt.

Energy law in Romania

Recent developments in the Romania energy market

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Power price interventions and tax on windfall profits

The Emergency Government Ordinance no. 27/2022 EGO ("EGO 27/2022") which extended the support measures for consumers and the windfall taxation of energy generators from April 2022 to March 2023 due to the persistence of surging energy prices, was recently amended by the Emergency Government Ordinance no. 119/2022 ("EGO 119/2022"), which was enacted and published on 1 September 2022.

EGO 119/2022 amends some of the compensation measures that were applicable during the 2021 to 2022 winter and extends their applicability from 1 September 2022 to 31 August 2023.

Furthermore, EGO 119/2022 replaces the windfall taxation due by energy generators with a more burdensome contribution to the Energy Transition Fund ("ETF Contribution") equal to 100% of the additional revenues generated from electricity sales (after having deducted cost with physical acquisitions of electricity and balancing costs) from 1 September 2022 to 31 August 2023. EGO 119/2022 also imposes an additional ETF Contribution on energy and natural gas producers, energy aggregated generators, traders and suppliers performing trading activities and aggregators trading electricity and natural gas on the wholesale market, equal to 98% of the difference between the monthly weighted average sale price and the monthly weighted average purchase price of energy or natural gas. This is applicable from 1 September 2022 to 31 August 2023.

Development of small-scale nuclear power plants

In 2020, Romania and the US executed an intergovernmental agreement ("IGA") on nuclear power, ratified by the Romanian Parliament with Law no. 200/2021. The US Exim Bank expressed its interest in a Memorandum of Understanding ("MOU") executed with the Romanian Ministry of Energy to finance large investment projects in Romania, including in the nuclear field, with an aggregate value of US$7 billion.

Following completion of the IGA, NuScale and Nuclearelectrica (the Romanian nuclear power company) are planning to implement Romania's first NuScale nuclear plant by 2030, featuring six modules with a capacity of 462MWe. In May 2022, Nuclearelectrica, NuScale and E-Infra executed a MoU for the development of the first small scale modular reactor. On the basis of a study conducted by Nuclearelectrica (financed with a United States Trade and Development Agency grant), the location of the first SMR was identified, ie Dambovita county, on the site of the former Doicesti thermal power plant.

New renewables investment support scheme

On 31 March 2022, the Romanian Ministry of Energy launched a call for projects under a new state aid scheme for supporting the development of new wind and solar power plants, with or without integrated power storage capacities (the "Support Scheme").

This is the first support scheme launched for financing renewables projects under Ro-mania's recovery and resilience fund. It has a €457m budget, of which €382m is for wind and solar projects with over 1MW installed capacities and €75m for wind and solar projects with installed capacities ranging between 0.2MW and 1MW.

Proposed projects must also fulfil certain eligibility criteria, the most important being:

- only new wind and solar power plants (with or without integrated energy storage capacities) are eligible, therefore, re-powering projects or extensions of existing wind or solar power plants are not eligible under this scheme;
- eligible projects must use one single technology (ie no mixing of wind and solar); however, integrated storage capacities are eligible for up to 20% of the state aid value;
- implementation starts no earlier than the date the tender documents are submitted and ends no later than 30 June 2024;
- projected installed capacity over 0.2MW;
- total state aid value cannot exceed €15m per enterprise or project;
- the state aid value per MW cannot exceed €650,000/MW for wind projects and €425,000/MW for solar projects, in case of installed capacities in excess of 1MW; and €1,300,000/MW for wind projects and €750,000/MW for solar projects, in case of capacities between 0.2MW and 1MW (inclusive);
- a technical connection permit is issued prior to executing the financing agreement; and
- ownership or use right on the project land necessary for the development, construction and operation of the project is secured.

The state aid funds are granted per project, therefore applicants must demonstrate the unitary nature of their project which, once funded, cannot be split-off or otherwise re-configured.

Applicants may register one or more projects in the competitive tender proceedings for receiving funding under the Support Scheme, provided such projects do not qualify as a 'sole investment project'.

The Support Scheme funds are awarded through competitive tender proceedings. Therefore, submitting an offer does not guarantee automatic selection for financing. Nevertheless, investors have the opportunity to re-submit an offer within further tender calls if the project is not implemented before re-submission.

Investors were called to submit applications between 31 March 2022 and 31 May 2022. The call for projects is now closed and the authority is currently assessing submissions. Further tender calls will be available next year.

Contract for Difference (CfD) support scheme in the making

In spring 2019, the Romanian Ministry of Energy announced their intention to implement a new mechanism for supporting low-carbon electricity generation in the form of a CfD scheme.

This intention was further formalised in June 2020, when the Romanian Government ("Government") approved the key principles of the CfD scheme by way of a Memorandum, thus showing broad governmental support for this initiative. The proposed new scheme is inspired by the British CfD system, targeting both the renewables and the nuclear sector.

Eligible generators enter into a private law contract (CfD contract) with the nominated counter-party and agree on a 'strike price'. Generators sell electricity on the competitive market via a route-to-market power purchase agreement ("PPA") or on the centralised power exchange. If the market price (reflected in the so-called 'reference price') falls below the strike price, the counterparty will reimburse generators the difference. Likewise, if the market price exceeds the strike price, the generators will reimburse the difference to the counterparty.

In 2021, the Government appointed a team of consultants to structure the scheme and implement it. It is expected that the CfD scheme will go live in 2023. Since the implementation of the CfD scheme requires authorisation by the EU Commission ("Commission"), credibility of the timeline advanced by the Government is currently being questioned by the market.

Repeal of the ban on PPAs

On 31 December 2021, Emergency Government Ordinance no. 143/2021 amending the Romanian Energy Law no. 123/2012 (the "Energy Law") and other normative acts ("EGO no. 143/2021") was enacted. GEO no. 143/2021 transposes under local law Directive (EU) 2019/944 on common rules for the internal market for electricity and amending Directive 20212/27/EU ("Directive 2019/944"). A key change to the Energy Law is the repeal of the ban on bilateral PPAs.

As a particularity of the Romanian energy market, over-the-counter wholesale trading of elec-tricity has been banned since 2012, greatly discouraging the development of additional capaci-ties. All wholesale transactions have been running ever since (with limited exceptions) on the platforms of the centralised power market operated by OPCOM, the Romanian Electricity and Gas Market Operator.

Romania's energy watchdog interpreted the ban on bilateral wholesale trading in a restrictive manner as also prohibiting the export of electricity by generators on centralised markets in neighbouring countries. The matter was settled by the Court of Justice of the European Union ("CJEU") in 2020, in the sense that a national regulation imposing the obligation to trade electricity on a single platform, and therefore, restricting generators from exporting electricity directly to other Member States, was seen as a measure having equivalent effect to a quantita-tive restriction on exports that could not be justified on grounds of public security connected to the security of energy supply, insofar as such legislation was not proportionate to the objective pursued.

In 2020, the execution of PPAs for new investments that go online after 1 June 2020 was formally enabled but was still considered problematic for existing power plants.

With the enactment of GEO no. 143/2021, the conclusion of bilateral PPAs by electricity generators is no longer restricted, regardless of the commissioning date of the power plant. This amendment is in line with both Regulation (EU) 2019/943 on the internal market for electricity, which allows for long-term electricity supply agreements negotiable over-the-counter, and Directive 2019/944. The aforementioned amendment also clarifies previous legislative uncertainties on the matter.

Infringement proceeding against Romania for failure to adopt emergency plan

The Commission has referred Romania to the CJEU for failing to adopt an emergency plan under the EU Security of Gas Supply Regulation (EU) No 994/2010. The regulation aims to ensure that Member States are well prepared to deal with possible supply disruptions. To this end, Member States, amongst others, must prepare emergency plans and notify them to the Commission. An emergency plan sets out measures and procedures that come into effect in case of gas supply disruption and which are well coordinated with neighbouring Member States. Member States had to adopt these plans by 3 December 2012. In November 2013, the Commission sent a letter of formal notice to Romania as it had not adopted its national emergency plan. In November 2014, the Commission proceeded to a reasoned opinion as Romania still failed to comply with the Security of Gas Supply Regulation. There is still no emergency plan in place which may jeopardise Romania's ability to deal with a possible crisis situation.

Overview of the legal and regulatory framework in Romania

A. Electricity

A.1 Industry structure

Nature of the market

The Romanian electricity market has been gradually liberalised since 1 July 2007, with full liberalisation effectively achieved as of 1 January 2018. Gradual restructuring has occurred since 1990, when the largest vertically integrated electricity companies, ie RENEL and CONEL, were devolved into:

- the main electricity generators, ie Hidroelectrica SA, Termoelectrica SA and Nuclearelectrica SA (established in 1998);
- the transmission system operator ("TSO"), ie Transelectrica SA; and
- suppliers and distributor, ie Electrica SA and its subsidiaries.

Key market players

The transmission system is operated by one single operator (ie Transelectrica SA), whereas the distribution system is operated by six operators: Delgaz Grid, Distributie Energie Oltenia, E-Distributie Muntenia, E-Distributie Banat, E-Distributie Dobrogea and Distribuție Energie Electrica Romania.

Numerous private entities are also active in the field of electricity generation and supply. According to the Romanian Energy Regulatory Authority (*Autoritatea Nationala de Reglementare in Domeniul Energiei Electrice*) ("ANRE"), as of November 2021, there were 94 suppliers and traders licensed to operate in Romania and some 121 generators licensed to operate dispatchable power plants.

The electricity market is operated by OPCOM SA, a licensed state-controlled entity that operates the energy exchange.

Regulatory authorities

The Ministry of Energy ("ME") is in charge of setting electricity strategy and policies.

ANRE is the sole national regulatory authority ("NRA") responsible for regulating and monitoring the electricity and gas markets. ANRE is an autonomous public institution under parliamentary control, financed entirely from its own resources.

Legal framework

Law no. 123/2012 on electricity and natural gas ("Energy Act") came into force on 19 July 2012. Substantial amendments were recently brought to the Energy Law with a view to align it with the EC Directive 2019/944 on common rules for the internal market for electricity.

The Energy Act regulates all activities in the energy domain. Law no. 220/2008 on the promotion of renewable energy generation[1] ("Renewable Energy Act") regulates the incentives regime applicable to renewable energy plants commissioned by 31 December 2016.

Implementation of EU electricity directives

Romania has implemented the full ownership unbundling model through the Energy Act, which transposes the Third Electricity and Gas Directives. The TSO fully unbundled its transmission and system activities from generation and supply activities in 2000. Transelectrica SA is a public listed company in which the Romanian State holds a stake of about 59% via the Ministry of Economy, Commerce and Relations with the Business Environment ("MECBE"). As a general rule, the transmission network is the public property of the Romanian State, but the TSO may acquire transmission assets.

A.2 Third party access regime

Generally, access to all assets in the public or private ownership of the Romanian State and services of national interest in the electricity sector may be granted to private parties by concession.

Generators and customers are granted regulated access to the public power network on payment of a regulated tariff. Under the Renewable Energy Act, renewable electricity benefitting from the support scheme receives guaranteed access to the network.

A.3 Market design

See sections A.1, A.2, and C.1.

A.4 Tariff regulation

On the domestic electricity market, the following prices and tariffs apply:

- negotiated prices on the competitive market; and
- regulated tariffs for:
  - transmission and distribution;
  - the last resort supply of electricity to end customers whose supplier may no longer supply electricity, for various reasons, such as insolvency, revocation of licence, etc;
  - the acquisition of technological system services and network connections; and
  - the operation of the centralised markets.

Regulated prices and tariffs are determined by ANRE based on specific calculation norms. ANRE considers the justified costs for each of the regulated activities, together with investment costs, environmental protection costs and a 'reasonable profit margin' when setting tariffs. In the tariff-setting process, market participants submit their pricing and tariff proposals to ANRE, based on the calculation rules. ANRE then approves by way of order and publishes the regulated prices and tariffs in the Romanian Official Gazette.

A.5 Market entry

Activities in the electricity sector may only be carried out based on authorisations and licences issued by ANRE. ANRE may grant, amend, suspend or withdraw authorisations and licences in the electricity sector.

Applications for authorisations or licences must be accompanied by supporting documentation,[2] including corporate documents, financial statements, feasibility studies, proof of funds and performance guarantees. Once the complete documentation has been submitted, ANRE will decide whether to grant an authorisation or licence within 60 days. For renewable energy and high efficiency cogeneration projects, ANRE issues its decision within 30 days. An administrative fee is payable for the grant of authorisations or licences. In addition, licensees must pay ANRE annual contributions calculated as a percentage of their annual turnover derived from electricity and thermal power activities. No special authorisation regime was enacted yet for offshore electricity projects.

Domestic authorisation or licence holders are companies established in Romania. Except for electricity supply and trading, foreign entities must set up at least a secondary seat in Romania (ie a presence without legal personality, such as a branch or representative office) as a pre-requisite for applying for an authorisation or licence.

ANRE has lifted barriers to electricity supply and trading activities for European Union ("EU") operators by:

- eliminating the requirement of having a permanent establishment in Romania as a pre-requisite for obtaining the licence; and
- eliminating the requirement of holding a licence issued in Romania for those operators licensed in other EU Member States, subject to a statement on the compliance with technical and commercial rules applicable in Romania.

Any electricity-related activity is subject to ANRE's authorisation or licensing procedure, namely:

- establishment authorisations (*autorizatie de infiintare*) are required for setting up new energy facilities or revamping existing facilities; and
- licences are required for:
  - electricity generation (*licenta pentru exploatarea comerciala*);
  - transmission (*licenta pentru prestarea serviciului de transport al energiei electrice*);
  - system operation (*licenta pentru prestarea serviciului de sistem*);
  - distribution (*licenta pentru prestarea serviciului de distributie a energiei electrice*);
  - centralised market operation (*licente pentru administrarea pietelor centralizate*), a single licence is granted for the energy market operator and a single licence for the balancing market operator;
  - supply (*licenta pentru activitatea de furnizare a energiei electrice*);
  - electricity trading (*licenta pentru activitatea traderului de energie electrica*);
  - aggregation activities (*licenta pentru activitatea de agregare*); and
  - operation of storage facilities not attached to an existing power plant (*licenta pentru exploatarea comercială a instalațiilor de stocare a energiei*).

The duration of an authorisation is at least one year and will vary according to the time required for the relevant works. Electricity supply, electricity trading and aggregation licences are valid for a period of ten years and all other licences are valid for 25 years.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Authorisation and licence holders have various obligations relating to the safety, quality and price of electricity supplied; continuity of supply; energy efficiency; labour security and health norms; and environmental norms in addition to their direct contractual obligations to their customers. PSOs may be established by the Romanian Government ("Government") or by ANRE through specific regulations or conditions attached to authorisations and licences. The Government notifies the European Commission ("Commission") of all measures adopted for satisfying universal service and PSOs and of their potential impact on national and international competition.

Smart metering

Smart-metering system are being rolled-out on the basis of a schedule approved by ANRE by way of the Decision no. 778/2019 for the period 2019 to 2028. The schedule was prepared on the basis of projects presented by distribution system operators ("DSOs") that considered cost-benefit analysis. Such analysis describes in detail how mandatory functionalities of the system work, and the benefits offered to end consumers. Minimum functional and technical requirements applicable to smart-metering systems are adopted by ANRE.

ANRE's implementation schedule will ensure that smart metering systems are installed for end-consumers by 1 January 2024 and 31 December 2028 respectively, depending on an annual consumption threshold defined by the regulator which varies throughout the distribution regions.

Electric vehicles

Directive 2014/94/UE on the installation of alternative fuels infrastructure, transposed by Law no. 34/2017 and Government Decision no. 87/2018, requires Member States to develop the infrastructure sector for supplying alternative fuel vehicles and to ensure mobility and interoperability based on these types of fuels.

Interest for electric vehicles ("EVs") in Romania is on the rise. In 2021, the number of EVs registered in Romania has doubled, reaching an overall still modest number of 10,000 EVs. Infrastructure has also seen a rapid growth, with some 1,000 charging stations as of 2021.

The Ministry of Environment continues the incentives program for the acquisition of EVs (so-called 'Rabla Plus' program), whereby the acquisition of EVs is partially supported through the Environmental Fund, by offering a subvention of around to €10,000 per EV and of around €4,500 per hybrid vehicle which generates carbon dioxide ("CO_2") emissions of less than 80g/km in exchange for used vehicles. Incentives of around €4,500 are also available for electric motorcycles.

To support investments in the infrastructure, the Ministry of Environment has recently launched a financing program amounting to some €100 million for charging infrastructure for the public sector (municipalities, public institutions, etc).

A.7 Cross-border interconnectors

Romania currently has the following interconnectors:

Romania-Bulgaria:

- Overhead line 400kV Isaccea – Dobrudja;
- Overhead line 400kV Țânțăreni – Kozlodui;
- Overhead line 400kV Isaccea – Varna; and
- Overhead line 220kV Ișalnița – Kozlodui.

Romania-Serbia:

- Overhead line 400kV Porțile de Fier – Djerdap;
- Overhead line 110kV Ostrovul Mare – Kusjak;
- Overhead line 110kV Gura Văii – Șip; and
- Overhead line 110kV Jimbolia – Kikinda.

Romania-Hungary:

- Overhead line 400kV Arad – Sandorfalva; and
- Overhead line 400kV Nadab – Bekescsaba.

Romania-Ukraine:

- Overhead line 400kV Roșiori – Mukacevo; and
- Overhead line 700kV Isaccea – Ucraina Sud.

Romania-Moldova:

- Overhead line 400kV Isaccea – Vulcănești;
- Overhead line 110kV Stânca – Costești;
- Overhead line 110kV Huși – Cioara;
- Overhead line 110kV Țuțora – Ungheni; and
- Overhead line 110kV Falciu – Gotesti.

Projects:

- Overhead line 400kV Romania – Serbia (Reșița – Pancevo);
- Overhead line 400kV Suceava – Bălți (Moldova);
- Submarine cable (HVDC Link 400kV) Romania – Turkey; and
- Overhead line 400kV Iași – Strășeni – Ungheni (Moldova) (alternatives, Strășeni-Ungheni 330kV or 400kV and Ungheni-Iași 400kV).

Interconnection capacity for the importation of electricity is allocated based on auctions according to European rules. Private parties who are not a TSO cannot operate interconnectors.

B. Oil and gas

B.1 Industry structure

Nature of the market

Although Romania was the first country in the world to have officially registered oil production, which caused the national economy to heavily rely on the oil industry, currently, the total quantity of oil produced in Romania is not sufficient to cover national consumption. Romania resorts to importing oil, with the main sources being Russia, Kazakhstan and Azerbaijan.

According to the Commission's statistical data, in 2020, Romania imported up to 68% of the needs of the existing refineries, which still places Romania among the less import dependant countries in the EU.

On the Upstream segment, OMV Petrom produces almost the entire quantity of Romania's oil and also processes the whole quantity of oil extracted from Romania plus imported oil.

OMV Petrom is also the leader in the oil distribution market, followed by Rompetrol, Lukoil, MOL, SOCAR and Gazprom.

Following an investigation finalised in 2019 into the fuel market, to increase competition on this segment, the Competition Council launched a price monitoring app, which covers the largest fuel chains around the country.

Romania is a gas importer, with Russia being the main source of imported gas. In 2020, imported gas accounted for 18.79%[3] of energy consumption in Romania.

Romania's natural gas market underwent gradual restructuring after 1990. In 1997, the municipal enterprises (*Regii Autonome*) were restructured as national companies and privatised. In 2000, SNGN ROMGAZ SA was divided into five separate state-owned companies, ie:

- DISTRIGAZ SUD SA Bucharest, responsible for supply and distribution;
- DISTRIGAZ NORD SA Targu-Mures, responsible for supply and distribution;
- EXPROGAZ SA Medias, responsible for production and storage;
- DEPOGAZ SA Ploiesti, responsible for storage; and
- TRANSGAZ SA Medias, responsible for transportation and transit on Romanian territory.

In 2001, 10% of the gas market was liberalised, with further liberalisation taking effect in 2002. Complete liberalisation was achieved in July 2007 under Government Decision no. 638/2007.

Key market players

ROMGAZ is the largest Romanian natural gas producer, followed by OMV PETROM, both covering 95% of the domestic gas consumption. Storage facilities are owned by ROMGAZ and DEPOMURES.

The national TSO is TRANSGAZ, a public joint stock company which is 58.5% state-owned while 41.5% is held by private entities.

The distribution of natural gas is carried out by several companies, including DISTRIGAZ SUD, DISTRIGAZ NORD and PETROM.

Regulatory authorities

ANRE is the regulatory authority for the natural gas[4] sector (as well as the electricity sector). Natural gas transmission and distribution services are public services of national interest (with the exception of closed distribution systems). Natural gas distribution is subject to licensing under a concession arrangement. The national transportation system ("NTS") is public property.

Legal framework

The gas market is primarily regulated by the Energy Act. Natural gas policy is set out in a government programme, approved by the Romanian Parliament. The Energy Act provides that an end customer can only consume natural gas and is prohibited from reselling it. The natural gas market was fully liberalised as of 1 July 2021.

Implementation of EU gas directives

The Third Gas Directive has been implemented through the Energy Act and Romania has chosen to implement the Independent System Operator (ISO) unbundling model.

B.2 Third party access regime to gas transportation networks

Third party access to upstream pipelines, storage facilities, TSO, DSO, and liquefied natural gas ("LNG") facilities is regulated and granted in accordance with the relevant legislation.

Access to upstream pipelines and the transmission network is only available to:

- holders of a distribution concession;
- operators of LNG terminals;
- operators of underground storage facilities;
- new industrial customers;
- holders of distribution licences;
- natural gas producers; and
- other customers that cannot access the distribution system in their area.

Access to natural gas facilities may be refused where:

- there is insufficient capacity;
- access to the facility would impede public service and safe exploitation obligations;
- granting access to the facility would trigger important technical and/or economic difficulties for the licensee in relation to 'take-or-pay' agreements it has entered into; or
- the natural gas to be injected does not reach the requisite quality set out in the applicable regulations.

Refusals to grant access must be given in writing and include reasons for the decision.

Public property assets related to natural gas transmission and storage objectives or systems, as well as natural gas transportation, storage and distribution services are subject to concession arrangements for Romanian and foreign legal entities.

B.3 LNG terminals and gas storage facilities

There are currently no LNG terminals in Romania, but according to the Transgaz development plans, a terminal is planned to be developed by 2026 at the Black Sea.

The Technical Code for LNG[5] sets out the minimal technical conditions for LNG and the competent authorities regulating the storage, transportation, distribution, and utilisation of LNG. ANRE grants authorisations or licences for LNG related activities according to the provisions of Order no. 199/2020. ANRE has recently regulated through Order no. 90/2018 the framework licence conditions for LNG supply.

B.4 Tariff regulation

ANRE sets regulated prices and tariffs for regulated activities (transmission, distribution, storage, supply of last resort, use of LNG and hydrogen terminals) based on its approved and published calculation methods. ANRE's orders approving the regulated prices and tariffs, and their calculation methodologies, are published in the Romanian Official Gazette.

The regulated gas supply prices have been fully eliminated for all consumers, including household consumers, as of 1 July 2021.

On the competitive gas market, prices are established on a competitive basis, based on supply and demand. Participants may enter into wholesale and retail transactions.

The wholesale competitive gas market functions based on bilateral agreements concluded between economic operators who are participants to the gas market, as well as based on transactions on the centralised markets, while on the competitive retail gas market, suppliers sell natural gas to end customers based on negotiated agreements or standard offers.

Following a recent amendment to the Energy Act, the natural gas producers and their affiliates, as well as licensed suppliers, are under an obligation to enter into transactions on the Romanian centralised market in a transparent and non-discriminatory manner, in order to buy or sell a minimum quantity of natural gas.

B.5 Market entry

Activities in the gas sector can only be carried out with the appropriate authorisations or licences from ANRE.

Authorisations must set up upstream pipelines, new storage facilities, biogas or biomethane generation facilities, new TSO or DSO and LNG, biogas and biomethane production facilities, direct pipelines (*magistrale directe*) and hydrogen production facilities.

Licences are required for:

- supply of natural gas, biogas or biomethane, LNG, CNG, CNCV and liquid petroleum gas ("LPG");
- operation of storage, distribution and transport systems;
- operation of upstream pipelines;
- operation of LNG terminals;

- operation of hydrogen production facilities; and
- operation of the centralised markets.

Domestic authorisation or licence holders are companies established in Romania. Foreign authorisation or licence holders must establish at least a secondary seat in Romania (ie a local presence without legal personality, such as a branch or representative office) in order to receive an authorisation or a licence.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Under the Energy Act, the licenses and authorisations issued by ANRE for gas storage, transport, distribution, supply and operation of the platform regarding LNG, as well as direct contracts with customers, provide numerous obligations regarding, ie the continuity of supply, safety, quality, energetic efficiency, labour security, health and environmental norms.

ANRE may determine PSOs for each natural gas activity, applicable to all licence or authorisation holders, in a transparent, equidistant and non-discriminatory manner, that must not impede the liberalisation of the natural gas market, nor constitute borders for new operators to enter the market or distort competition and transparent functioning of the market. If, however, such obligations were likely to affect the natural gas market, they would be subject to notification of the Competition Council.

Every two years, ANRE re-examines the necessity and the way of imposing the PSOs, taking the evolution of the natural gas sector into account.

ANRE submits a report regarding measures taken for fulfilling the PSOs to the Prime Minister and the Resort Ministry. For information purposes, this report is also sent to the Commission and the specialised committees of the Romanian Parliament.

Smart metering

Under the Energy Act, ANRE must assess the implementation of intelligent metering systems that contribute to the active participation of consumers in the gas supply market, from the perspective of long-term costs and benefits for the market and for individual consumers.

If such an assessment is successful, meaning that the implementation of the smart metering systems is beneficial for the natural gas market, ANRE must issue an implementation calendar. However, no such calendar has been issued by ANRE so far.

B.7 Cross-border interconnectors

There are several physical points of connection with neighbouring transmission systems:

- Csanádpalota/FGSZ (HU);
- Ruse-Giurgiu/Bulgartransgaz (BG);
- Ungheni/Vestmoldtransgaz (MD);
- Negru Voda 1/Bulgartransgaz (BG);
- Negru Voda 2/Bulgartransgaz (BG);
- Negru Voda 3/Bulgartransgaz (BG);
- Mediesu Aurit Import/Ukrtransgaz (UA);
- Isaccea Import/Ukrtransgaz (UA); and
- Isaccea 1,2,3/Ukrtransgaz (UA).

C. Energy trading

C.1 Electricity trading

The Energy Act defines the participants in the Romanian electricity market as comprising:

- generators;
- the TSO;
- the market operator (OPCOM SA, a subsidiary of Transelectrica SA);
- the DSOs (Delgaz Grid, Distributie Energie Oltenia, E-Distributie Muntenia, E-Distributie Banat, E-Distributie Dobrogea and Distribuție Energie Electrica Romania);
- suppliers and traders;
- aggregators and storage operators;
- the electricity; and
- customers.

The electricity market is fully liberalised. Transactions are classified as wholesale or retail.

As a particularity of the Romanian energy market, over-the-counter wholesale trading of electricity has been banned since 2012. This ban was recently fully lifted by an amendment to the Energy Act. As such, transactions on the competitive market are currently made bilaterally or on the centralised platforms operated by the Romanian electricity and gas exchange, OPCOM SA ("OPCOM").

Currently, the OPCOM market features two spot platforms, ie the day-ahead market (*Piața pentru Ziua Următoare*) and the intra-day market (*Piața Intra-zilnică*), the latter becoming increasingly liquid following the market coupling in 2019, when the Single Intraday Coupling expanded to Romania.

OPCOM operates several forward platforms which generally standardised as concerns the delivery profile, the offered power or the delivery periods.

Suppliers of last resort must ensure the supply of electricity in quality conditions and with reasonable, transparent, easily comparable, and non-discriminatory prices according to ANRE regulations.

The current Romanian legislation in the energy sector does not allow the use of International Swaps and Derivatives Association (ie ISDA) standard instruments. The Competition Council noted in its report on the results of the electricity sector investigation that the Energy Act should be amended so as to allow the use of financial instruments, in order for the Romanian electricity market to be able to operate as a developed market.

The Government may intervene in the prices applied to vulnerable or energy poor consumers, subject to notifying the Commission. Market intervention should observe certain principles, eg should be transparent non-discriminatory, should ensure equal access to clients, be limited in time and proportional as concerns their respective beneficiaries and not generate additional cost to market participants in a non-discriminatory manner.

The balancing market functions within the wholesale market and is operated by the Balancing Market Operator, ie Transelectrica SA. In this capacity, Transelectrica SA purchases electricity from, and sells electricity to, market participants with a view to compensating them for any deviation from scheduled generation or consumption capacities.

EU market coupling

As of November 2014, the Romanian Day-Ahead electricity market was firstly coupled with the spot markets of Hungary, Slovakia, and the Czech Republic (as part of the 4M MC project). In 2021, the Day-Ahead market switched to the European coupled mechanism operation with the implementation of the DE-AT-PL-4M MC project, also known as Interim Coupling. Starting with 2019, the Single Intraday Coupling expanded to Romania and the Intraday market started to operate in coupled system with 22 European countries.

The electricity market is balanced by way of the day-ahead market, the intra-day market and the balancing market.

Transactions on the Day-Ahead market are concluded by matching the offers of buyers and sellers through an auction mechanism established in accordance with the mechanism for price coupling of the regional markets. OPCOM is the counterparty for every market participant in transactions concluded on the day-ahead market.

On the Intraday market, firm hourly transactions with electricity are executed for each day of delivery from the day before the day of delivery, after the completion of transactions on Day-Ahead Market and up to one hour before the start of delivery or consumption.

The balancing market is a compulsory market operated by the TSO. On the balancing market, the TSO buys or sells active electricity from or to market participants that reach the dispatching producer or consumer limit. On the balancing market, the gate closes at 5pm of the trading day. Physical notifications are transmitted to the TSO no later than 3pm on the trading day, preceding the delivery day.

C.2 Gas trading

The domestic gas market is fully liberalised. Transactions are classified as wholesale or retail.

In the wholesale market, transactions are concluded bilaterally between market participants or via the centralised market. In the retail market, suppliers sell natural gas to end consumers based on negotiated agreements or standardised offers.

The natural gas generators and licensed suppliers are under an obligation to enter into transactions on the Romanian centralised market in a transparent and non-discriminatory manner, in order to buy or sell a minimum quantity of natural gas, as established by the regulator, ANRE. Under the provisions of the Energy Act, this obligation applies until 31 December 20.

In case of a major imbalance between offer and demand or of market disfunctions on the natural gas market, the Government, at the proposal of ANRE and with the endorsement of the Competition Council, can limit or freeze prices and tariffs for a maximum of six months, which can be consecutively extended by three month periods as long as the respective circumstances persist.

The Code of the National Natural Gas transportation network was approved and came into force on 1 April 2013 under ANRE Order no. 16/2013.

Legal entities in the natural gas market carrying out more than one regulated activity must ensure that their accounts (revenue and expenditure for each activity) are separated.

D. Nuclear energy

Romania has signed and ratified the majority of the international conventions and treaties on nuclear energy and has developed a legislative framework to implement them.

Nuclear activities are mainly regulated by Law no. 111/1996 on the safe functioning, regulation, authorisation, and control of nuclear activities performed exclusively for peaceful purposes. The National Commission for Nuclear Activities Control (*Comisia Nationala pentru Controlul Activitatilor Nucleare*) ("CNCAN") is the national authority in the nuclear field. CNCAN issues secondary legislation, including authorisation and control procedures for nuclear activities. The management of used nuclear fuel and radioactive waste, including final depositing, is regulated by Government Ordinance no. 11/2003. Radioactive emissions from nuclear and radiological installations are monitored according to the standards approved by CNCAN Order no. 276/2005.

Government Ordinance no. 7/2003 regarding the use of nuclear energy exclusively for peaceful purposes established the Nuclear Agency as the competent authority responsible for the strategy for the development of the nuclear sector, the action plan and the National Nuclear Plan (*Planul Nuclear National*) ("PNN"). The PNN is the instrument through which the Government carries out long-term general policies in the nuclear field.

Romania's only nuclear power plant is located in Cernavoda, in south-east Romania. The plant has two units that generate about 20% of the country's total electricity generation.

Over the years, Romania has been discussing with various investors the potential cooperation for the construction two additional units at the existing Cernavoda nuclear power plant, Units 3 and 4. In 2020, an extended intergovernmental agreement was executed with the United States, covering amongst others, cooperation in the civil nuclear sector and in particular in respect to Units 3 and 4.

E. Upstream

Romania has an active upstream oil and gas sector. In 2012, the industry was boosted by the discovery of a natural gas field in the Black Sea (containing about 42 to 84 billion cubic metres ("bcm") of reserves). In 2015, about 30bcm of offshore reserves were discovered, raising hope that Romania can become an energy security pole in the region.

The sector is mainly regulated by Law no. 238/2004 ("Oil Act"), as implemented by methodology norms ("Norms"). The competent authority in this field is the National Agency for Mineral Resources (*Agentia Nationala pentru Resurse Minerale*) ("ANRM"), a specialised Governmental body.

Under the Oil Act, oil reserves are the exclusive public property of the State. The oil transmission network is also public property and considered to have strategic importance to Romania. Investments in the transmission network from public funds are not subject to amortisation. Conversely, privately financed investments made by a concession holder become public property but are subject to amortisation.

Law no. 258/2018 ("Offshore Law") sets out a specific legal regime for oil and gas exploration and production in the Black Sea offshore perimeters. The Offshore Law aims to fill a legislative gap, the existing legal framework being tailored mainly for oil and gas onshore operations. The Offshore Law has not offered sufficient comfort to investors and thus investment decisions on certain existing offshore explorations are blocked. To address investors' concerns, the Offshore Law was amended in May 2022, bringing long-awaited certainty and stability as concerns the royalty and specific tax regime in force as of 1 January 2023.

Transit

Oil transit is performed on contractual basis, by way of agreements negotiated between States. Such agreements should not include unjustifiably restrictive clauses or endanger security of supply and quality of services, and must have regard to the available reserves, storage capacity and the efficiency of the management of the existing system.

Transportation

Oil transportation is a public service of national and strategic significance performed for transmission tariffs set by ANRM. The concessionaire for the transmission network is regarded as a 'common' TSO and must ensure free access to available system capacity for all market participants and authorised legal persons under equal, non-discriminatory and transparent terms. Access may only be refused in limited circumstances (such as lack of capacity, system security or a failure to meet oil quality standards) and any such refusal must be communicated to ANRM and to the applicant in writing and state the reasons for refusing access. The 'common' TSO should be independent and separated from any entities involved in exploration, development and exploitation activities.

Concessions

Oil operations and related public assets are subject to concessions granted under the rules laid down by the Oil Act and the Norms. The Government approves concessions for the following activities:

- exploration-development-exploitation;
- development-exploitation;
- exploitation;
- underground storage of natural gas;
- operating the national pipelines system; and
- operating oil terminals.

Exploration may be separately carried out on the basis of a non-exclusive permit, issued by ANRM on receipt of a written request, which will cover a defined geographic area. The permit is valid for a maximum of three years, without any extension rights.

The concession award process may be initiated by the authority or by private legal entities. ANRM determines the list of perimeters for the execution of the concessionary oil operations, as well as the necessary assets for these operations. The list is published in the Romanian Official Gazette and the Official Journal of the EU, and public tenders are then held. Offers submitted in response to the tenders should include an exploration/development-exploitation/exploitation programme (as the case may be) detailing the works and respective schedule, proofs of financial and technical good standing, an environmental impact assessment and recovery plan, details of personnel training and a know-how transfer programme. The winner of the tender process enters into a concession agreement, which becomes binding when Governmental approval has been granted. The provisions of the agreement remain in full force and effect, unless legal regulations more favourable to the concession holder are adopted. The commencement of operations is authorised separately.

The holder of a concession may be any Romanian or foreign legal entity. Foreign entities (including EU entities) must establish a subsidiary or branch office in Romania within 90 days of the concession coming into force and to maintain it for the entire duration of the concession. If there are joint concession holders, this obligation is incumbent upon the party designated to represent their interests.

An oil concession may be fully or partially transferred only with ANRM's prior written approval. The transferee should also be able to prove it has the necessary technical and financial capabilities, not have any debts towards the State budget, and undertake all outstanding obligations under the existing agreement.

The initial duration of a concession may be up to 30 years, which can then be extended once by a Government Decision for a further period of up to 15 years. The concession ends upon expiry, waiver by the concessionaire (provided certain cumulative conditions are met), rescission by the authority (for a concessionaire's failure to perform) or upon request from the concessionaire on the basis that an event of force majeure has arisen.

If a concessionaire is sanctioned for a breach, the authority may suspend the concession for up to a year. The suspension lasts for as long as the misdemeanour subsists. Failure by the concessionaire to remedy the misdemeanour entitles the authority to rescind the concession.

Two forms of royalty are payable by a concessionaire to the State:

- a percentage of the value of gross production on a field basis. The percentage is set based on production levels. The production royalty rate varies between 3.5% and 13% for crude oil and natural gas production; and
- a fixed rate of 10% of the concessionaire's gross income from the transportation and transit of oil through the national pipeline system and from oil operations carried out through oil terminals that are owned by the State.

In addition, under the new Offshore Law, offshore producers must pay a progressive windfall tax on additional revenues generated from the sale of offshore gas, ranging from to 15% to 70% depending on the gas price (ie the higher the sale price, the higher the percentage).

F. Renewable energy

F.1 Renewable energy

Romania reached the target of 24% of total renewable energy consumption in 2020. For 2030, the new target set by the Government in the Integrated National Energy and Climate Plan ("NECP") is 30.7%. Some 6GW of new wind power and solar photovoltaic ("PV") capacities must be installed over the next ten years to deliver on this target.

In terms of energy consumption, according to Eurostat data, in 2019, just over 24% of energy consumption came from renewable energy sources, placing Romania in tenth place in the EU and above the EU average.

In 2020, the generation of electricity in Romania came in proportion of 12.4% from wind energy, 3.4% from PV solar panels and 27.6% from hydropower. In total, the generation of renewable energy (wind, PV and biomass) accounted for 16% of the total.

Currently, there are 3,014.91MW installed in wind energy, 1,393.21MW in PV energy, 106.896 biomass and 6,644.43MW in hydro projects (including large hydro power plans in excess of 10MW).

Since 2005, Romania has used a combined system of mandatory quotas and green certificates ("GCs") to incentivise renewable energy deployment. This system was applicable to renewable energy projects commissioned into operation by end of 2016. The scheme has undergone numerous changes that substantially reduced the original support, leading to a steep decline in investor confidence.

F.2 Renewable pre-qualifications

There is currently no support scheme for new-built renewable energy projects, but Romania is working towards implementing a new scheme. A number of investors seem confident that renewables (in particular solar PV) have reached grid parity in Romania and are therefore ready to engage funds in the absence of a support scheme, expecting to rely on long-term, fixed-price PPAs or even take merchant power price risks. However, to increase investments in renewables on a larger scale, the Romanian market is still in need of a reliable support scheme.

In spring 2019, the Romanian Ministry of Energy announced the intention to implement a new mechanism for supporting low-carbon electricity generation in the form of a Contract-for-Difference ("CfD") scheme.

This intention was further formalised in June 2020, when the Government approved the key principles of the CfD scheme by way of a Memorandum, thus showing broad governmental support for this initiative. The proposed new scheme is inspired by the British CfD system, targeting both the renewables and the nuclear sector.

Overall, eligible generators enter into a private law contract (CfD contract) with the nominated counterparty and agree on a strike price. Generators sell electricity on the competitive market, via a route-to-market PPA or on the centralised power exchange. If the market price (reflected in the so-called reference price) falls below the strike price, the counterparty will reimburse generators the difference. Likewise, if the market price exceeds the strike price, the generators will reimburse the difference to the counterparty.

The Government expects that the CfD scheme will launch in 2023. As the implementation of the CfD scheme requires authorisation by the EU Commission, the credibility of the timeline advanced by the Government is questioned by the market.

F.3 Biofuel

The Renewable Energy Act sets a national target for at least 10% of the final national consumption of energy used in transport to come from renewable sources. To this end, Emergency Government Ordinance no. 80/2018 provides that from 1 January 2019 only diesel containing 6.5% and gasoline containing 8% of biofuel by volume can be sold on the market. Biofuels produced from waste and residues, other than residues from agriculture, aquaculture, fishing and forestry, may be put on the market if the defined sustainability criteria are met.

G. Climate change and sustainability

G.1 Climate change initiatives

The EU Climate Change Package has been largely implemented in Romania.

G.2 Emission trading

Romania was the first country to ratify the Kyoto Protocol, committing to reduce its greenhouse gas ("GHG") emissions by 8% compared to 1990 levels during the first trading period.

The main piece of legislation regulating trading in EU Emission Trading System ("EU ETS") allowances ("EUAs") is Government Decision no. 780/2006, supplemented by secondary legislation.

The Ministry of Environment and Climate Change oversees the implementation of EU legislation in this area and the National Environmental Agency (*Agentia Nationala pentru Protectia Mediului*) ("ANPM") is responsible for managing matters relating to EUA allocation and trading. ANPM is a subordinate body to the Ministry of Environment and Climate Change and is entirely financed by the State.

Installations that are subject to the obligations under the EU Emissions Trading Scheme ("EU ETS") must hold a GHG emissions authorisation issued by the National Environmental Agency, valid for the ten years trading period from 2021 to 2030.

The Romanian GHG Registry Regulation sets out the terms and conditions for accessing the online registry and setting up accounts. All operators must open an account with the National Register, which is an electronic, standardised and secure database that is open to the public. Private entities not subject to the obligations under the EU ETS can also open accounts allowing them to trade EUAs.

EUAs can be traded over-the-counter or via a broker, bank or an exchange.

Besides the EU ETS, no additional emission trading schemes operate in Romania.

G.3 Carbon pricing

Romania has not developed its own carbon pricing strategy.

G.4 Capacity markets

Romania has not implemented capacity markets mechanisms.

H. Energy transition

H.1 Overview

At a national level, Romania is slowly taking steps towards energy transitioning, as set out in the NECP for 2021 – 2030, which underlines the country's strategy in this field. The energy-related measures and policies need financial support of €22.6 billion. This is expected to be covered, among others, from various European funding sources (such as the Cohesion Policy, Just Transition Fund and Modernisation Fund), from international finance institutions, and from the state budget.

Romania has had a fully liberalised the electricity and gas market since 2021; a decisive step to supporting the development of new capacities and to ensure regional integration.

H.2 Renewable fuels

In the past couple of years, Romania has adopted various regulations regarding renewable hydrogen, before presenting a clear development strategy. Regulations are still in early stages and require further coordination and supplementation to effectively allow renewable hydrogen development and investments. Although, the Government has announced that a strategy and a reform of relevant legal framework shall be adopted to support and facilitate the development of renewable hydrogen.

Financial support for renewable hydrogen projects is expected to be available under the Romanian National Recovery and Resilience Plan and under the Modernisation Fund.

H.3 Carbon capture and storage

To implement the CCS Directive, MECBE has approved the 'National Programme for carbon capture and storage – 2020' as part of the Plan for Research-Development in Industry 2010. This programme ultimately aims to select a national project that could qualify for EU funding as a European carbon capture and storage ("CCS") demonstration project. Furthermore, in June 2011, the Government approved the Emergency Ordinance no. 64, which regulates the geological storage of CO_2 and transposes the CCS Directive into national law.

The Government has also announced the first CCS project to be undertaken in the country, for which ROMGAZ, TRANSGAZ, and Oltenia Energetic Complex (an electricity generator) formed a partnership. However, the project did not succeed to obtain funds from the NER 300 process managed by CE – DG Climate Action.

As part of the ConsenCUS research project in the field of carbon capture, use and storage technology ("CCUS") funded by the EU through the Horizon 2020 program, a pilot project is planned to be implemented at the Petrobrazi refinery of OMV Petrom.

Furthermore, the STRATEGY CCUS project promoting the development of technology CCUS, considers the city of Galati in Romania as area of interest for the project, giving the CO_2 storage options it offers and the proximity to the Black Sea.

H.4 Oil and gas platform electrification

There are no special obligations concerning the electrification of oil and gas platforms.

H.5 Industrial hubs

Industrial parks have been regulated in Romania for over 20 years. They are defined as specific perimeters were economic activities, research and development (R&D), industrial production and services are conducted, benefiting of specific facilities, with a view to capitalise on the human and material potential in the area.

Industrial parks are established with the acknowledgement of the Ministry of Development, Public Works and Administration. Industrial parks are not currently subject to clean energy obligations, but there have been several initiatives to set-up industrial parks using solely clean energy. Against the current energy price spikes and uncertainties, such initiatives are expected to materialise.

H.6 Smart cities

In its 2021 report, Vegacomp Consulting, the turn-key smart solution integrator, observed significant growth in smart initiatives in 124 cities around Romania.

This growth is triggered by various factors, such as the pandemic and the improved administrative response regarding remote solutions and limitation of bureaucracy. Furthermore, the implementation of smart solutions started to attract private funding, in addition to EU funding, which had been the primary financing source of smart solutions.

Alba Iulia remains the leader with highest number of smart projects, whereas Bucharest, the capital of the country, ranked fourth.

I. Environmental, social and governance (ESG)

Environmental, social and governance issues do not currently affect investment in energy in Romania.

Endnotes

1. As amended to date.
2. As set out in ANRE Order no. 12/2015 on the approval of the Regulation for granting licences and authorisations in the electricity sector, as published in the Official Gazette no. 180 of 17 March 2015.
3. See www.anre.ro/ro/despre-anre/rapoarte-anuale (report 2020, p.168).
4. By Government Emergency Ordinance no. 33/2007, the competences of ANRGN, the former regulatory authority for the gas sector (Autoritatea Nationala de Reglementare in Domeniul Gazelor Naturale), were transferred to ANRE from 18 May 2007.
5. Approved by ANRE Order no. 109/2013.

Energy law in Serbia

Recent developments in the Serbian energy market

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Unbundling in electricity sector

The unbundling of the distribution system operator from the vertically integrated company Javno preduzeće Elektroprivreda Srbija ("EPS") has been described as a "significant problem" of the Serbian energy market by the Energy community. The unbundling started with the transfer of EPS' shares in the distribution company "EPS Distribucija" to the Republic of Serbia. In January 2021, the Government established the new distribution company Elektrodistribucija Srbije. The company was licensed by the regulator on 1 April 2021. The share of EPS in the electricity market is about 97%, despite the fact that more than 70 suppliers are currently operating in Serbia. About 70% of electricity in Serbia is produced in EPS thermal power plants, while about 30% is obtained from 16 hydro power plants. Serbia has made significant progress in previous years in its accession process by transposing and putting into practice the Energy Community acquis and commitments to the European Union ("EU"). On the other hand, there is still room for improvement, for example, Serbia has not yet put the Inter Transmission System Operator ("TSO") Agreement it signed with Kosovo[1] back in 2014 into effect.

Unbundling in gas sector

In April 2021, the Government adopted an unbundling plan for Srbijagas and Yugorosgaz a.d. ("Yugorosgaz"), the lack of which amounts to longstanding breaches of Energy Community law[2]. The plan is not being implemented as promised. So far, only the transfer of ownership of the company Transportgas Srbija from Srbijagas to the Republic of Serbia has taken place in 2021. A pre-condition for unbundling of Yugorosgaz Transport d.o.o. (a company owned by Yugorosgaz) is the ratification of the intergovernmental Agreement between Russia and Serbia, which has not happened. Despite not being unbundled, Yugorosgaz Transport still continues to operate under a license issued by AERS[3]. In addition to these severe breaches of the Third Energy Package, Transportgas Srbija continues to deny access at the interconnection point Horgos[4], booking the capacities only for Srbijagas, Gazprom Export, and suppliers of Bosnia and Herzegovina. Despite Turk Stream (a gas pipeline completed in 2020 which is used as a replacement for the cancelled south stream gas pipeline) and its extension pipelines supplying gas to Serbia since January 2021, and to Bosnia and Herzegovina as of April 2021, the practice of denying access still exists. As a result, Srbijagas successfully blocks suppliers from central European hubs with greater liquidity from entering the Serbian market, and the pipeline is essentially empty.

New legislative developments in renewable energy

In April 2021, Serbia adopted its first renewable energy act, The Use of Renewable Energy Sources Act[5] ("RES Act"). This was a significant step forward in the adoption of the renewables agenda and should help scale up the production and capacities of renewable energy. Shifting from coal to renewable sources, and therefore the need for new hydro, wind, and solar generation plants, is a recognised goal in Serbian politics. In July 2021, the Serbian Ministry for energy and mining ("Ministry") proclaimed that the new energy strategy is under preparation, under which, up to 50% electricity would be generated from renewable sources by 2040. In November 2021, it was stated by Ministry that by 2040 or 2050 Serbia should have zero lignite consumption and that such shift would require minimum €17 billion investment.

During 2021, Serbia amended the Energy Law[6], which should enable the transposition of the Network Codes and the REMIT Regulation and facilitate access of low carbon and biogases in the grid. Nevertheless, the implementation of the Network Codes remains at a low level. Capacity allocation and congestion management procedures are not in place and the balancing rules are not aligned with the respective Network Code.

Adopting the RES Act and amending the Energy Act in the area of electricity and renewables made investments in the production of green energy easier, and their numbers are growing. At the same time, the imperative of decarbonization is pushing Serbian companies to look for new options for the energy supply, and their role will become more active in the coming years. It is now up to the companies to use the market's opportunities and adapt step by step to these changes. The priority for Serbia is the adoption of the necessary secondary legislation to enable implementation of the "RES Act".

For now, the following secondary legislation was adopted:

- Decree on criteria, conditions, and method of calculation of claims and obligations between prosumer and supplier[7];
- Decree on quotas for wind farms in the market premium system[8];
- Decree on market premium and feedin tariff[9];
- Decree on the model contract on market premium[10]; and
- Decree on the merger of organized dayahead and intraday electricity markets – ZOE[11].

Software for electronic auctions for acquiring rights to incentives for RES power plants was also developed.

The most important act of secondary legislation was adopted in November 2021, when Serbia adopted the Decree on market premiums and feedin tariffs. This legislation prescribes that incentives for the production of electricity from renewable sources are carried out in a specific incentive period through the system of market premiums and the system of feedin tariffs and refer to the price of electricity, and acquiring balance responsibilities. Market premiums are a type of operational state aid that represents an addition to the market price of electricity that users of the market premium delivered to the market, and which is determined in Eurocents per kWh in the process auction. A market premium can be acquired for all or part of the capacity power plants and is paid on a monthly basis for electricity that was delivered by the power plant to the power system. The Government, at the proposal of the Ministry, regulates the type, method, and conditions of acquisition, realisation, and termination of the right to the market premium, as well as the method determining the reference market price. For the purposes of auctions, the Serbian Energy Agency ("AERS") determines the maximum market premium or maximum purchase price for electricity per kWh. Methodology for determining the maximum market premium or the height maximum purchase prices is also prescribed by AERS.

The right to market premiums is acquired in the auction procedure. The Ministry conducts auctions based on the available quotas which are prescribed by the Government. Qualification is the elimination phase of the auction procedure in which a selection is carried out of registered participants based on the fulfilment of the following conditions:

- types and approved power of the power plant;
- the planning basis for the construction of the connection of the power plant to electro energy system; and
- if the auction participant acquired:
  - legally valid energy permit for the power plant;
  - locational conditions (technical planning conditions); and
  - a financial security instrument for the seriousness of the offer.

Electricity and gas participants in numbers

According to AERS there are 34 electric energy producers, 64 Electricity supply operators, and 62 natural gas suppliers operating in the Serbian energy market[12]. However, it must be noted that the market has monopolistic features because of the dominance of stateowned companies such as EPS and Srbijagas. Under the Energy Act, all final customers except households and small customers must choose their electricity supplier at unregulated prices. The right to be supplied under regulated prices is reserved only for households and small customers, who may opt to be supplied by a guaranteed supplier.

Power generation

Generation from hydropower plants amounts to about 30% of the total electricity generated in Serbia, while generation from thermal power plants ("TPPs") amounts to about 64%. In 2021, power plants in Serbia had generated electricity in the total amount of 34,028 Gwh, of which 66% was produced by TPPs, 30% by hydropower plants, 0.8% by thermoheating power plants, 1.2% by other small power plants and 2.4% by wind farms which is significant increase from 0.15 back in 2017.

Serbia is still obliged to shut down a significant part of its thermal capacities pursuant to the Large Combustion Plants[13]. The deadline for this has been extended from 2017 to 2023 by the Ministerial Council of the Energy Community. Serbia must shut down all power blocks of less than 300MW that are not subject to the projects of mitigation of emissions of hazardous substances. The total capacity of generation to be closed by 2023 amounts to about 1,100MW. Serbia remained far from reaching its target of 27% of renewable energy in gross final energy consumption in 2019. Not only is the share of renewables well below the 2020 renewables target, but it is also lower than the renewables share set in the baseline year 2009 due to growing energy consumption. Serbia is lagging in all three sectors: electricity, heating and cooling and transport.

New projects

In November 2020, the governments of Serbia and the Bosnia and Herzegovina entity of Republic of Srpska announced the construction of three hydropower plants on the Drina estimated at €520 million. In January 2021, Balkan Stream (an extension of Gazprom's Turkish Stream pipeline that runs via Southeast Europe to Hungary, that bypasses Ukraine) gas pipeline opened through Serbia. On the territory of the city of Pancevo, 8 wind power plants are currently being developed with a total planned installed capacity of more than 1GW. Serbia could get five new interconnections for the transmission of electricity with Bosnia and Herzegovina, Bulgaria, Croatia, Hungary, Montenegro, and Romania. It is estimated that this interconnection should be finished by 2035.

The new power lines will increase northsouth and eastwest transmission capacities via Serbia and boost energy exchange with neighbours, as well as strengthening the country's security of supply and limiting the reliance on Russia.

Greece and Bulgaria have started commercially operating a longdelayed gas pipeline, which will help decrease southeast Europe's dependence on Russian gas and boost energy security. The 182 kilometre pipeline will provide a relief to Bulgaria, which has been struggling to secure gas supplies at affordable prices since the end of April, when Russia's Gazprom cut off deliveries over Sofia's refusal to pay in roubles. The Interconnector Greece-Bulgaria pipeline will transport 1 billion cubic metres (bcm) of gas from Azerbaijan to Bulgaria. With an initial capacity of 3bcm per year and plans to later raise this to 5bcm, the pipeline could provide non-Russian gas to neighbouring Serbia, North Macedonia, Romania, and further to Moldova and Ukraine. At the beginning of this year, with the support of the EU, Serbia started the construction of a 109km long gas interconnector with Bulgaria, Niš, and Dimitrovgrad, on the territory of Serbia, and the works should be completed by September 2023. With that gas pipeline, Serbia will be connected to the gas pipeline between Bulgaria and Greece, that is, it will be able to supply gas from Azerbaijan or from the Alexandroupolis LNG terminal in Greece.

New legislative authority for AERS

The Energy Agency of the Republic of Serbia (AERS) received new authority as a result of amendments to the Energy Act. In order to implement gas and electricity Network Codes into the national grid codes, the regulator used its newly acquired authority to issue guidance to national transmission companies. On the Ministry's recommendation, the Government of Serbia is yet to formally accept them in order to implement the gas and electricity Network Codes. The regulator's operational capacity to meet deadlines is demonstrated by the acceptance of methodology on prosumers and storage, the granting of new licenses, and the beginning of public consultations on cogeneration. Additionally, REMIT's transposition has been finalised.

Meanwhile, there has been little progress in the certification of network operators, the regulation of unbundling, or third-party gas access. AERS supports household prices that are regulated and below market rates. This Third Energy Package lethargy and contempt for important criteria are a cause of concern and contrast with the high degree of subject matter expertise seen in AERS. In the future we should also expect Serbia to speed up its Carbon taxation regulation in order to prevent taxation for exports to the EU, because that would pose a significant cost considering about 70% of Serbian exports go to EU countries.

Climate change

The Climate Change Act[14] was adopted in March 2021. It prescribes the adoption of the Low Carbon Development Strategy with an Action Plan within two years from the adoption of the Act. Also, it sets the basis for the establishment of a national system for policies, measures, and projections, which will be operational upon adoption of the relevant bylaws (planned for March 2022). The Climate Change Act stipulates that the Serbian Environmental Protection Agency establishes and maintains the GHG inventory and prepares the inventory report. A set of bylaws, currently being drafted, lists the types of data and the bodies and competent authorities requested to submit data on GHG emissions to the Agency, which will ensure data quality control. Serbia complied with its reporting obligations under the Large Combustion Plants Directive for 2020 and provided emission scenarios considering ongoing investments. In 2020, the emission of all three pollutants slightly increased, while a slight decrease in dust emissions was recorded for plants under the NERP.

Endnotes

1. Kosovo is a territory disputed between Serbia and the self-proclaimed Republic of Kosovo, who has de-facto control. Koso-vo's independence is recognised by 110 UN member states.
2. By adopting the Energy Community Treaty, the Contracting Parties made legally binding commitments to adopt core EU energy legislation, the so-called "acquis communautaire".
3. The Energy Agency of the Republic of Serbia.
4. A village in northern Serbia near the Serbo-Hungarian border.
5. Official Gazette of RS No. 40/2021-23.
6. Official Gazette of RS No. 145/2014.
7. Official Gazette of RS No. 83/2021-3, 74/2022-3.
8. Official Gazette of RS No.40/2021.
9. Official Gazette of RS 55/05, 71/05.
10. Official Gazette of RS. 112/2021.
11. Official Gazette of RS. 10/2022-11.
12. See www.aers.rs/Index.asp?l=1&a=535.3&sid=1&tp=Zanpra.
13. Directive Directive 2001/80/EC of 23 October 2001 on the limitation of emissions of certain pollutants into the air from large combustion plants.
14. Official Gazette of RS No. 26/2021.

Overview of the legal and regulatory framework in Serbia

A. Electricity

A.1 Industry structure

Nature of the market

Serbia's electricity production mostly relies on coal and, to a lesser extent, hydropower. Roughly, 70% of electricity in Serbia is produced in thermal power plants, while about 30% is obtained from hydroelectric power plants.

The electricity market in Serbia is open and largely liberalised due to the creation of an energy exchange, as well as bilateral and balancing energy markets. On the other hand, unbundling of the transmission system operator still requires legislative changes.

Key market players

The key market players in the Serbian Electricity market are:

- Javno preduzeće Elektroprivreda Srbija ("EPS") responsible for almost the entire production of electricity in Serbia;
- Elektrodistribucija Srbije a stateowned subsidiary of EPS that carries out the distribution of the electricity. The actual activity of electricity distribution is carried out by its branches; and
- Elektro Mreža Srbije a.d ("EMS"), state owned operator of the electricity transmission system.

The dominance of the EPS and its subsidiaries and regulated low prices continue to impede the development of competition in the retail market and supplier switching.

Regulatory authorities

The Regulatory powers in the Serbian electricity market belong to:

- The Government of the Republic of Serbia ("Government"), which, together with the Serbian Parliament, is the main regulator of the energy sector in the Republic of Serbia;
- The Ministry of Mining and Energy of the Republic of Serbia ("Ministry"), which is the government entity in charge of various regulatory functions, adopting certain legislative acts pursuant to the Energy Act and implementing laws within its competences as well as supervisory functions; and
- The Energy Agency ("AERS"), an independent regulatory body, is in charge of issuing and revoking energy licences, adopting methodologies for setting up prices in the electricity and natural gas market, approving regulated prices, giving approval to the operating guidelines of various energy sector systems, and monitoring the energy market.

Legal framework

The Serbian electricity sector is governed both by local legal acts and international treaties ratified by Serbia. The focal stone of the legislation is the Energy Act[1], which sets the core principles and rules pertaining to the entire energy sector in Serbia. The Energy Act also transposed the Third Energy Package of the European Union ("EU"). The basic rules set in the Energy Act are further regulated in more detail by secondary legislation, which sets requirements and rules for implementation of the Energy Act's provisions regulating, among others, the electricity sector. Such secondary legislation is listed below:

- Energy Act (*Zakon o energetici*);
- Electricity Market Code (*Pravila o radu tržišta električne energije*)[2];
- Use of Renewable Energy Sources Act (*Zakon o obnovljivim izvorima energije*)[3];
- Decision on Amounts of Costs for Issuance of Licence to Perform Energy Activity; (*Odluka o visini troškova za izdavanje licence za obavljanje energetskih delatnosti,*)[4];
- Rulebook on Licence for Performing Energy Activity and Certification (*Pravilnik o licenci za obavljanje energetske delatnosti i sertifikaciji*)[5];
- Decision on Determining the Reserve Supplier of Electricity (*Rešenje o određivanju snabdevača koji će obavljati rezervno snabdevanje električnom energijom*)[6];
- Decree on Incentive Measures for Privileged Power Producers (*Uredba o merama podsticaja za povlašćene proizvođače električne energije*)[7];
- Decree on Incentive Measures for Generation of Electricity from Renewable Sources and from High-Efficiency Combined Heat and Power ("CHP") Generation (*Uredba o podsticajnim merama za proizvodnju električne energije iz obnovljivih izvora i iz visokoefikasne kombinovane proizvodnje električne i toplotne energije*)[8];
- Decree on Power Purchase Agreements (*Uredba o ugovoru o otkupu električne energije*)[9];
- Decree on Guarantees of Origin (*Uredba o garanciji porekla*)[10];
- Decree on Criteria, Conditions and Method of Calculation of Claims and Obligations between Prosumer and Supplier (*Uredba o kriterijumima, uslovima I načinu obračuna potraživanja I obaveza između kupca – proizvođača I snabdevača*)[11];
- Decree on Quotas for Wind Power Plants in Market Premium System (*Uredba o kvotama I sistemu tržišne premije za vetroelektrane*)[12];
- Decree on Market Premiums and Feedin Tariff (*Uredba o tržišnoj premiji I fidin tarifi*)[13]; and
- Decree on Model Contract on Market Premiums (*Uredba o modelu ugovora o tržišnoj premiji*)[14].

The extent of implementation of the EU electricity directives

Serbia is an active member of the Energy Community and one of the signatories to the relevant Energy Community Treaty ("EC Treaty") since 2005[15]. As a signatory to the EC Treaty, Serbia has undertaken to implement the core principles of the EC acquis Communautaire, both sector specific and general, as well as to bring its entire energy sector in line with relevant Energy Community's standards. The EU third energy package was transposed into Serbian legislature by the Energy Act. One of the most important features of the Package is the unbundling regime, ie, the separation of the transmission level from the business of production or distribution of electricity. The unbundling of the distribution system operator from the vertically integrated company EPS began when EPS transferred its shares in the distribution company EPS Distribucija to the Republic of Serbia. Current distribution system operator ("DSO"), Elektrodistribucija Srbije, was established by the Government in January 2021 as a new distribution company, later licensed by the AERS on 1 April 2021. However, regarding the unbundling of the transmission, transmission system operator ("TSO") has not been unbundled in line with the Third Energy Package. The decision making rights for the EMS and for other public enterprises responsible for production and supply of electricity remain with the Government. Nevertheless, there are signs of legislative efforts to change that eg, REMIT Regulation has been transposed.

A.2 Third party access regime

Access to the relevant grid (transmission or distribution system), is obtained on the basis of an access agreement concluded between the system operator (EMS as the TSO or Elektrodistribucija Srbije as the DSO) and the grid user, in accordance with the Energy Act and the relevant grid code. Third parties must be allowed to access the transmission or distribution system in accordance with the principles of transparency and nondiscrimination. In addition to the elements specified by the law governing contractual relations (Contract and Tort Act ("CTA"))[16], the grid access contract must contain the following:

- information on the delivery point of electricity;
- information on the power and capacity at the delivery point; and
- information on the billing period and the method for calculating the consumption of electricity, as well as other elements depending on the particularities of the delivery point.

A.3 Market design

By the adoption of the Energy Act, the national legislation encompassing the energy sector is largely harmonised with the provisions of the Third Energy Package of the EU. The adoption continued the process of introducing competition in the electricity sector in Serbia in order to increase the efficiency of the sector through the market mechanisms in generation and electricity supply, while maintaining economic regulation activities of transmission and distribution of electricity and natural monopolies.

When trading in the market, the buyer and the seller enter into agreement regarding some of the most important elements of the trade, such as the quantity and quality of the goods, the time and place of delivery, and the method of payment, etc. The development of the market in Serbia took place through three phases. The first one is related to consumers connected to high voltage, the second phase regulated the position of consumers connected to medium voltage, while the third phase regulated the position of consumers connected to low voltage. The main types of electric energy markets in the Republic of Serbia are:

- Bilateral;
- Balanced; and
- Organised market for electricity.

Participants in the electricity market in Serbia, according to the Energy Act, can be electricity producers, suppliers and wholesale suppliers, end customers, transmission, distribution and closed distribution system operators, and other legal entities in accordance with the rules on the operation of the organized market.

In Serbia a dayahead market operated by SEEPEX, Serbian power exchange, exists, whereas an intraday electricity market still remains to be established. There is a possibility of the introduction of the coupling of electricity markets which other countries have introduced.

A.4 Tarrif design

AERS is the key factor regarding the charging methodology for access/use of the grids (distribution and transmission). In that respect AERS provides (among others) methodologies for determining:

- costs of access to the electricity transmission system:
- costs of access to the electricity distribution system;
- electricity prices for public supply; and
- costs of connection to the system for transmission and distribution of electricity.

AERS analyses and reviews the need for regulated prices (eg prices for access to the transmission and distribution grids) on a yearly basis, taking into account the achieved level of competition at the local electricity market, achieved level of protection of vulnerable customers, development of the regional electricity market, and assessment of available crossborder capacities.

Tariffs are adopted by the relevant operators, in line with applicable methodology adopted by AERS, and are approved by AERS expost as a precondition for their entry into force.

A.5 Market entry

According to the Energy Act, wholesale electricity supply is defined as the activity of selling electricity to customers, including resale, but does not include selling to endcustomers. Selling to end customers is known as "Wholesale Activity" andis a category of energy activity that is subject to an AERS issued license for performing energy activity. Therefore, for one to conduct electricity Wholesale Activity, one must obtain from AERS a licence for performing the energy activity of wholesale electricity supply (“Wholesale Licence”). A foreign, non-Serbian legal entity can obtain a wholesale license, which may be granted to a legal entity (a partnership, limited partnership, limited liability company, or jointstock company) incorporated in Serbia or to an entrepreneur registered in Serbia. These Legal Entities formed and registered in Serbia are known as “Local Corporations”.

For the electricity sector, a licence is required for, among others, the following activities:

- Generation of electricity (in energy facilities with an approved capacity above 1MW and where the same energy company generates electricity in two or more energy facilities that have combined power of above 1MW, regardless of whether such facilities are connected to the grid through one or more grid connections);
- CHP power generation (in energy facilities having the approved capacity of above 1MW);
- transmission of electricity and operation of the transmission system;
- distribution of electricity and operating a closed distribution system;
- supply of electricity;
- wholesale supply of electricity; and
- operation of the organised electricity market.

An electricity Wholesale Licence is issued for a period of ten years and may be renewed upon request by the licensee. The renewal request must be filed with AERS thirty days prior to the Wholesale Licence expiration date at the latest. An electricity Wholesale Licence cannot be transferred.

The Serbian Energy Act, and more specifically the Licensing Rulebook[17] ("Rulebook"), primarily outline the requirements and conditions for obtaining an Electricity Wholesale Licence.

According to the Rulebook and information obtained from AERS, the documents that must be submitted to AERS, alongside an application for the issuance of a Wholesale Licence, are as follows:

If the applicant is a local corporation:

- Excerpt from the Commercial Register of the Agency for Commercial Registers for the Local Corporation;
- Certified copy of the Local Corporation's foundation act;
- Decision of relevant authority on settlement of tax duties by the Local Corporation;
- Business plan for the year in which the Local Corporation applies for the licence;
- Certificate by a bank regarding all transactions and daily balances on all active bank accounts of the Local Corporation applying for the Wholesale Licence, for the previous two years; the Local Corporation's balance sheet and income statement for the previous two years or if the Local Corporation was not operational for two years previously, a certificate by a bank regarding all transactions and daily balances on all active bank accounts as of the date of opening the account until the date of filing the request with the bank; the balance sheet and income statement of the Local Corporation for the previous year;
- Proof by the competent authority that the members of the management bodies of the Local Corporation have not been sentenced for any criminal acts related to the performance of the business activity;
- Proof by the competent authority that the Local Corporation has not been banned from performing its activities or that the legal effects of any such ban have elapsed;
- Proof by the competent court that no bankruptcy proceedings have been initiated over the Local Corporation;
- Certificate by the Agency for Commercial Registers that no liquidation proceedings have been initiated over the Local Corporation;
- Proof of payment of the administrative fee and fee for issuance of licence.

If the applicant is a foreign legal entity:

- Excerpt from the relevant commercial register for the foreign legal entity;
- Decision of the relevant authority on the settlement of tax duties by the foreign legal entity;
- Business plan for the year in which the foreign legal entity applied for the licence;
- Certificate by a bank regarding all transactions and daily balances on all active bank accounts of the foreign legal entity applying for the Wholesale Licence, for the previous two years, the foreign legal entity's balance sheet and income statement for the previous two years, or if the foreign legal entity was not operational for two years previously, a certificate by a bank regarding all transactions and daily balances on all active bank accounts as of the date of opening the account until the date of filing the request with the bank; the balance sheet and income statement of the foreign legal entity for the previous year, and a certificate from the bank or mother company that it can provide the necessary financial funds or other security instruments for the planned volume of activities of the foreign legal entity applying for the Wholesale Licence;
- Proof by the competent authority that the members of the management bodies of the foreign legal entity applying for the Wholesale Licence have not been sentenced for any criminal acts related to the performance of the business activity;
- Proof by the competent authority that the foreign legal entity has not been banned from performing its activities or that the legal effects of any such ban have elapsed;
- Proof by the competent authority that no liquidation or bankruptcy proceedings have been initiated over the foreign legal entity;
- Licence for performing activity of electricity supply issued in another country, or a document of the competent authority stating that the foreign legal entity is a participant on an electricity market or power exchange in the European Union or in the countries signatories of the Treaty establishing the Energy Community; and
- Proof of payment of the administrative fee and fee for issuance of licence.

A.6 Cross-border interconnectors

Cross-border capacity on the interconnections with Croatia and Bulgaria are allocated through the Joint Auction Office. On other interconnectors, joint auctions still apply, except with Albania where split allocations are implemented. The agreement on grid control cooperation in the control block of Serbia, Montenegro, and North Macedonia is expected to commence with imbalance netting between Serbia and Montenegro in the first phase.

Cross-border trading is performed through the cross-border transmission system. Access to the cross-border transmission system is based on the right of use of the system, which is exercised by means of an agreement concluded between the TSO and the market participants. Cross-border capacities are assigned to users in a nondiscriminatory and transparent manner. In order to participate in the process of allocation of cross-border capacities and use the cross-border capacities, an eligible market participant engaged in electricity trade activities must:

- have a valid licence for carrying out the relevant energy activity in accordance with the applicable law;
- have an EIC identification code (which is issued by EMS in Serbia); and
- fulfil obligations as stated under the Rules for allocation of relevant cross-border transfer capacities on the relevant border to the territory of Serbia and depending on the type of auction. Afterwards, a participant must conclude the necessary agreement with the relevant TSO in order to become a registered participant in allocation and procedure and to engage in the respective allocation procedure.

Serbia has several cross-border interconnectors including:

- Bulgaria: 440kV;
- Hungary: 440kV;
- Macedonia: one of 440kV and two of up to 220kV;
- Montenegro: one of 440kV and two of 220kV;
- Albania: up to 220kV;
- Bosnia and Herzegovina: one of 440kV and one of up to 220kV;
- Croatia: 440kV;
- Romania: 440kV; and
- Croatia: 440kV.

According to Serbia's TSO, EMS, the implementation of all five projects is expected before 2035.

A.7 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

In accordance with the Serbian Energy Act, an energy entity that has a licence to perform energy activities may be required to provide a public service that will ensure security of supply, regularity, quality and price of supply, environmental protection, including energy efficiency, use of energy from renewable sources and climate protection. Obligations to provide public services must be clearly defined, transparent, nondiscriminatory, verifiable, timelimited, must guarantee the equality of energy entities in the provision of public services and cannot influence the opening of the market.

The Energy Act also recognises guaranteed supply of electricity as the public service obligation. The guaranteed supply is available to vulnerable customers, households, and small consumers, under regulated prices, upon their request or automatically, if these customers do not select another supplier. The guaranteed supply is performed by EPS, as a public supplier and a guaranteed supplier appointed in the Energy Act itself.

Smart metering

The operator of the transmission system, transport system, or distribution system determines the technical requirements for the introduction of various forms of advanced measurement systems and analyses the technical and economic justification of the introduction of advanced measurement systems, and the effects on market development.

In September 2021, EPS signed a loan agreement for the smart metering rollout with the European Bank for Reconstruction and Development (EBRD). The entire project in Serbia is valued at € 80 million, and the agreement with the EBRD covers the first phase – the procurement and installation of software and the new system, and the replacement of about 205,000 smart meters in the cities of Kraljevo, Čačak, and Niš.

Electric vehicles

Energy Act only mentions Electric Vehicles once (*Article 210*), the reason being that the Serbian electric car market is not developed enough. However, the use of electric vehicles is increasing over the past period and the authorities seem to acknowledge the trend and support their use through the increase of charging stations throughout the country. Currently, there are around 40 installed charging stations in the cities and around 20 on the Serbian highways.

B. Gas and oil

B.1 Industry structure

Nature of the market

Serbia has produced oil and gas in small quantities since the mid 50s,but is heavily reliant on imports. Serbia and Bulgaria are connected by the so called TurkStream 2 project, a natural gas pipeline from Russia to Turkey and then Bulgaria that began delivering gas from Russia in early 2020. There is no TSO in Serbia unbundled in line with the Third Energy Package. The market is dominated by the stateowned JP Srbijagas ("Srbijagas"). Until a competitive natural gas market is established in Serbia, the Government will, in a public tender procedure, designate the supplier that will supply public suppliers of natural gas, at their request and the same price being applicable to all public suppliers. As for the Serbian oil market it is a bit more diversified but still dominated by a strong entity jointly owned by the Republic of Serbia and Gazprom Neft.

Regulatory authorities

The Regulatory powers in the Serbian oil and gas market belong to the Government, Ministry, and AERS.

Participants in the natural gas market in Serbia are: producers, suppliers, public suppliers, end customers, operators of transport systems, operators of distribution systems, and storage operators.

Key market players

The key market players in Serbia's gas market include the stateowned company Srbijagas (owner of the grid), and a vertically integrated joint stock company Yugorosgaz a.d. ("Yugorosgaz") (which is owned by Gazprom (50%), Srbijagas (25%), and Central ME Energy & Gas GmbH, Vienna (25%)). The right to freely choose a supplier in the market is guaranteed to all customers as of 1 January 2015.

Within the transport system, there are two operators of natural gas transport networks that are listed as of October 2022. These can be found in the Registry of LicenceHolders on the AERS website: YugorosgazTransport d.o.o. (a company owned by Yugorosgaz), and Gastrans d.o.o. Novi Sad.

According to the Registry of LicenceHolders available on the Web site of AERS, as of August 2022 there are 38 companies that are holders of a licence for natural gas distribution and the management of a natural gas distribution system. Although some of these licence holders are privately owned, most are public companies. According to the Energy Act, each operator of a natural gas distribution system is required, among other things, to create a Natural Gas Distribution System Code (The Natural Gas Distribution System Code sets out the minimum standards for the operation and use of the gas system). This code must be adopted after receiving AERS' approval, and each operator must publish it on both their own website and AERS website. Transportgas continues to deny access at the interconnection point Horgos, booking the capacities only for Srbijagas, Gazprom Export, and suppliers of Bosnia and Herzegovina. By doing so, Srbijagas effectively prevents suppliers from more liquid central European hubs from entering the Serbian market, and thus, the pipeline is virtually empty. Company PSG Banatski Dvor doo Novi Sad ("Banatski Dvor"), owned by Srbijagas and the limited liability company Gazprom Eksport from Russia, is the only licence holder for natural gas storage and for the management and operation of natural gas storage as of August 2022. As of 1 January 2015, all end customers including households and small buyers are entitled to freely choose their supplier of natural gas, whereby households and small buyers retained the right to public supply.

Legal framework

The main piece of legislation in the Serbian gas sector is the Energy Act, which regulates the requirements for performing activities of gas transport, distribution, supply and storage, licencing requirements, certification procedures of the system operators, thirdparty access regime, unbundling principles and other key principles governing the gas sector in Serbia. Each of the gas activities are further regulated by the codes adopted by the system operators and approved by AERS.

Exploration, extraction of natural gas, production, processing and refining of oil, as well as construction of mining facilities and mining works, are governed by Energy Act and the Mining and Geological Exploration Act ("MGEA")[18]. MGEA's secondary legislation also governs specific areas of exploration and extraction of natural gas. Gas is considered a mineral resource of strategic importance for Serbia under the MGEA, which, inter alia, ensures expropriation possibility.

Transportation of natural gas is further regulated, in addition to basic principles prescribed under the Energy Act and MGEA, under the special Act on Pipeline Transportation of Gaseous and Liquid Hydrocarbons and Distribution of Gaseous Hydrocarbons[19] and other relevant gas and oil related regulations.

Implementation of EU gas directives

In April 2021, the Government adopted an unbundling plan for Srbijagas and Yugorosgaz, the lack of which amounts to longstanding breaches of Energy Community obligations. However, the plan is not being implemented as stipulated. So far, only the transfer of ownership of the company Transportgas Srbija ("Transportgas") from Srbijagas to the Republic of Serbia has taken place in June 2021.

Therefore, there is a wide gap between transposition and implementation of the Energy Community commitments.

Licensing regime

As for the licensing regime, natural gas Wholesale Activity falls under the definition of "supply of natural gas" as defined by the Energy Act. Natural gas supply is defined as the activity of selling natural gas to clients for their personal purposes or with the intention of reselling it. This activity is only permitted by those who have a license from AERS to carry out the energy activity of supplying natural gas. Although it is not stated in the legislation explicitly, holders of a license for the supply of natural gas have access to storage and transportation networks and are permitted to engage in the import and export of natural gas, according to practice and information collected from AERS. Thus, to engage in natural gas Wholesale Activity, one must obtain from AERS a licence for performing the energy activity of natural gas supply ("Wholesale Licence"). A natural gas Wholesale Licence is issued for a period of ten years and may be extended upon request by the licensee (for more detailed analysis see section B.5).

The Government prescribes the method of determining the highest prices of basic oil derivatives without fiscal duties to prevent disruptions in the oil market and oil derivatives, This also ensures the removal of harmful consequences of disruptions in the market of oil and oil derivatives.

B.2 Third party access regime to gas transportation networks

The Energy Act transposes nondiscriminatory network access to the transmission and distribution system and storage facilities, as well as to upstream pipelines, as a principal rule. Access to the natural gas transport system is based on the right to use the transport capacity at the entrances and exits of the transport system. The right to use the transport capacity is realized based on an agreement on the transport of natural gas concluded by the TSO's (Srbijagas or Yugorosgaz) with the market participants, in accordance with the rules prescribed in network codes of Srbijagas and Yugorosgaz.

AERS approves network tariffs based on its methodologies defined and published in advance. The Transmission Tariff Methodology[20] is based on entry/exit principles. Access to storage in Serbia is regulated via a Storage Tariff Methodology[21] adopted by AERS.

An energy entity that carries out the activity of transporting oil through pipelines or transporting oil derivatives through product pipelines is obliged to enable users of the system to access the system for transporting oil or products through pipelines at regulated prices based on the principle of publicity and nondiscrimination, in accordance with the provisions of the Energy Act.

B.3 LNG terminals and storage facilities

The operator of natural gas storage must assign the right to use the natural gas storage capacities in a transparent and nondiscriminatory manner. The storage capacity may be assigned on a longterm basis, that is, for a period of one or more years, or on a shortterm basis, for a period shorter than one year, and the capacity may be assigned as firm or interruptible.

Regarding the LNG Terminals, in 2022, works on Alexandroupolis LNG terminal started. This LNG terminal is a significant project for the energy security of Southeastern Europe and Balkans. The Alexandroupolis FSRU is a floating LNG terminal that will provide 5.5 billion cubic meters (bcm) of natural gas annually when completed. This will be provided to the markets of Greece, Bulgaria, Serbia, and North Macedonia. The terminal is expected to be operational no later than December 2023.

B.4 Tariff regulation

The third-party access to the oil transmission grid, operated by Transnafta, is subject to the same principles of transparency and nondiscrimination. Access to the system for transporting oil through pipelines or the system for transporting oil derivatives through product pipelines is regulated by an access agreement concluded by the energy entity Transnafta that performs the activity in accordance with the system's operating rules. The accession agreement contains: data on the place of receipt and place of delivery, transport dynamics, quality of oil, ie oil derivatives, penalties for illegal deviations in the quality and quantities of unsold or undelivered oil or oil derivatives, ie deviations from the agreed transport dynamics, as well as other elements depending on the specifics of the place of receipt and the place of delivery.

Transnafta may reject the third party access due to the following reasons: (i) operational disturbances or if the system is overloaded; (ii) endangered security of the system; (iii) inappropriate quality of the oil and oil derivatives of the third party seeking access; and (iv) other reasons determined in Transnafta's grid code (the code does not provide any specific grounds for rejection, and it is based on the nondiscriminatory principle as well).

Under Serbian law, natural gas transport is an activity of public interest. The access tariff, ie entry exit tariff, is determined by the TSO, based on the methodology rendered by AERS. The same applies for access to the oil transportation system, ie, the final tariff is established by the TSO Transnafta in accordance with the AERS methodology. Such adopted tariffs are approved expost by AERS.

Other terms may be regulated by the access agreement between the relevant TSO and the party seeking the connection, provided that they comply with the principles under the grid codes, Energy Act or other applicable decisions of AERS.

The most important legal acts governing tariff regulation are adopted by AERS and include the following:

- the methodology for determining the price for access to transport oil pipelines and oil derivatives[22] (*Metodologija za određivanje cene pristupa sistemu za transport nafte naftovodima i derivata nafte produktovodima*);
- the methodology for determining the price for access to the natural gas transportation[23] (*Metodologija za određivanje cene pristupa sistemu za transport prirodnog gasa*);
- the methodology for determining the costs of natural gas for public supply (*Metodologija za određivanje cene prirodnog gasa za javno snabdevanje*)[24];
- the methodology for determining the costs of connecting to the system for the transportation and distribution of natural gas (*Metodologija za određivanje troškova priključenja na sistem za transport i distribuciju prirodnog gasa*)[25];
- the methodology for determining the costs of connecting to the system for the transportation of oil (*Metodologija za određivanje cene pristupa sistemu za transport nafte naftovodima I derivate nafte produktovodima*)[26]; and
- the rules on change of supplier (*Pravila o promeni snabdevača*)[27].

B.5 Market entry

To engage in natural gas Wholesale Activity, one must obtain from AERS a licence for performing the energy activity of natural gas supply ("Wholesale Licence"). In any case, the Wholesale Licence cannot be obtained by a foreign (non Serbian entity), it may only be issued to a legal entity incorporated in Serbia or to an entrepreneur registered in Serbia. This legal entity incorporated in Serbia is referred to as a "Local Corporation". A Local Corporation can be established in Serbia by a foreign company. Under the Serbian Companies Act[28], a Local Corporation can be established by one or more domestic or foreign legal entities or natural persons, or a combination thereof.

A natural gas Wholesale Licence is issued for a period of ten years and may be extended upon request by the licensee. The extension request must be filed with AERS, at the latest, 30 days prior to the Wholesale Licence expiration date. A natural gas Wholesale Licence cannot be transferred.

Conditions for obtaining a natural gas wholesale license are generally stipulated in the Energy Act, especially in the rulebook. According to the rulebook and AERS' practice, the documents that must be submitted to AERS together with the application for the issuance of a natural gas Wholesale Licence are as follows:

- Excerpt from the Commercial Register of the Agency for Commercial Registers for the Local Corporation;
- Certified Copy of the Local Corporation's foundation act;
- Decision of the relevant authority on the settlement of tax duties by the Local Corporation;
- Business plan for the year in which the Local Corporation applies for the licence;
- Certificate by a bank regarding all transactions and daily balances on all active bank accounts of the Local Corporation applying for the Wholesale Licence, for the previous 2 (two) years; the Local Corporation's balance sheet and income statement for the previous two years (this document should be prepared by a Serbian accounting firm in accordance with the Accounting Law of the Republic of Serbia) and the standardised BON-1 and BON-2 solvency reports, or if the Local Corporation was not operational for two years previously, a certificate by a bank regarding all transactions and daily balances on all active bank accounts as of the date of opening the account until the date of filing the request with the bank; the balance sheet and income statement of the Local Corporation for the previous year, ie the initial balance sheet, and a certificate of the bank or mother company that it can provide the necessary financial funds or other security instruments for the planned volume of activities of the applicant, ie the Local Corporation;

- Proof by the competent authority that the members of the management bodies of the Local Corporation (which in the case of a onetier limited liability company is the Managing Director(s), and in the case of a twotier limited liability company are the Managing Director(s) and the Supervisory Board) have not been sentenced for any criminal acts to perform activities, and that the Local Corporation was not banned under the Law on Misdemeanours to perform activities;
- Proof by the competent authority that the Local Corporation has not been banned from performing its activities or that the legal effects of any such ban have elapsed, namely certificates issued by relevant courts confirming that the Local Corporation has not been banned from performing its activities, that the Local Corporation was not banned under the Law on liability of legal entities for criminal acts;
- Proof by the competent court that no bankruptcy proceedings have been initiated over the Local Corporation;
- Certificate by the Agency for Commercial Registers that no liquidation proceedings have been initiated over the Local Corporation; and
- Proof of payment of the administrative fee and fee for issuance of licence.

One of the conditions that needs to be fulfilled by an applicant who was operational less than two years before applying for a natural gas Wholesale Licence under the Serbian Energy Act is that the applicant has the necessary financial resources for performing the energy activity, as proven through the submission of the documents listed above. There is no requirement for providing a bank guarantee or a cash deposit when applying for a natural gas Wholesale Licence.

Unlike the Wholesale Electricity Market, no Additional Licence is needed for natural gas supply to industrial endcustomers, as the natural gas Wholesale Licence entitles its holders to supply customers for their own needs or for the purpose of resale.

The Energy Act does not explicitly prescribe details on reporting obligations with respect to the maintenance of a licence issued by AERS for the performance of specific energy activities. However, in practice, certain reporting obligations are included in a licence issued by AERS, which relate usually to the obligation to inform AERS of any change that concerns the fulfilment of the conditions for holding the respective licence (eg change of representative/managing director, change of legal form of the company, statutory changes, change of company address) as well as any other changes that can be relevant for the fulfilment of the conditions for holding the respective licence. The conditions under which the license for performing energy activities was granted must be fulfilled during the duration of the license and the wholesale supplier of gas or oil must report to AERS during the validity period of the licence.

B.6 Public service obligations and smart metering

In accordance with the Energy Act, an energy entity that has a license to perform energy activities (production of electricity, combined production of electricity and thermal energy, electricity transmission and transmission system management, distribution of electricity and management of the distribution system, distribution of electricity and management of closed distribution network systems, electricity supply, wholesale supply of electricity, management of the organized electricity market, storage of electrical energy) may be required to provide a public service that will ensure security of supply, regularity, quality and price of supply, environmental protection, including energy efficiency, use of energy from renewable sources and climate protection. Obligations to provide public services must be clearly defined, transparent, nondiscriminatory, verifiable, timelimited, must guarantee the equality of energy entities in the provision of public services and cannot influence the opening of the market.

As for smart metering, the operator of the system determines the technical requirements for the introduction of various forms of smart metering systems and analyses the technical and economic justification of the introduction of smart metering systems, the effects on market development and the benefits for individual categories of end customers.

B.7 Crossborder interconnectors

Serbia has two gas pipeline system interconnections with neighbouring countries (one entry and exit point), these are: (i) Hungary-Serbia (Kishkundorozhma - entry point) and (ii) Serbia-Bosnia and Herzegovina (Zvornik-exit point of interconnection). Both are part of Srbijagas transport system.

At the start of the 2022, construction work started on the gas interconnector that will connect Srbija and Bulgaria. The new gas interconnector will connect the city of Niš with the Bulgarian capital Sofia. The projected capacity of this new gas pipeline will allow flow of 1.8 billion cubic metres of natural gas annually. Finalisation of the pipeline construction is planned for the fourth quarter of 2023.

With its projected capacity, the new gas pipeline will provide an additional 60% capacity increase relative to Serbia's current annual gas needs (approx 3 bcm/y),largely increase the overall security of natural gas supply and contribute to cleaner energy targets.

The new NišSofia gas pipeline (together with the new pipeline under construction between Greece and Bulgaria) will diversify energy sources in Serbia and the Western Balkan region.

C. Energy trading

C.1 Electricity trading

Another vital body is the licensed market operator for an organised electricity market/power exchange, ie the joint stock company South East European Power Exchange (SEEPEX a.d. Beograd) ("SEEPEX"). SEEPEX operates an organised electricity market with the standardised electricity products and dayahead and intraday delivery with the aim of offering these electricity products for trading in Serbia and in the South East Europe region.

Local companies can qualify for admission to SEEPEX if they have obtained either a licence for wholesale supply, a supply licence, or a generation licence, issued by AERS. In addition, foreign companies may trade on SEEPEX when they obtain a licence for wholesale supply of electricity (see sections A.5 and B.5).

Certain end users purchasing electricity for their own consumption (such as industrial consumers) may also become SEEPEX members, as well as TSOs and DSOs in need of quantities for covering grid losses. By September 2022, SEEPEX had 27 registered members. In 2022, there were around 64 licensed electricity suppliers and around 68 participants registered for wholesale supply of electricity in Serbia.

C.2 Gas trading

Serbia imports the entire supply of the foreign natural gas from the Russian federation through two intermediary companies, ie, Yugorosgaz and Russian-Serbian trading corporation (Rusko-srpska trgovinska korporacija).

In 2022, there were reportedly 62 suppliers of natural gas in Serbia. However, a large number of these suppliers were inactive. Srbijagas is still the dominant player on the market.

D. Nuclear energy

Nuclear energy is not generated in Serbia nor is there legal framework regarding nuclear energy.

Furthermore, since 1989, a moratorium is in place that prohibited the construction of nuclear power plants. Additonally, the Act on the prohibition of nuclear power plant construction in the Federal republic of Yugoslavia[29] and the Act on radiation protection and nuclear safety[30] make the construction of such plants in Serbia illegal.

Serbia is also a contracting party to a number of international treaties that regulate the use of nuclear energy:

- Treaty on the Non-Proliferation of Nuclear Weapons;[31]
- Agreement between the SFRY and the International Atomic Energy Agency ("IAEA") on application of safeguards in connection with the Treaty on the Non-Proliferation of Nuclear Weapons[32];
- Convention on Early Notification of a Nuclear Accident[33];
- Convention on Assistance in the Case of a Nuclear Accident or Radiological Emergency[34];
- Vienna Convention on Civil Liability for Nuclear Damage[35];
- The Convention on the Physical Protection of Nuclear Material[36];
- Amendments to the Convention on the Physical Protection of Nuclear Material[37];
- System for reporting of accidents[38];
- Agreement on the Privileges and Immunities of the IAEA[39];
- International Convention for the Suppression of Acts of Nuclear Terrorism[40];
- Statute of the IAEA[41];
- Agreement on Comprehensive Nuclear Test Ban to the Protocol[42];
- Treaty on the Prohibition of the Emplacement of Nuclear Weapons and Other Weapons of Mass Destruction on the Seabed and Ocean Floor and in the Subsoil thereof[43];
- Treaty banning Nuclear Weapon tests in the Atmosphere, in Outer Space and under Water[44]; and
- Convention on the Prevention of Marine Pollution by Waste Ejection[45]; and
- Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal[46].

E. Upstream

NIS is the only company in Serbia engaged and licenced in the exploration and production of oil and gas.

Exploration and Production Block operates an Elemirbased plant for the preparation of natural gas, production of LPG and natural gasoline and CO_2 capture, which has a design capacity of 65,000 tonnes of LPG and natural gasoline per year. In Elemir, there is also the Amine natural gas processing plant, in which HiPACT (High Pressure Acidgas Capture Technology) is applied. The Elemirbased plant is the first HiPACT plant in Europe, and the gas processing method completely prevents CO_2 emissions.

F. Renewable energy

F.1 Renewable energy

On 22 April 2021, Serbia adopted its first renewable energy act (ie, the RES Act). This was a significant step forward in the adoption of the renewables agenda and should help scale up the production and capacities of renewable energy. In accordance with the RES Act, a market based support program that includes feedin premiums may be secured for projects over 500kW and 3MW for wind. The right to feedin premiums is acquired through participation in competitive auctions.

Further support for RES projects is granted in the form of partial balancing support for RES producers. RES producers are relieved of responsibility for their imbalances up to a certain imbalance percentage. For the imbalances above such percentage RES producers must pay a fixed fee for each MWh produced. The percentage and the method of calculation of the fixed fee remain to be specified in the secondary legislation. Such balancing support would be available until establishment of a liquid organised intraday electricity market in Serbia.

Projects under 500kW and 3MW for wind, have the right to secure offtake and feedin tariffs through competitive auctions.

The RES Act enabled self consumption, including joint self consumption, as well as energy communities. On 31 August 2021, Serbia adopted a Decree on prosumers[47], enabling a netmetering scheme for households or housing communities and a net billing scheme for all other prosumers. Already in September 2021, the Ministry published a call for the programme to subsidize households to install solar panels and become prosumers. The priority for Serbia is the adoption of the necessary secondary legislation to enable implementation of the RES Act. Serbia is still far from meeting its goal of using 27% renewable energy in its total annual energy consumption. The share of renewables is not just much lower than the 2020 renewables target, but also lower than the share set in 2009 as a baseline due to rising energy consumption. Serbia lags throughout all three areas: heating, electricity, transport and cooling.

Serbia is a country with a long tradition in hydro power. In Serbia, hydroelectric power plants produce about 80% of the nation's electricity from renewable sources. Up to 2.355MW are produced by large hydropower facilities with the status of RES producers. These are a part of the (EPS) network and do not receive government subsidies. Additionally, EPS owns 15 small hydro power plants with a combined capacity of 20MW. Additionally, 122 small hydro power plants with a combined capacity of 77MW have been built by private investors. 32 micro hydropower plants with the designation of temporary privileged producers and a combined capacity of roughly 30MW are currently being built. After a significant increase in wind capacity in previous years, only 25MW of renewable (hydro) capacities were added in 2020. This stagnation might be attributed to the Covid-19 crisis, which slowed down licensing, contracting, procurement as well as construction and installation.

Only one biomass power plant was constructed with the support of government incentives, while several others are in development and construction.

Biogas plants in Serbia are considerably more numerous than biomass plants. According to the latest data, there are 28 of biomass plants with the total capacity of 27MW, while there are 73 biogas power plants with temporary privileged power producer status and the capacity of about 80MW are under construction. During recent years, large farms in Serbia, especially fattening cattle farms, have constructed biogas plants for organic waste with the purpose of simultaneous profit generation and environment protection.

F.2 Renewable pre-qualifications

Incentives can be acquired for the following types of power plants that produce renewable energy sources:

- hydroelectric power plant with an approved capacity of up to 30 MW;
- hydroelectric power plant on the existing infrastructure with an approved capacity of up to 30 MW;
- biomass power plant;
- biogas power plant;
- wind power plant;
- solar power plant;
- geothermal power plant;
- biodegradable waste power plant;
- landfill gas power plant;
- gasfired power plant from a municipal waste treatment plant water; and
- power plant that uses other renewable energy sources.

Energy entities use incentive measures according to the regulations that were valid at the time of acquiring the right to incentive measures. Conditions under which energy entities have acquired this right cannot be subsequently changed in a way that diminishes or limits them their acquired rights and endangers the economic benefit of their facilities which are subject to incentives.

Incentives for the production of electricity from renewable sources are carried out in a specific incentive period through the system of market premiums and feedin tariffs. These includethe price of electricity, acquiring balance responsibilities, the right to priority access to the system and other incentives prescribed by the Energy Act. Favoured producers are entitled to only one incentive system for the same power plant.

Market premiums are a type of operational state aid that represents an addition to the market price of electricity that users of the market premium delivered to the market, and which is determined in Eurocents per kWh in the process auction. Market premium users sell electricity on the electricity market. A market premium can be acquired for all, or part of the capacity power plants. The market premium is paid on a monthly basis for electricity that was delivered by the power plant to the power system. The Government, at the proposal of the Ministry, regulates the type, method, and conditions of acquisition, realisation, and termination of the right to the market premium, as well as the method determining the reference market price. For the purposes of auctions, the AERS determines the maximum market premium or maximum purchase price for electricity per kWh. Methodology for determining the maximum market premium or height maximum purchase prices is prescribed by the AERS.

The right of market premiums is acquired in the auction procedure. The Ministry conducts auctions based on the available quotas which are prescribed by the Government. Qualification is the elimination phase of the auction procedure in which a selection is carried out of registered participants based on the fulfilment of the following conditions:

- types and approved power of the power plant;
- the planning basis for the construction of the connection of the power plant to electro energy system;
- if the auction participant acquired:
  - legally valid energy permit for the power plant,
  - locational conditions (technical planning conditions), and
  - a financial security instrument for the seriousness of the offer.

The Government may prescribe other qualification requirements for market premiums.

F.3 Biofuel

From the regulatory point of view, no significant improvements have been made in recent years, after a very prolific period in the middle of the past decade. It shall be noted that more efforts have been invested in energy efficacy (residential use absorbs as much as 1/3 of TFEC, not considering the phenomenon of illegal logging for heating purposes, which according to some sources might be substantial). Efforts have been made also to valorise biomass for district heating and/or heating of public institutions, as well as for the promotion of agropellets (abundant production of wood pellets is generally exported). However, the overall economic situation is probably the biggest obstacle for the deployment of effective measures in support of RES and bioenergy.

Notwithstanding the relevant potentials in terms of feedstock availability, technical competences, and specific measures for attracting foreign investments, biofuel deployment and supply are still extremely limited in Serbia. This is a result of different factors spanning from domestic market weakness (low purchasing power and willingness to pay a green premium), to lack of political will to opt for solutions that would entail high social costs. This is also reflected in the lack of incentives for biofuels. At present, four plants with a total annual capacity of 0.07 Mtoe exist in the country, yet none of these plants are currently producing biodiesel.

Biofuels that are placed on the market must meet the conditions established by regulations on the quality of biofuels, as well as technical and other regulations related to their circulation.

In order to achieve the planned share of renewable energy sources in the final energy consumption in traffic by 2030, incentives can be granted to producers of biofuels. Incentives for the production of biofuels can only be granted for plants that produce advanced biofuels, save in the case where incentives for biofuels are granted in the form of investment state aid. Incentive measures cannot be granted for the production of biofuels that are subject to the fuel supplier's obligation to place them on the market, unless such fuels meet the sustainability criteria and if the provider of state aid explains to the competent authority for state aid control that their placing on the market would only be possible if the supplier's obligations led to a significant increase in costs for consumers. Funds used as an incentive to reach the share of renewable energy sources in traffic are provided in the budget of the Republic of Serbia. This is in the amount determined for each year by the Act governing the budget of the Republic of Serbia, within the department of the Ministry, and is in accordance with the limits established in the fiscal strategy for the current year, with projections for the next two years.

The Biofuel sector regulated in the same fashion as Oil in the Serbian Energy Act (see section B).

G. Climate change and sustainability

G.1 Climate change initiatives

Serbia is a signatory of the Kyoto protocol[48] and the Paris climate agreement[49]. The Climate Change Act[50] ("CCA") was adopted in March 2021. CCA prescribes the adoption of the Low Carbon Development Strategy with an Action Plan within two years from its adoption. Also, it sets the basis for the establishment of a national system for policies, measures, and projections, which will be operational upon adoption of the relevant bylaws. The CCA stipulates that the Serbian Environmental Protection Agency establishes and maintains the GHG inventory and prepares the inventory report. A set of bylaws, currently being drafted, list the types of data and the bodies and competent authorities requested to submit data on GHG emissions to the Agency, which will ensure data quality control.

Serbia complied with its reporting obligations under the Large Combustion Plants Directive for 2020 and provided emission scenarios considering ongoing investments. In 2020, the emission of all three pollutants slightly increased, while a slight decrease in dust emissions was recorded for plants under the NERP.

G.2 Emission trading

For decades the production of electricity and heat has been contributing the most to CO_2 emissions in Serbia, followed by industry, according to International Energy Agency data.

The main regulation source for emissions in Serbia is the 2016 Directive on measurements of air pollutant emissions from stationary sources of pollution[51]. This regulation prescribes the method, procedure, frequency, and methodology of measuring the emission of polluting substances from stationary sources of pollution, the criteria for establishing measuring points for measuring emissions, the procedure for evaluating the results of emission measurements and compliance with the prescribed norms, the content of the report on the performed emission measurements, as well as the methods, the method of measuring the emission of polluting substances, the criteria for the selection of measurement sites, the method of processing the measurement results from combustion plants, and the method and deadlines for submitting data on the measurement of emissions from combustion plants. The provisions of this regulation apply to combustion plants, defined by the regulation prescribing the limit values of emissions of pollutants into the air from combustion plants and other stationary sources of pollution.

G.3 Carbon pricing

A number of the Western Balkan countries, namely Bosnia and Herzegovina, Montenegro, and North Macedonia, have taken the first tangible steps to introduce carbon dioxide (CO_2) taxation. This aims to speed up decarbonization, but also to avoid paying the European Union's (EU) carbon tax on imports, which the bloc plans to impose from 2026.

In the future, it is expected that Serbia will speed up its carbon taxation regulation in order to prevent taxation for exports to the EU, because that would pose a significant cost considering about 70% of Serbian exports go to EU countries.

G.4 Capacity markets

The Energy Act envisages that the TSO adopts Rules on Cross-Border Transmission Capacity Allocation, which are subsequently approved by the Energy Agency.

The rules regulate the procedure for allocation of cross-border electricity transmission capacity on a nondiscriminatory and transparent basis.

H. Energy transition

H.1 Overview

In light of the current energy crisis in Europe and around the world, the regional approach to energy supply and the process of switching to green energy sources are particularly crucial. Nearly a third of the country is suitable for the construction of solar power facilities, and Serbia enjoys 30% more hours of sunshine per year than central Europe. The country's whole energy system is currently in the adaptation phase in anticipation of the future increased proportion of output from renewable sources. The Ministry has decided to finance the installation of solar panels in homes. Since the Western Balkan countries are all undergoing an energy transition at the same time, a coordinated strategy makes it simpler to finance green energy and move away from coal.

Financing of transition and integration projects can be provided through donors and favourable loans from international financial institutions. The European Union in Serbia finances key regional energy connection projects through grants. The most significant ongoing projects in this area are the construction of the Serbia-Bulgaria Gas Interconnector and the Trans-Balkan Electricity Corridor. The total amount of EU grants for these two projects is more than €70 million. For 2022, the EU is preparing grant support for the entire Serbian energy sector in the amount of €100 million.

H.2 Renewable fuels

Hydrogen

Green hydrogen has been identified in the RES Act as an energy product to be promoted and developed in Serbia. It can be used in heat energy generation, transport, and industry. This energy product is produced by the wellknown process of electrolysis, but in order for the hydrogen to be “green” the power used for its production needs to come from renewable sources (nongreen hydrogen currently in use in the industry is generated from natural gas). Hydrogen combustion produces water which makes it completely environment safe. Introduction of green hydrogen into the cycle would enable the storing of electricity and its use during the periods without wind or sunshine, thus making the green energy generation system highly sustainable. The production of hydrogen, a new source of energy in Serbia, will be part of the country's energy development strategy until 2050, which is planned to make the country a world leader in this field.

Ammonia

There is no mention of Green Ammonia in the Serbian renewable energy source plan or in any legislation.

H.3 Carbon capture and storage

Up until now there has been no mention of Carbon capture and storage in any Serbian legislation.

H.4 Oil and gas platform electrification

There is no mention of oil and gas platform electrification in any Serbian legislation.

H.5 Industrial hubs

The majority of the country's manufacturing jobs are located in the north, particularly in the area around Belgrade, which benefits from a developed labour force, an extensive infrastructure and the highest concentration of businesses that can act as both consumers and suppliers of product parts.

An industrial area lies in a belt along the Zapadna (Western) Morava River from Užice in the west, through Čačak and Kraljevo to Kruševac and Niš. Among the principal products of this area are automobiles, trucks, tyres, batteries, radio and television equipment. Kragujevac is the site of Serbia’s main automobile factory, operated by the Italian company Fiat. Smederevo, east of Belgrade, has a major iron and steel facility, but it lacks ready access to quality coking coal.

Textile production is prominent in Novi Sad and other towns of the Vojvodina as well as the city of Novi Pazar in the South.

H.6 Smart cities

"Smart city" implies the construction of a network of transmitters and the development of an information system that should enable the economical application of various services. "Smart cities" use the socalled Internet of things (IoT) devices, such as sensors, lights, and meters for data collection and analysis.

In Serbia, initiatives such as the Smart City festival, Smart City regional conference SEE19 and individual competitions eg, "The best solutions for a smart city", have begun to approach the idea of developing smart cities, however, little more has been organised.

The Implementation and development of 5G networks in Serbia is done, in part, with cooperation with the Chinese company Huawei, which has created solutions for more than 160 smart cities in more than 100 countries of the world. The company has also established open service platforms and collaborative innovation labs, certification, and verification, and has a good workflow of projects, rich experience, and a welldesigned system of delivery.

In countries that have introduced the 5G network, Internet speeds range from 200 to 490 Mb/s, while the average speed in Serbia is 49 Mb/s. So, while there is talk about developing smart cities in Serbia those ideas never leave the ground and so far, the only visible trace of smart city infrastructure are parking displays in the streets.

I. Environmental, social and governance (ESG)

Serbia faces many difficulties while incorporating ESG factors. The lack of environmental protection is widely recognized, with Belgrade frequently ranking among the world's most polluted cities. Regarding recent claims of forced labour or slavery of Vietnamese laborers in the town of Zrenjanin, for instance, respect for human rights standards is also in the forefront of public attention.

The problem is that Serbia has no legislation addressing ESG concerns besides traditional regulation in the spheres of environmental, labour, and criminal law and similar. While ESG per definition goes beyond regulatory compliance, hard law requirements are still important considering the objections that voluntary commitments to ESG standards do not bring desirable results. This comesfrom the civil sector but is also expressed in the European Parliament’s resolution that advanced a draft directive on corporate due diligence. Despite the absence of legislative obligations, the private sector in Serbia demonstrates several instances of sectoral selfregulation and the promotion of voluntary commitments, particularly through programs run by bigger, multinational corporations. There are supplier codes of behaviour that account for the majority, if not all, ESG factors. ESG policies are also disclosed by banks, for instance in lending.

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Energy law in the Slovak Republic

Recent developments in the Slovak Republic energy market

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Support of hydrogen

With the increased focus of the European Union ("EU") on hydrogen, the Slovak Government ("Government") (especially the Ministry of Economy) is pursuing a variety of activities focused on promoting hydrogen in Slovakia. The Government's plan is to become a regional leader in this sphere.

In June 2021, the government introduced the National Hydrogen Strategy to be followed by an action plan with 14 concrete measures and investment opportunities. Some of these measures have already started to materialise, such as:

- EP Infrastructure (shareholder in variety of Slovak energy companies), Eustream (gas TSO), NAFTA (sole operator of gas storage facilities) and RWE Supply & Trading are looking to jointly explore the potential development of a state-of-the art blue hydrogen production facilities in eastern Slovak Republic. To this end, the companies have now signed a Memorandum of Understanding and the plan is for RWE Supply & Trading to off-take and export the produced hydrogen to Germany and other RWE core markets in Western Europe where the hydrogen could then be transmitted through a repurposed Eustream gas pipeline to Germany;
- The prototype of the Slovak hydrogen car MH2 was presented at the World Expo Dubai 2020 held in October 2021 by Richard Sulík, the Minister of Economy. The hydrogen car was developed by the Faculty of Mechanical Engineering of Technical University in Košice and Matador Group. The MH2 hydrogen car should accelerate from zero to 100km/h in four seconds and the maximum speed is about 250km/h. The MH2´s hydrogen concept uses a specific method of storing hydrogen that requires intelligent temperature management;
- At the World Expo Dubai 2020, the Slovak Ministry of Economy also presented a hydrogen bus, the Midibus. This is a prototype based on the conventional Iveco Daily vehicle and offers 12 seats and a range of less than 200km. In March 2022, the hydrogen-electric minibus was launched;
- BCF ENERGY entered into a contract to construct 40 service hydrogen filling stations, which will be part of BENZINOL Slovakia Group in the Slovak Republic. BCF ENERGY is preparing the production of green hydrogen by building factories in Modrý Kameň, Pezinok, Malacky and Trenčín. The daily production of green hydrogen in these factories is estimated to be around 4,000kg. In 2023/2024, BCF ENERGY plans to fully launch the production and sale of green hydrogen; and
- Regional trains powered by hydrogen fuel cells could be put into operation by 2025. Railway companies are planning to operate these trains in the Upper Nitra region as they are currently using diesel motor trains because 113km of railroad is not electrified. The project will depend on the construction of a specialised depot for hydrogen trains in Prievidza. The test operation and certification of the first two prototypes is expected to be completed by the end of 2025; commercial operation will then follow.

Interestingly, no specific hydrogen legislation has been introduced to date despite the increasing focus on the use of hydrogen.

RES auctions

In early 2020, the first RES auction under the new EU rules was planned to take place. However, the auction was cancelled due to the outbreak of COVID-19 soon after the new government took control in March 2020.

The Government opened a new auction in May 2022. The intention was to announce a technology neutral auction with an indicative allocation of €51.37 million. Eligible technologies include photovoltaic ("PV") power plants, wind power plants, biomass and biogas power plants, as well as geothermal sources. The maximum amount of support per project will be €15 million. In total, 120 projects were submitted in this auction.

Auctions for repowering hydroelectric and biogas plants are also planned for the first half of 2023. The plan for 2022 also includes putting in place support mechanisms for battery systems and pumped storage hydropower which is aligned with increasing system flexibility.

Forced prolongation of RES support term

For some time, the Government has considered the introduction of certain forms of repowering of RES facilities. In 2021 the Government adopted a specific measure to provide support for five years but in a way that the remaining amount of support to which producers are entitled will be recalculated for the extended period. The total amount of support will therefore remain the same, but it will be paid out during the course of longer period in reduced amounts. This proposal has two main aims, firstly, to lower the financial impact of the RES support scheme on the public sources and secondly, to keep the existing RES facilities in operation for a longer period and thus keeping the required RES share.

Initially, this repowering measure was to be only adopted on a voluntary basis, but following various changes it became obligatory for certain RES facilities. This obligatory regime was applied to facilities which received additional payment (as part of a feed-in tariff) in the amount of more than €75,000 over the previous year and in average in the amount of €150 per MWh. According to public statements from authorities, this has affected 440 solar power plants, which have, according to the ministry officials, already repaid the initial investment. The operators of such plants were required to apply for prolongation within a short time period as otherwise the regulator would decide on prolongation even without their application (and, consequently, they could also impose a fine up to €100,000).

According to publicly available information, voluntary prolongation was not attractive to RES operators.

Ongoing construction of Mochovce nuclear power plant and reactors in Jaslovske Bohunice

Slovenské elektrárne, a.s. is the largest electricity generator in the Slovak Republic. The company operates two nuclear power plants, two thermal (fossil) and biomass power plants, two PV power plants and 31 hydroelectric power plants, and continues with completion of units three and four of the Mochovce nuclear power plant (with planned installed capacities of 471MWh each).

This construction commenced in 2008 with operations expected to begin in 2012. However, the operation was repeatedly postponed, and the plan changed to start operating during the first few months of 2022 (unit four in 2023). On 25 August 2022, the Nuclear Supervisory Authority issued a final decision that allows the third unit of the nuclear power plant in Mochovce to be put into operation. The new nuclear unit will have an installed capacity of 471MWtt, which will cover about 13% of the total electricity consumption. After the test operation and reaching maximum output, the Slovak Republic will become a net exporter of electricity. Furthermore, the expected investment costs have increased multiple times, and to date stand at €6.2 billion.

The company also planned to construct a new reactor at one of the Slovak Republic's two nuclear power plants, Jaslovske Bohunice. However, this project has been on hold for several years, mainly due to financing issues and potential exit of ČEZ, a Czech partner, from the project. The project is still on hold to enable the Mochovce power plant to commence operations, but will go ahead in the future given the Government's intention. The reactor which is planned to be constructed will be a III+ generation reactor with maximum installed capacity of under 1,700MW with a 60-year projected lifetime costing around €4 billion to €6 billion.

New interconnections of electricity grid

The commercial operation of the new interconnection of electricity grid between the Slovak Republic and Hungary (new lines 2x400kV Veľký Ďur – Gabčíkovo – Gönyű and 1x400kV Rimavská Sobota – Sajóivánka) began in spring 2021.

This project aimed to eliminate a bottleneck in the transmission system of the Slovak Republic by enabling the connection of a new electricity facility (producing electricity) to the existing Slovak electricity system while at the same time increasing the installed capacity of existing sources connected to the Slovak electricity system. This new interconnection will also enhance cross-border sales and trading of electricity with particular focus on Balkan states.

Overview of the legal and regulatory framework in the Slovak Republic

A. Electricity

A.1 Industry structure

Key market players

Slovenské elektrárne, a.s. ("SE") is the largest electricity generator in the Slovak Republic. The company operates two nuclear power plants, two thermal (fossil) power plants, two photovoltaic ("PV") power plants and 31 hydro power plants ("HPPs"). The total installed capacity of power plants owned or operated by SE as of 2021 was 4,175MW. The shareholders of the company are the Italian company Enel (33%), private equity group EPH (33%) and the Slovak State ("State") (34%).

There are three main regional energy companies in the Slovak electricity market: Západoslovenska energetika, a.s., Stredoslovenská energetika, a.s. and Východoslovenská energetika a.s. The E.ON group has held a stake in Západoslovenská energetika, a.s. since 2002, while the State remains its majority shareholder (51%). The shares in Stredoslovenská energetika, a.s. are owned by the State (51%) and the EPH (49%). The shares in Východoslovenská energetika a.s. are held by the Slovak state (51%) and by the E.ON group (49%). Pursuant to the Third Energy Package, transposed into Slovak legislation by the Act No. 251/2012 Coll. on Energy (the "Energy Act"), the energy companies Západoslovenská energetika, a.s., Stredoslovenská energetika, a.s. and Východoslovenská energetika a.s. have unbundled their distribution system operations into their 100%-owned subsidiaries Západoslovenská distribučná, a.s., Stredoslovenská distribučná, a.s. and Východoslovenská distribučná, a.s.

Slovenská elektrizačná prenosová sústava ("SEPS") is the only transmission system operator ("TSO") in the Slovak Republic and is fully owned by the State through the Ministry of Finance of the Slovak Republic. SEPS ensures that electricity is transmitted from power plants to the distribution network and major customers. Further, SEPS bears responsibility for the administration of imports, exports and the transit of electricity (including cross-border transit).

As of 1 January 2011, OKTE, a.s. (100% subsidiary of SEPS) organises the short-term electricity market (the day-ahead market) in the Slovak Republic. Further, OKTE is also an imbalance biller, ie it bears responsibility for the settlement of imbalances of certain market participants (see section C.1) and also acts as payer of certain parts of promotion of renewable sources.

National regulatory authority

The Ministry of Economy of the Slovak Republic (the "Ministry") and the Regulatory Office for Network Industries ("RONI") are the competent regulatory authorities in the energy sector. RONI is mainly responsible for:

- transparent, non-discriminatory and efficient competition in the electricity, gas and other regulated sectors;
- establishing rules for the functioning of the electricity and gas market;
- setting conditions for connection and access to national networks;
- granting authorisation for regulated activities; and
- price regulation.

Compliance with the obligations imposed by applicable Slovak energy regulations is enforced by the State Trade Inspection.

The nature of the market

The Slovak electricity sector is only partially privatised, and the Slovak state remains the majority shareholder in most of the Slovak Republic's key electricity companies (although without managerial control).

The liberalisation of the electricity market in the Slovak Republic has gradually taken place following the partial privatisation of the regional suppliers. Since 1 July 2007, all customers (including household customers) can choose their electricity supplier.

Key legislative, regulatory and contractual features

Act No. 251/2012 Coll. on Energy (the "Energy Act") sets out the main provisions pertaining to the energy sector.

Further energy legislation includes:

- Act No. 250/2012 Coll. on the Regulation of Network Industries ("Act on Regulation");
- Act No. 309/2009 Coll. on the Promotion of Renewable Energy Sources and Highly Efficient Cogeneration ("Renewable Energy Act"); and
- Decree of RONI No. 24/2013 Coll. laying down Rules for the Operation of the Electricity and Gas Internal Market.

Ancillary rules are contained in the regulations of the Ministry, the decrees of RONI, the Transmission System Code, the Transmission System Business Code, the Business Rules of SEPS, the Operating Order of SEPS, the Dispatching Order of SEPS, the Distribution System Code and the Operating Order of OKTE.

The extent of implementation of the EU Directives

The Third Electricity Directive was transposed into Slovak law in 2012 in the form of a new Energy Act and new Act on

Regulation. The new Energy Act implements the full ownership unbundling model, under which electricity generation and supply will have to be fully separated from electricity transmission. Furthermore, the Energy Act contains provisions to extend the rights of the final customer and implements various changes, eg regarding the scope of business activities in the energy sector which are subject to the licensing regime. In addition, Directive (EU) 2019/944 was also transposed to the new Energy Act in 2020.

The licensing regime

The generation, transmission, distribution and supply of electricity (including electricity trading) and the activities of the organiser of the short-term electricity market must be authorised by RONI. Authorisations are granted for an unlimited period unless an applicant applies for a limited authorisation.

Authorisation is not required for the generation and supply of electricity by power plants with a total installed capacity not exceeding 1MW. Furthermore, authorisation is not required for the generation and distribution of electricity for personal consumption or for the supply, transmission and distribution of electricity in cases where electricity is supplied to third person(s) (excluding, however, final customers in local distribution networks) for a purchase price with no profit margin. Finally, no authorisation is required for electricity generators with small electricity generating facilities that are not applying for payments under the Renewable Energy Act, are final household customers and are generating electricity only in small amounts. In such cases, only a notification of such generation to RONI is required.

Prior to constructing energy facilities, a constructor has to obtain a certificate from the Ministry stating that the relevant project complies with the long-term objectives of the Slovak Republic's energy policy. Solar power facilities located on a building with an intended total installed capacity of less than 100kW per building, other (non-PV) energy facilities with an intended total installed capacity of less than 1MW and energy facilities for electricity distribution to be operated by a distribution system operator ("DSO") are exempt from this requirement.

A.2 Third party access regime

The Slovak Republic operates a system of regulated third party access to the transmission and distribution systems. Generally, all energy market participants are entitled to be connected to the transmission and distribution systems provided that the technical and business conditions of the system operator have been complied with.

Access to the system is granted on the conclusion of a connection contract with the system operator. The transmission is ensured under an agreement on access to the transmission system (electricity transmission) and distribution is ensured under an agreement on access to the distribution system and the distribution of electricity.

The connection contract ensures physical connection to the system and enables the participant to supply or consume electricity. The electricity market participant applying for a connection must pay for a connection at the site of the system operator.

Following the conclusion of the connection contract, the relevant parties enter into an access and transmission/distribution contract under which the agreed capacity is automatically reserved for the relevant market participant. Charges are based on the tariff regulated by RONI.

A.3 Market design

The electricity market of the Slovak Republic is a single market with a pool of energy players. There are no separate capacity or energy markets. The market coupling with neighbouring countries (see section C.1) has, in recent years, been important in creating a market design due to the increased possibility of cross-border electricity trade.

Activities that are subject to RONI's prior licensing procedures in the energy sector are listed in section A.1 (the licensing regime). An entity may apply for more than one regulated activity.

The Energy Act requires that new entrants to the Slovak electricity market:

- in case of natural persons, be residents of the Slovak Republic or have permanent residence in one of the member states of the European Economy Area; or
- in case of legal entities, have their registered offices (seat, enterprise or a branch office) in the Slovak Republic.

Other conditions for the licence to be issued include the personal integrity and sufficient professional qualifications (of the applicant or an appointed representative) to perform the relevant activities and proof of compliance with the technical prerequisites for the performance of relevant activities applied for.

In line with the Third Electricity Directive, the Energy Act enables suppliers of electricity from EEA Member States to enter the market via a simplified procedure.

For actual operation on the Slovak market, electricity market participants must conclude specific agreements, mainly with TSOs or DSOs (see section A.2).

A.4 Tariff regulation

Charges for the use of distribution or transmission systems are subject to tariff regulation conducted by RONI. The methodology for tariff regulation is drafted by RONI on the basis of the Act on Regulation and of the Regulatory Policy for the respective period. For the period from 2017 to 2022, tariff regulation methodology applicable to the electricity sector is provided under the Decree of RONI No. 18/2017 Coll. setting out the rules for the Tariff Regulation in Electricity Sector.

For use of distribution or transmission systems, the methodology for determination of charges is based on RONI setting a maximum price for such services. The same methodology is also used for support services, system services of system operators as well as for supply of electricity to consumers and small businesses. Tariffs are set by RONI for one year, *ex ante*.

A.5 Market entry

As to the market entry regime in Slovak Republic, see section A.1 (the licensing regime) and section A.2 for further conditions.

A.6 Public service obligations, smart metering and electric vehicles

Under the Energy Act, the Slovak Government can approve obligations in the general economic interest (ie PSOs) in the energy sector on proposal of the Ministry of Economy. In addition, the Ministry of Economy can also impose further obligations in the general economic interest on electricity producer, system operator and network operator, electricity supplier and gas supplier and storage system operator to ensure security, regularity, quality and price of electricity supply or utilisation of renewable energy sources ("RES"), co-generation, and domestic coal for the generation of electricity.

In practice, the Ministry of Economy has imposed various PSOs on electricity market participants with respect to the use of domestic coal to generate electricity. For example, an obligation in 2016 to generate 1584GWh of electricity from domestic coal.

The Energy Act introduced smart metering. Further details are provided in the Regulation of the Ministry of Economy No. 358/2013 Coll. Under these rules, smart metering devices were gradually introduced by DSOs up to 31 December 2021. The Slovak Republic aims to install around one million smart meters, enabling demand response and allowing consumers to better manage their energy consumption.

Generally, the use and charging of EVs is not specifically regulated under the Slovak energy law, while there are certain support mechanisms, such as tax treatment or better parking options.

A. 7 Cross-border interconnectors

The Slovak Republic has three 400kV and two 220kV cross-border interconnectors with the Czech Republic, four 400kV with Hungary, one double 400kV line to Poland and one 400kV to Ukraine. The Slovak electricity system is not yet connected to Austria. There are plans to build other lines to Poland.

B. Oil and gas

B.1 Industry structure

Key market players

Slovenský plynárenský priemysel, a.s. ("SPP") is the dominant market player in the natural gas sector in the Slovak Republic (in 2020, SPP had about 58% of the market share). Since 2012, SPP has also been a supplier of electricity. SPP is 100% owned by the State.

SPP has legally unbundled its transportation and distribution activities with effect from 1 July 2006. Currently, two main subsidiaries of SPP, eustream, a.s. (SPP transmission) and SPP, distribúcia, a.s. (SPP distribution), operate in the Slovak gas market. In these entities, 49% of shares are held by Slovak Gas Holding, (owned by EPH) and 51% of shares are held by the State.

Eustream, a.s. transmits Russian natural gas from the Slovak-Ukrainian border to the European market, representing 20% of the total consumption of natural gas in the EU. From January 2020 to July 2021, eustream, a.s. transmitted 48 (from a capacity of 73) billion cubic metres (bcm).

The import of natural gas from Russia through the territory of the Slovak Republic is carried out on the basis of a long-term supply and transportation contract with Gazprom Export, the Russian exporter of natural gas.

The nature of the gas market

Since 1 July 2007, all customers, including household customers, have been able to choose their own gas supplier. This option is used mainly by large and medium-sized companies. The household market is still primarily controlled by the major player SPP with a household market share of about 70%, although this has been declining in recent years due to further liberalisation resulting from the adoption of the new Energy Act.

Nearly 100% of the Slovak Republic's domestic gas consumption is covered by the import of Russian gas. In early 2009, as a result of the Russian-Ukrainian gas dispute, the Slovak Republic was left without gas for almost two weeks. Following this gas crisis, the government decided to search for possible alternative gas suppliers. Reverse flow was also established in the cross-border interconnection point with Ukraine.

Alternative policies and future gas transit options are under discussions, including the use of liquified natural gas ("LNG") in the future, possibly also by using Danube as a transport measure.

Key legislative, regulatory and contractual features

The Energy Act, the Act on Regulation and the Decree of RONI No. 24/2013 Coll. setting out Rules for the Operation of the Electricity and Gas Internal Market apply to the gas sector.

RONI is the national regulatory authority for the gas sector (see section A.1).

The extent of implementation of the EU Gas Directives

The Third Gas Directive was transposed into Slovak legislation in 2012 in the form of an entirely new Energy Act and a new Act on Regulation. The new Energy Act stipulates that SPP as the gas TSO may either be (i) fully ownership unbundled; (ii) organised as an independent system operator ("ISO"); or (iii) organised as an independent transmission network operator ("ITO"). In November 2012, the Slovak Government chose the ITO model for the unbundling of SPP. In addition to the unbundling rules, the Energy Act sets out extended rights of a final consumer.

The licensing regime

Business activities in the gas sector, ie the generation, transportation, distribution and supply of gas and operation of facility for distribution of LPG, may only be pursued under a licence granted by RONI. In order to be granted a licence, the applicant must meet general legal conditions (see section A.3).

Only a notification to RONI is required for the production and supply of gas from biomass or biogas, the sale of compressed natural gas for the propulsion of motor vehicles, the sale of LPG in pressurised vessels and for the propulsion of motor vehicles and transport of LPG in pressurised vessels, for the generation and distribution of gas for personal consumption and in cases where gas is supplied and distributed to third person(s) for a purchase price with no profit margin.

B.2 Third party access regime to gas transportation networks

Transportation network operators and distribution network operators must provide connection and access to the transportation and distribution networks on a non-discriminatory basis to all market participants applying for such access, if the technical and business conditions are met.

The network operators may reject requests for access to the network in the event of a lack of transportation or distribution network capacity. RONI may grant the transport network operators or gas storage operator temporary exemption from the obligation to provide third parties with access to the relevant facility if such access would result in serious economic losses of the gas supplier due to existing take-or-pay contracts and provided that such losses cannot be dealt with by other means.

The business conditions of network operators must stipulate the prices for granting access or contain the methods for calculating such prices, which are subject to RONI approval.

Access is provided on a contractual basis. The Energy Act differentiates between:

- an agreement for connection to the network; and
- an agreement for access to the network and the provision of gas transportation or distribution.

An application for access must be submitted to the operator of the transport network at least 15 working days (or a shorter period, if negotiated with system operator) before the intended day of transportation, or to the operator of the distribution network 15 or 25 days (depending on the gas capacity applied for in comparison to agreed capacity or a shorter period, if negotiated with the system operator) before the start of distribution. Transportation capacity must be granted within ten days, and distribution capacity within ten to 20 days of receipt of the application by the network operator.

Following the submission of application for access to the network the market participant is granted either a fixed transportation capacity, or, if the applicant requires and there is no available fixed capacity, an interruptible capacity.

Access to the transmission system is entry-exit based. For entering and exiting the system, customers can choose from entry/exit points on borders and from a domestic point, which is a virtual aggregated interconnection to and from domestic storage and distribution networks. At the domestic point, the TSO provides a virtual trading service and the distribution system is based on the entry-exit regime.

B.3 LNG terminals and storage facilities

There are no LNG terminals in the Slovak Republic and no specific legislation addressing this area. The Slovak Government is supporting the construction of the Adria LNG terminal in Croatia. Eustream, a.s. is also supporting this project with the possibility to link the Adria terminal to the Polish LNG terminal in Świnoujście. In addition, operators of Slovak harbours have initiated Environmental Impact Assessment ("EIA") proceedings for the construction of a LNG terminal on Danube in the Slovak capital city Bratislava.

Operators of storage facilities must provide access to any market participant on a non-discriminatory basis provided that the technical and business conditions are fulfilled. The application for access must be submitted to the storage operator 40 days (or a shorter period, if negotiated with the system operator) before the intended storage. An agreement on granting access to the storage facility must be concluded within ten days after granting the capacity. The capacity may be granted as fixed or as interruptible capacity if there is no available fixed capacity or the system operator decides that the interruptible capacity is possible.

B.4 Tariff regulation

Charges for the use of distribution or transportation systems are subject to tariff regulation conducted by RONI. The methodology for tariff regulation is drafted by RONI on the basis of the Act on Regulation and of the Regulatory Policy for the respective period. For the period from 2017 to 2022, tariff regulation methodology applicable to the gas sector is set out in the Decree of RONI No. 223/2016 Coll., which sets out Rules for Tariff Regulation in the Gas Sector.

The methodology to determine charges for the use of the distribution or transportation systems is based on the maximum price for such services being set by RONI, or by the determination of a calculation mechanism for the maximum price. One exception is the determination of the exact price for access to the transportation system and for transport (through comparison with another EU Member State). Tariffs are set by RONI for one year, *ex ante*.

B.5 Market entry

The conditions for market entry with respect to gas are the same as those for electricity (see section A.3).

B.6 Public service obligations and smart metering

PSOs for the gas sector are similar to thosefor electricity sector (see section A.6). The Energy Act contains the provision relating to the installation of smart metering systems in gas sector but the secondary legislation setting out categories of customers and deadlines for such installations have not been adopted yet.

B.7 Cross-border interconnectors

Natural gas from Russia and Ukraine is transported through the Slovak Republic to the Czech Republic and Austria. The Slovak gas transportation system is connected to Ukraine (by two interconnectors), Hungary, (by newly build connection), the Czech Republic and Austria. Reverse flow is enabled in the existing interconnections at the Czech and Austrian border. One interconnector with Ukraine (Budince) serves only as the exit point to the transmission network of gas facilities in the territory of Ukraine.

C. Energy trading

C.1 Electricity trading

The Energy Act defines the market participants in the Slovak electricity market, which are:

- generators of electricity;
- TSOs;
- DSOs;
- electricity suppliers, including wholesale electricity traders;
- electricity customers (with a special protected category of household customers); and
- the organiser of the short-term electricity market.

Electricity trade can be divided into wholesale (sale and purchase of electricity with a view to its further sale) and sale to customers (retail). Electricity can be traded in several ways: bilateral contracts (over-the-counter trading, the most common form), auctions, energy exchange (organised in Slovakia by the company SPX) or market coupling (the Slovak bidding zone has become a part of the single day-ahead electricity market in Europe (SDAC)). Electricity can also be traded on the short-term electricity market.

Imbalances

Under the Energy Act, the organiser of the short-term electricity market, OKTE, is mainly responsible for settling imbalances and entering into contracts with individual electricity market participants for the settlement of imbalances. Electricity market participants can choose to assume responsibility for imbalances on their own or transfer them to others. Transferred responsibility must be established by agreement. Electricity suppliers generally must enter into contracts for the settlement of imbalances with OKTE. On the other hand, household customers' responsibility is transferred to the respective electricity supplier and settled jointly as one balancing group.

Cross-border trade

SEPS organises the cross-border trade of electricity. It determines and publishes on its website the transmission capacity of the connection lines on the territory of the Slovak Republic in such a way that it is available to market participants for the import or export of electricity ("Freely Tradable Capacity"). SEPS publishes adjusted annual, monthly, weekly and daily transmission capacity.

Freely Tradable Capacity is allocated to electricity market participants by auction, ie on the basis of market participants' requirements and quotations within deadlines and under the terms and conditions of SEPS. SEPS publishes the rules and results of the auctions on its website. Rules on market coupling and the activity of regional auction operator CAO Central Allocation Office GmbH have an influence on cross-border trade.

Market coupling

Since 2021, the Slovak, Czech, Romanian, Hungarian, Polish, German and Austrian TSOs have been operating an interconnection project of the national markets through the daily organised markets. The cross-border transmission capacity necessary for electricity transmission from one national market to another is allocated in the form of a daily implicit auction.

C.2 Gas trading

Only holders of gas supply licences may sell gas to customers or to other market participants. Gas suppliers can:

- buy and sell gas to other gas market participants;
- have gas supplied by them, if the technical and business transportation and distribution conditions are met, to be transported, distributed and stored; and
- access the transportation and distribution system and storage facilities.

The main instruments of gas trading are bilateral contracts.

In September 2010, SPP arranged for the first (and only one so far) auction sale of natural gas in the Slovak Republic.

D. Nuclear energy

Relevant legislative framework

Act No. 541/2004 Coll. on the peaceful use of nuclear energy (the "Atomic Energy Act") regulates the nuclear energy sector. It primarily stipulates the conditions for nuclear safety, the management of radioactive waste and spent fuel, the emergency system and liability for damage caused by a nuclear event and supervision of cross-border transportation of radioactive waste. The Atomic Energy Act is fully compatible with EU legislation, including Council Directive 2009/71/Euratom of 25 June 2009.

Overview of the nuclear sector in the Slovak Republic

The Slovak Republic operates two nuclear power plants in Jaslovske Bohunice and Mochovce. Almost 53% of the total electricity generated in 2020 in the Slovak Republic was produced by nuclear power plants.

In the Jaslovske Bohunice Nuclear Power Plant, electricity is generated in the V2 unit, which has a capacity of 2x506MW. When building the V2, the world's most widespread use of pressurised water reactors was adopted, using the Soviet-era WWER 440 design. The former V1 reactors have been classified as non-upgradeable and were shut down on 31 December 2008. There is a plan to build a new reactor, however, this plan is currently subject to assessment on whether it will be profitable. Operation of the new reactor is scheduled for 2039 at the earliest. The new solar park as a new nuclear source has received a positive opinion from the Ministry of the Environment as part of the EIA process. The construction of a nuclear reactor with an installed capacity of up to 1700MWtt should be completed in the near future (although due to Mochovce, the construction of the new reactor has been postponed).

In the Mochovce Power Plant there are currently two units in operation with an output of 470MWh each. Units 3 and 4, with planned installed capacities of 471MWh each, are currently under construction.

E. Upstream

There are no upstream activities in the Slovak Republic.

F. Renewable energy

F.1 Renewable energy

The basic rules on electricity generation from renewable sources are contained primarily in the Renewable Energy Act which fully implements the Renewable Energy Directive.

Under the Renewable Energy Act, measures promoting green electricity vary depending on the type of renewable source and capacity of the production plant. Power plants with a lower installed output are promoted to a greater extent than those with a larger one.

Producers of green electricity are entitled to

- priority connection of their facility for electricity production to the distribution grid;
- priority access to the grid, transmission, distribution and supply of electricity;
- off-take of electricity;
- additional amount as part of the feed-in tariff; and
- the transfer of their liability for imbalances.

Under the Renewable Energy Directive, the Slovak Republic's target for 2020 was to increase the share of electricity generated from renewables to 14% of total energy consumption. This was accomplished, with the Slovak Republic achieving 17%. For 2030 the target is 19.2%.

It must be noted that renewable energy projects are still on hold in Slovak Republic while first auctions are expected to be carried out in 2022. The Ministry of Economy received 120 applications for the construction of new RES. In total, applicants are asking for €57 milion. The Ministry of Economy condirms that 94% of the applications are for solar power plants. If the current applicants are successful, Slovakia couls have 70MWtt of new solar power plants. This will be a step towards reducing Slovakia's dependence on Russian fuels and at the same time fulfilling the national plan. The aforementioned plan envisages an increase of electricity generated from RES by at least 120MWtt by 2026. The majority of this commitment would thus already be covered by the upcoming round of auctions.

F.2 Renewable pre-qualifications

Renewable pre-qualifications for RES auctions are not specified under the law but will be stipulated in the auction conditions.

F.3 Biofuel

The relevant articles of the Renewable Energy Directive and the Biofuel Directive have been transposed into Slovak legislation mainly through the Renewable Energy Act, and in secondary legislation such as the Ordinance of the Ministry of Environment No. 271/2011. These pieces of legislation establish reference values for the share of biofuels in the final consumption of energy and provide for means of promoting the achievement of such reference values.

Producers and importers of motor fuels must sell on the market crude oil based fuels as a blend of the crude oil base and biofuels, currently at a ratio of 5.8% biofuels.

G. Climate change and sustainability

G.1 Climate change initiatives

The Climate Change Package has been transposed into Slovak legislation. Renewable energy was developing rapidly between 2009 and 2012, but now the activity, in particular in solar and wind sectors, is limited.

G.2 Emission trading

Relevant legislative framework

Emission allowance trading is governed by Act No. 414/2012 Coll., on Emission Allowance Trading ("Act") which transposes the New EU ETS Directive into Slovak law. The Act primarily regulates the trading of greenhouse gases ("GHG") emission allowances. The Act stipulates further rights and obligations of the operators of installations and other participants in the emission trading scheme.

Emission trading

An operator of an installation which releases GHG into the atmosphere may only operate under a permit issued by the relevant local environmental authority in accordance with the legal requirements.

Participants in emission trading

GHG emission allowances may be owned and traded by any natural or legal person who has been registered with the Emission Registry and has opened an account. The Emission Registry was established by the European Commission in June 2012 and former accounts in the Slovak National Emission Registry were automatically transferred to it. The national administrator of the Emission Registry for the Slovak Republic is the company ICZ Slovakia a.s.

The applicable law distinguishes between three groups of participants in emission trading:

- obligatory participants;
- voluntary participants; and
- any person who applies for registration in the Emission Registry.

Any operator of an installation must obtain a GHG emissions permit and register with the Emission Registry. The allowances are allocated for a period of eight years starting from 2013 (and for each subsequent eight-year period) pursuant to the EU regulations under an auction mechanism while the free allocation will be gradually decreased.

Any person may voluntarily establish a personal holding account by obtaining the necessary permit. Any account holder may buy and sell allowances.

G.3 Carbon pricing

The prices of carbon allowances are based on prices in the market. Under Act No. 414/2012 Coll. on Emission Allowance Trading, profits from quota auctions is considered as income of the Environmental Fund and 5% will be used to finance a state aid scheme for installations. Therefore, there is a significant risk of carbon leakage due to the pass-through of quota costs into electricity prices.

G.4 Capacity markets

There is no regulation for capacity markets in the Slovak Republic. The Internal Market for Electricity Regulation in electricity applies to the capacity markets.

H. Energy transition

H.1 Overview

The energy transition in the Slovak Republic is progressing very slowly. The whole system is still based on a combination of fossil fuels and nuclear energy. RES are still not a substantive part of the energy mix in Slovak Republic.

H.2 Renewable fuels

Hydrogen

There is no legal definition of hydrogen in the Slovak Republic, but hydrogen is partially mentioned in several Acts. For instance:

- Act No. 309/2009 Coll. for support of RES and high-efficiency cogeneration: According to Art. 2.5 (e), fuel means a substance used for transportations which is hydrogen.
- Act No. 271/2011 Coll. on sustainability criteria and targets for reducing GHG emissions from fuel: According to Art. 9.3 (b), reductions in life cycle GHG emissions of non-biofuel can be achieved by hydrogen.
- Act No. 214/2021 Coll. for support of environmentally friendly road transport vehicles: Art. 3.1 (c) recognises hydrogen as an alternative fuel.

Currently, there is no separate law for supporting the use of hydrogen as a fuel. Nonetheless, the Slovak Government has approved a strategy to increase the use of hydrogen, among other thins, as a fuel.

Ammonia

There are currently no rules regarding the use of ammonia as an alternative energy source.

H.3 Carbon capture and storage

Act No. 258/2011 Coll. on carbon capture and storage has transposed CCS Directive to Slovak Republic's legal system. This act determines conditions for issuing a CCS permission and requesting for carbon storage, and defines conditions for changing, checking and updating a storage permission. The act determines the criteria, procedure for storage and monitoring of repositories and related surface facilities.

Despite Slovak Republic's leglislation enabling carbon capturing and storing activities, there have not been any projects in action.

H.4 Oil and gas platform electrification

There is no legislation in this area.

H.5 Industrial hubs

There is no specific legislation regulating this area. However, this area can generally be covered by other applicable legislations such as those regulating support of investments.

H.6 Smart cities

Since 2013, when European Member States first started to support the idea, the concept of smart cities has become complex and systematic in the Slovak Republic. However, there is no legislation governing smart cities.

Currently, Slovak smart city projects use the model of financing pilot project for the deployment of intelligent solutions in towns in accordance with the de minimis scheme. The capital city, Bratislava and a few other regional centres such as Košice or Nitra have started implementing the smart city concept in Slovak Republic.

I. Environmental, social and governance (ESG)

The Slovak Republic does not have any specific legislations relating to ESG. The National Bank of Slovakia monitors compliance with the requirements set out in the EU Sustainable Finance Disclosure Regulation.

Energy law in Slovenia

Recent developments in the Slovenian energy market

Marko Frantar, local partner, Maks Osojnik, senior associate, Schönherr, Ljubljana

Implementation of the Clean Energy Package

Several important pieces of energy legislation were adopted in 2020-2022 period, including the new Energy Efficiency Act implementing the EU Energy Efficiency Directive (2018/2002), the Act on the Promotion of the Use of Renewable Energy Sources implementing the Renewable Energy Directive (2018/2001) and the Electricity Supply Act implementing the Electricity (Recast) Directive (2019/944). In combination with the recent and future proposed amendments to the construction and spatial planning legislation which, among other things, anticipate an accelerated timeline for permitting procedures, the updated energy legislative framework is also expected to foster investments in the renewables sector.

Coal phase-out strategy

The Integrated National Energy and Climate Plan ("NECP") for 2020 to 2030 (with an outlook for 2040) outlines a goal to decrease the use of coal by at least 30% by 2030, with a view to complete the exit from coal by no later than 2050. In January 2022, the National Strategy on the Phasing Out of Coal and Restructuring of Coal Regions in Accordance with Just Transition Principles was adopted, foreseeing the phase out of coal by the end of 2033. Noting that the production from thermal power plants in recent years accounted for nearly 30% of Slovenia's gross electricity production, it is logical that the coal phase-out discussion is closely related to the issues of energy security and exploration of alternative energy resources. In addition to the development of new renewable energy source ("RES") projects, the discussion also revolves around the increase in nuclear capacities. Various other aspects will also influence the timeline for Slovenia's coal exit, such as the implications of future coal mines closures and thermal power plants on different social and economic indicators linked to employment in the regions that will be the most affected by the transition.

European commission report: low entry barriers to retail power market in Slovenia

In 2021, the European Commission issued a report on European Barriers in Retail Energy Markets, comparing various market conditions in 30 European countries through 16 different parameters. Slovenia ranked second place when comparing electricity markets with the lowest entry barriers, while its gas market ranked eleventh. Although performing above average in comparison to other countries, the report highlights certain areas for improvement. Examples of disincentivising factors include the moderate presence of influence of certain industry actors on regulatory decisions, suboptimal digitalisation and red tape, as well as high price and volume risk in energy procurement.

Dispute over the fracking project in Petišovci

In July 2020, Slovenia was served with a notice of an investment dispute from the UK-based company Ascent Resources. The dispute relates to the development of a hydraulic fracturing project at the Petišovci location in north-eastern Slovenia; the concession rights of which had first been awarded in the early 2000s. In 2019, the Slovenian administrative court upheld an earlier decision by the Slovenian Environment Agency ("ARSO") who ruled that there must be an environmental impact assessment for the Petišovci gas extraction project before Ascent Resources can be issued a separate permit. Ascent Resources argued, among other things, that the ARSO decision conflicts with opinions issued by other Slovenian authorities. In May 2022, Ascent Resources supplemented its notice of dispute, following the adoption of amendments to Slovenia's Mining Act which prohibits the holders of mining rights from carrying out exploration and exploitation of hydrocarbons with the use of any hydraulic stimulation. In August 2022, Ascent Resources initiated arbitration proceedings against Slovenia, administered by the International Centre for Settlement of Investment Disputes, claiming that Slovenia failed to accord fair and equitable treatment, unlawfully expropriated their investment and breached the non-impairment clause under the applicable UK-Slovenia bilateral investment treaty and the Energy Charter Treaty. Ascent Resources have increased its damage assessment from the initial €100 million to over €500 million.

Increase in production capacities

Following years of uncertainty, the concession agreement was concluded in 2020 for the exploitation of water resources on the midstream of the Sava river where construction is planned for a chain of hydro-electric power plants ("HPPs"). The precise number of HPPs is unclear but is expected to be between nine and 12. The HPPs are projected to increase yearly total electricity production by 1,044GWh. The first HPP would tentatively begin operating by 2027, while the other three HPPs would be completed by 2030. Rough calculations suggest a total investment cost of about €350 million for the first three HPPs.

In May 2022, the Slovenian Government ("Government") completed a public interest review regarding the 2,805MW HPP Mokrice project on the basis of the Nature Conservation Act. The decision was issued following a repeated review, after the administrative court annulled the decision from December 2020. The Government (once again) decided that the public interest of producing energy from RES prevails over the public interest of nature conservation. However, the administrative court, acting on petition for an interim injunction filed by NGOs, temporarily suspended the granting of a construction permit in July 2022 until the decision in the administrative dispute became final and binding.

In 2022, HSE completed the construction of a 3MW ground-mounted photovoltaic ("PV") project in Prapretno which is expected to increase to 16MW by 2023. The project was developed on a degraded area on the site of a former thermal power plant. This is the largest single PV project in Slovenia to date. Various other scalable PV projects have been announced for the near future. In July 2022, the Ministry of Infrastructure began preparing a plan to increase the capacity of electricity production from solar energy by 1000MW by 2025.

Regarding Slovenia's nuclear capacities, there have been discussions regarding an expansion of Slovenia's nuclear energy facilities. In July 2021, the Ministry of Infrastructure issued the energy permit for the proposed second reactor at the Krško nuclear power plant, paving the way for requisite administrative procedures and preparation of documentation that will enable the adoption of subsequent final decision on the investment.

Price control and other measures against surging energy prices

In 2022, as a response to soaring energy prices on the global market, the Government adopted a series of measures aimed at mitigating the cost surge. In March 2022, the Government placed a cap on retail and wholesale prices of regular gasoline and diesel. Additionally, fuel suppliers were prohibited from suspending sales operations. The measure was subsequently suspended and adopted in modified form on different occasions. Current price control, regulating retail prices on stations outside highways or express ways, applies until June 2023. Furthermore, in August 2022, the Act Determining Emergency Measures in the Field of Value Added Tax to Mitigate the Energy Commodity Price Rise was adopted, temporarily reducing the VAT rate from 22% to 9.5% for the period from 1 September 2022 to 31 May 2023 for supply of electricity, natural gas, district heating and firewood. Additionally, the Act on Aid for the Economy due to High Increases in Electricity and Natural Gas Prices was adopted, providing state aid in the form of subsidies for the costs of electricity and natural gas by co-financing up to 30% of eligible costs and up to 70% of energy costs for energy-intensive businesses. Several acts also provided one-time-only solidarity benefits to most vulnerable natural persons, eligible legal persons and farmers. Several other relief measures have been adopted or are in the pipeline and are expected to be adopted in the second half of 2022.

Overview of the legal and regulatory framework in Slovenia

A. Electricity

A.1 Industry structure

Nature of the market

The generation and supply of electricity in Slovenia are fully liberalised. Monopolised activities, transmission and distribution are organised as mandatory public services of general economic interest (*obvezna gospodarska javna služba*). They are performed by a fully state-owned Transmission System Operator ("TSO"), ie ELES, d.o.o. ("ELES"), and a Distribution System Operator ("DSO"), ie SODO d.o.o. ("SODO").

SODO leases the distribution infrastructure from and is outsourcing some of its obligations to specific distribution companies. These are ELEKTRO CELJE, d.d, ELEKTRO GORENJSKA, d.d., ELEKTRO LJUBLJANA d.d., ELEKTRO MARIBOR d.d., and ELEKTRO PRIMORSKA d.d. ("Distribution Companies").

Key market players

Participants in the electricity market include producers, traders, suppliers and customers (offtakers), in addition to the DSO, TSO, market operator and power exchange ("PX") operator.

The company BORZEN, operater trga z elektriko, d.o.o. ("Borzen") acts as the Slovenian power market operator and also provides a mandatory public service of general economic interest in Slovenia with the tasks of market supply and demand coordination, operating the clearing process and balancing of the market.

The two largest electricity generators are HSE d.o.o. and GEN energija d.o.o. (together with their affiliated companies).

Regulatory authorities

Electricity generation, trading and consumption are regulated and supervised by the Energy Directorate (*Direktorat za energijo*) of the Ministry of Infrastructure (*Ministrstvo za infrastrukturo*).

The Energy Agency (*Agencija RS za energijo*) is the national energy regulator for electricity and gas markets and as such, is also a member of the European Agency for the Cooperation of Energy Regulators (ie ACER), which participates in the Council of the European Energy Regulators (ie CEER). The Energy Agency has various powers which include giving approval to the rules issued by the power market operator and system operators, setting (network) charges, passing decisions in disputes and appeals, and conducting market supervision. To ensure its independence, the Energy Agency is not financed by the state budget, but rather through compensation obtained from the system operators for the performance of its regulatory tasks/part of the network charges (*omrežnina*).

Legal framework

As of September 2022, the most important pieces of legislation governing the Slovenian electricity market include:

- Energy Efficiency Act,[1] which implements the EU Energy Efficiency Directive (2018/2002);
- Electricity Supply Act,[2] which implements the Electricity (Recast) Directive (2019/944);
- Act on the Promotion of the Use of Renewable Energy Sources,[3] which implements the Renewable Energy Directive (2018/2001);
- Energy Act of 2014 (the former umbrella legislation covering all energy sectors which has been significantly repealed in recent years by means of implementation of sector specific pieces of legislation listed above).[4]

The provisions of the acts listed above are further specified through executive regulations adopted by the Slovenian Government ("Government"), the Energy Agency, the market operator and system operators. Notable examples of secondary legislation include:

- Decree on General Conditions for the Supply and Consumption of Electricity;[5]
- System Operating Instructions for the Electricity Transmission Network;[6]
- System Operating Instructions for the Electricity Distribution System;[7]
- Rules on the Operation of the Electricity Market;[8]
- Act on the Methodology Determining the Regulatory Framework and Network Charge for the Electricity Distribution System;[9] and
- Rules on the Operation of the Electricity Balancing Market.[10]

Implementation of EU electricity directives

Regarding the transmission of electricity, Slovenia has implemented a full ownership unbundling ("FOU") model. ELES was certified as the TSO by the Government following the requirements of the Third Electricity Directive transposed through the Energy Act. At the distribution level, the infrastructure is owned by the Distribution Companies and leased by the DSO.

Several pieces of legislation were adopted in the 2020 – 2022 period, implementing the Clean Energy Package.

A.2 Third party access regime

System operators (ie the TSO and DSO) must enable access to networks based on the regulated third party access principle. In this respect, system operators must ensure that long-term capacity of the networks would enable the granting of reasonable requests for connection and access, as well as provide information required by eligible customers to effectively claim access to the network.

A connection to the network is made based on an application by new users or system operators in accordance with the respective Network Code. Prior to establishing connection to the system (commencing with electricity delivery/consumption from the system) the system operator and the user conclude a connection agreement, stipulating, among other things, the highest connected load or other operational constraint as specified in the consent. Access may only be refused due to lack of capacity or because the increased consumption and/or power delivery would prevent the operator from meeting its statutory obligation of securing services of general interest.

Costs of network upgrades due to connecting a new production unit are borne by the TSO or DSO except in the case of disproportionate costs. In any event, a developer bears the cost of upgrades in case it fails to secure connection within the appropriate time agreed with the TSO or DSO.

A.3 Market design

The generation and supply of electricity in Slovenia are fully liberalised. The Energy Act abolished all existing licensing requirements for the performance of energy-related business activities. Transmission and distribution, each subject to a concession requirement, are monopolised activities in the form of mandatory public services and are carried out by fully state-owned TSO (ie ELES) and DSO (ie SODO), respectively.

For more information on market design, see section A.5.

A.4 Tariff regulation

The use of the distribution and transmission system is subject to network charges, which are borne by the system user. Network charges are one of the sources of funding of justified costs incurred by the electricity system operators. These costs, as well as network charges and other sources of covering these costs, are determined by the Energy Agency in the regulatory framework (*regulativni okvir*) following the Act on the Methodology Determining the Regulatory Framework and Network Charge for Electricity System Operators. The current regulatory framework relates to the period until the end of 2022.

In addition to the network charges for using the distribution and transmission system, users must pay network charges for the cost of excessive reactive power consumption, measured according to excessive reactive power consumption or delivery (ie kVArh) by individual delivery points. They must also pay network charges for the connected load, set by the Energy Agency, in the form of a single lump-sum payment following the connected load (ie kW) at the initial connection to the network and at any increase in the connected load.

A.5 Market entry

The Energy Act abolished all existing licensing requirements for energy related activities. For activities relating to the distribution of closed networks, the Electricity Supply Act requires a formal decision/permit from the Energy Agency, which allows the operator of a closed distribution system to access the transmission system.

The construction of electricity generation facilities will normally be subject to a construction and operation permit requirement; exceptions may apply for small-scale generation units (eg rooftop solar for self-supply if they satisfy specific statutory criteria). Additional permits may apply based on project specifics (eg environmental permits). If the generation capacity of a facility exceeds 10MW, the investor also requires an energy permit issued by the Ministry of Infrastructure.

Under the general Slovenian corporate law regime, foreign companies can generally pursue profitable activities in Slovenia either through the establishment of a branch or through a subsidiary; such established branch or subsidiary must have its corporate seat in Slovenia. There is a degree of ambiguity around the compatibility of this rule as the EU treaties and EU case law freedoms that generally permit the performance of activities on a temporary or sporadic basis will normally not trigger the corporate presence requirement. This must be assessed on a case-by-case basis.

In 2020, Slovenia introduced a foreign direct investment ("FDI") screening regime, requiring foreign investors to obtain approval for acquisitions of at least 10% shareholding or voting rights in Slovenian corporate entities from the Ministry of Economic Development and Technology, if the investment is made in a number of broadly formulated areas which include critical infrastructure (including energy) and the supply of critical inputs (including energy). Unlike many other EU Member States, Slovenia does not exempt EU-based acquirers from the FDI screening regime, and indirect acquisitions or greenfield investments are not expressly carved out from the requirement to notify. The applicability of the FDI regime and, more broadly, all other regulatory requirements, must always be reviewed on a case-by-case basis.

Additional requirements may apply based on project specifics (eg securing appropriate rights to project land or zoning plans in the case of developing energy projects).

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The activities of the TSO and DSO are structured as mandatory public services of general economic interest (*gospodarska javna služba*) and are organised at a state level. System operators must, among other things, transmit/distribute electricity, maintain the networks, ensure a reliable energy supply, provide relevant information, manage the flow of energy in the networks and ensure system services.

Another mandatory public service is the operation of the electricity market which includes the tasks of managing the balancing scheme, operating the balancing market and operating the financial settlement of the market.

On authorisation of the Government, the DSO may transfer certain public service tasks to an appropriate third party. In practice, the DSO transferred some of its obligations to the Distribution Companies (see section A.1).

Smart metering

Under the Electricity Supply Act and the Decree on Measures and Procedures for the Introduction and Interoperability of Advanced Electric Power Metering Systems,[11] the DSO must implement advanced metering systems for all system users. The technical requirements for advanced metering are specified under the Network Code of the DSO and must be met by the end of 2025. For several years, there has been a consistent increase in the use of smart metering devices. This is largely driven by the availability of public funds for co-financing the purchase and installation of smart metering devices for the period until 2022.

Electric vehicles

In order to facilitate the transition to electric vehicles ("EVs"), the Energy Efficiency Act requires the installation of charging points and infrastructure lines for the construction and renovation of residential and non-residential buildings, as well as for existing buildings, rest areas off the public road and for stand-alone car parks. Further measures securing the deployment of EV infrastructure are outlined in the Strategy of traffic development in Slovenia, under which 15% of traffic should be greenhouse gas ("GHG") free by 2030. According to the European Alternative Fuels Observatory ("EAFO") website, as of August 2022, there are around 1,300 public charging stations in Slovenia and more than 5,800 registered EVs.[12] According to the Statistical Office of Slovenia, around 3% of the newly registered vehicles in Slovenia in 2021 were EVs. The purchase of EVs is primarily fuelled by financial incentives made available by the Eco Fund, Slovenian Environmental Public Fund (*Eko sklad slovenski okoljski javni sklad*). Further incentives are provided through tax benefits for EVs available under the Motor Vehicle Tax Act.[13] EVs are exempt from paying a standard annual fee as well as, since the beginning of 2021, being exempt from the payment of motor vehicle tax.

A.7 Cross-border interconnectors

Slovenia has the following operating cross-border interconnections:

- Austria (Maribor – Kainachtal, Podlog – Obersielach);
- Italy (Divača – Redipuglia, Divača – Padriciano); and
- Croatia (Krško – Tumbri, Divača – Melina, Divača – Pehlin, Cirkovce – Žerjavinec).

While there is currently no operating interconnection with Hungary, the construction works on the Cirkovce – Pince transmission line that began in October 2020 are in their final stages. As of August 2022, the construction works are at the stage of acceptance testing and commissioning. The completion of the line is scheduled for 2022.

In accordance with the Rules on the Mode and Conditions of Cross-border Capacities Allocation, cross-border capacities (*čezmejne prenosne zmogljivosti*) are granted based on an auction system. The relevant time periods for which the capacities are acquired can be a day, a week, a month, several months or a year. The interconnections (which since June 2018 have included those on the Slovenian-Croatian border) are part of the multi-regional coupling, where the capacities for the respective border are implicitly allocated through the price coupling of regions ("PCR") solution for the day-ahead markets (see section C.1).

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Oil and oil products are Slovenia's largest energy source, representing a 36% share of Slovenia's energy supply. The domestic oil production is negligible; oil on the Slovenian market predominantly derives from imports.

Gas

Slovenia has limited domestic sources of natural gas and is almost entirely dependent on imports. According to the Energy Agency's Report on the Energy Sector in Slovenia for 2021, 85% of the gas consumed in 2021 was imported from Austria.[14]

Key market players

Natural gas is transmitted by PLINOVODI, Družba za upravljanje s prenosnim sistemom, d.o.o. ("Plinovodi"), the sole gas TSO in Slovenia and owner the transmission and distribution system by several gas DSOs ("gas system operators").

Plinovodi is the sole gas TSO providing the service of general economic interest in Slovenia.

In terms of market shares, key players on the natural gas wholesale market include: Geoplin with a 75.70% share, followed by Petrol, d.d., Ljubljana with a 19.09% market share. On the retail market, key suppliers are Geoplin with a 43.4% market share, GEN-I d.o.o. with a 11.8% share, Javno podjetje Energetika Ljubljana d.o.o. with a 10.8% share, followed by Petrol d.d. Ljubljana with an 9.3% market share.

Regulatory authorities

The authorities in the gas sector in Slovenia are the same as in the electricity sector, ie the Ministry of Infrastructure, the Directorate for Energy and the Energy Agency as the National Regulatory Authority ("NRA") (see section A.1).

Regulated energy activities carried out by natural gas companies comprise services relating to the transmission and distribution of natural gas, which are organised as a public service. The production and supply of natural gas are not subject to specific state regulation.

Legal framework

In December 2021, the oil and gas activities in Slovenia were carved out from the Energy Act and are now regulated in the Gas Supply Act.[15] In terms of subordinate legislation, the most important government regulation is the Decree on the Operation of the Natural Gas Market.[16]

Implementation of EU gas directives

The Third Gas Directive is transposed into Slovenian law through the Gas Supply Act. In accordance with the Gas Supply Act, legal separation of activities is not required for gas system operators if the number of connected customers does not exceed 100,000.

B.2 Third party access regime to gas transportation networks

Both the TSO and the DSO must enable access to the networks based on the third party access principle.

The gas TSO/DSO may refuse access due to lack of capacity or because increased consumption would prevent the operator from meeting its statutory obligation of securing services of general interest. Access may also be refused in the case of serious economic or financial difficulties of companies in the gas sector in relation to 'take or pay' contracts.

If connection is refused due to lack of capacity, the TSO or DSO must make the necessary enhancements to the system upon the request of the interested party if it is economically viable to do so or if the interested party is willing to pay for them.

In relation to entry and exit points of the transmission system, Plinovodi (ie the gas TSO) provides access to the transmission system by concluding transmission contracts at entry and exit points of the transmission system. The technical capacity of individual entry and exit points of the transmission system and their limits are defined and published daily by Plinovodi on its website.[17] Natural gas is transported between entry and exit points considering the technical capacity of the transmission system and in compliance with the New Gas Regulation.

Natural gas is traded in Slovenia via the virtual trading point ("VTP") provided by Plinovodi. Services in the VTP are provided to members only based on a concluded membership contract (payable services).

B.3 LNG terminals and storage facilities

Gas storage and liquified natural gas ("LNG") regasification facilities are governed by the Gas Supply Act. Before commencing operations, the storage system or LNG system owner(s) must designate at least one storage system or LNG system operator. Storage or LNG system operators must operate secure, reliable and efficient natural gas transmission, storage or LNG facilities. They must also provide any other gas TSO, storage system operator, other LNG system operators or gas DSOs with sufficient information to ensure that natural gas is transported in a manner allowing the secure and efficient operation of the interconnected system.

In terms of third-party access to gas storage and LNG facilities, the regime for gas applies *mutatis mutandis* (see section B.2).

B.4 Tariff regulation

Use of the distribution and transmission system is charged by way of network charges, which are borne by the system user and are one of the sources to cover the justified costs incurred by gas system operators. These justified costs, the network charges and other sources to cover these costs are set by the gas system operator in the regulatory framework (*regulativni okvir*), following prior approval of the Energy Agency.

The methodology for setting the regulatory framework is provided under the Act on the Methodology for Determining the Regulatory Framework of the Natural Gas TSO.[18] The current regulatory framework applies until the end of 2024 for both the gas TSO and the gas DSO.

B.5 Market entry

There are no energy licensing requirements under the Gas Supply Act. Market participants must enter the balance scheme.

For activities relating to the distribution of closed networks, the Gas Supply Act imposes a requirement to obtain a formal decision or permit from the Energy Agency, which allows the operator of a closed distribution system to access the transmission system.

Regarding the requirement of establishing a local presence for participation in the local market, FDI screening mechanism and other potential requirements, the same applies to the electricity market (see section A.3).

B.6 Public service obligations and smart metering

Public Service Obligations (PSOs)

The services of the TSO and DSO are organised as public services of general economic interest (*gospodarska javna služba*), performed by the gas TSO and various gas DSOs, respectively. System operators must distribute natural gas, maintain the networks, ensure a reliable energy supply, provide relevant information, manage the flow of energy in the networks and ensure system services.

Smart Metering

Similar to the electricity market, the Energy Efficiency Act establishes that DSOs must ensure smart metering systems for household users. The timeline for the implementation of smart metering is to be determined on the basis of a prior economic evaluation by the Energy Agency, including an assessment of the long-term costs and benefits for both the market and individual customers and what time frame is feasible for their introduction. If the evaluation is positive, the Government shall prescribe measures and a timeline for its introduction. If the evaluation is negative, the Energy Agency must re-examine the circumstances at least every four years. To date, smart metering has not been deployed.

B.7 Cross-border interconnectors

There are three cross-border interconnectors in the Slovenian transmission system, ie Ceršak (Austrian border), Rogatec (Croatian border) and Šempeter (Italian border). The eastern part of the network is the most congested.

A Hungary-Slovenia interconnection (R15/1 Pince – Lendava – Kidričevo) is planned, with a transmission pipeline over 114km long, 73km of which will be in Slovenian territory, and with a planned diameter of 500mm and technical capacity of 38.1GWh per day. In May 2020, the Slovenian Environmental Agency issued an environmental consent for the planned interconnection and in September 2020 the national spatial plan for the construction of a section (Pince – Lendava) of this gas pipeline was adopted with the Governmental Decree for Detailed Plan of National Importance for Pince – Lendava R15/1 Gas Pipeline. The interconnection has been approved as the EU's Project of Common Interest (PCI) as project no. 6.23. Completion of the interconnection is currently expected for the end of 2023.

C. Energy trading

C.1 Electricity trading

The Slovenian electricity market is liberalised. Electricity is traded based on closed agreements (ie the seller and purchaser define a fixed amount of electricity which is traded during a specific time) and open agreements (ie the quantities of electricity are not agreed upon in advance, and payments are made after reading a customer's meter).

Trading on the PX in Slovenia is provided by BSP Energetska Borza d.o.o. ("BSP") owned jointly by Borzen and ELES (50% share each). Wholesale trading can be carried out on the organised exchange or bilaterally. Market participants can also submit transactions outside the PX to be cleared via the BSP clearing system.

The Slovenian organised electricity market is arranged hierarchically into a balance scheme. Any legal or natural person wishing to actively operate on the electricity market must become a member of the balance scheme by either signing a balancing agreement with the market operator or signing a compensation agreement with an existing member of the balance scheme.

Trading over-the-counter and on the exchange

When an electricity trader is a party to a Slovenian balance group, it may trade in Slovenia, either by over-the-counter agreements or through the BSP Energy Exchange. European Federation of Energy Traders ("EFET") standard agreements are widely used on the market.

Trading on the BSP Energy Exchange requires admission as an exchange member or as an affiliate member joining a company group. Market participants are provided with day-ahead and intraday trading on the Slovenian market. Depending on the market segment, standardised and user-defined electricity products can be traded. Market participants can also submit transactions entered into outside the PX to be cleared through the BSP clearing system.

Day-ahead market

The Slovenian day-ahead market is organised as auction trading, where the market participants in the trading phase submit anonymous standardised hourly products on the EuroMarket trading platform. Products are limited by price range from €500/MWh to €3,000/MWh and with a quantitative interval of 1MWh.

The sequences of auction trading on the BSP Energy Exchange are the call phase, freeze phase, price determination phase and after-price determination phase, as follows:

- The call phase runs until 12:00 (noon), however, bids can be entered eight days prior to the trading day. In this phase, orders can be entered, changed or deleted, and the participants only see their own orders.
- The freeze phase runs from 12:00 to 12:05. During the freeze phase, the market supervisor can examine the orders and react if irregularities are detected.
- The price determination phase is between 12:05 and 12:52. Marginal prices calculated at the auction are disclosed to the trading members.
- The after-price determination phase, in which trading members have an overview of the marginal prices and their own deals.

The actual delivery follows on the day after the trading day (day-ahead market).

Intraday market

The intraday market is organised as continuous trading in which market participants submit anonymous standardised and user-defined products in the ComTrader trading platform. Transactions are concluded based on the price/time priority criterion. Submitted orders can range from 1 to 999MW (rounded to 1MWh) and a price between minus (-) €9,999.99/MWh and plus (+) €9,999.99/MWh.

The predefined products are: (i) base (00:00 to 24:00); (ii) peak (8:00 to 20:00); (iii) hourly products; and (iv) 15-minute products. User-defined products are also permitted and are structured as buy or sell orders defined by the user and constituting at least two consecutive predefined products of the same delivery day.

The trading phase takes place one day before the delivery day from 15:00 up until 60 minutes prior to product expiration on the delivery day.

Market participants can also trade on the balancing market, which is embedded in the intraday continuous market in which the TSO (ie ELES) buys and sells electricity for the settlement of imbalances in the electricity system. For trading on the balancing market, the same rules as for the intraday market apply, excluding a prolonged trading phase on the balancing market for one hour until product expiration.

Market coupling

Market coupling on the Slovenian-Italian border is a joint project involving the Italian PX, ie Gestore del Mercato Elettrico, and the BSP PX, a power market operator (ie Borzen), and TSOs (ie TERNA and ELES). Based on NRAs of both countries, market coupling on the Slovenian-Italian borders was set up on 1 January 2011. The Italian-Slovenian market coupling follows a decentralised approach, where each PX manages its own trading system and runs its own matching software, which incorporates a common matching algorithm considering the overall grid model defined by the Italian and Slovenian TSOs for their respective markets.

The Slovenian-Austrian market coupling has been in operation since 22 July 2016: day-ahead capacity for the Slovenian-Austrian border is implicitly allocated through the PCR solution, making this border a part of the multi-regional coupling. Additionally, the Slovenian-Croatian market coupling project was launched on 19 June 2018, by which point the day-ahead market coupling implementations on Slovenian borders was finalised. This established the first implementation of implicit allocation for a Croatian bidding zone.

C.2 Gas trading

Natural gas trading in Slovenia is based on the balance group system, where the supplier of natural gas forms a balancing group and heads this group as the holder of the balance group (*nosilec bilančne skupine*). The balance group comprises other interested market participants, inclusive of their delivery and takeover points.

Under the Decree on the Operation of the Natural Gas Market,[19] natural gas trading is envisioned on the balancing market, organised market and open market, the latter allows market participants to directly conclude contracts; setting, among other things, the price and quantity as well as the takeover point. EFET standard agreements are widely used. All natural gas transactions in Slovenia are performed at the VTP, which is managed by the gas TSO (see section B.2).

D. Nuclear energy

The nuclear programme in Slovenia comprises one operating nuclear power plant, one operating research reactor, one operating central storage facility for radioactive waste to store radioactive waste generated in industry, research and medicine, and a repository for low and intermediate-level radioactive waste. Nuclear energy accounts for the largest share of Slovenia's energy production. In 2021, the proportion of nuclear energy in total energy generation amounted to 37.7% according to the Energy Agency report.

Slovenia has been a member of the OECD Nuclear Energy Agency since 2011 and has one operating nuclear power plant, ie Krško (*Nuklearna elektrarna Krško*) ("NEK").

NEK is owned by NUKLEARNA ELEKTRARNA KRŠKO d.o.o., which has two shareholders with a 50% share each, ie GEN energija d.o.o., owned by the Republic of Slovenia, and HRVATSKA ELEKTROPRIVREDA d.d., a Croatian company. Half of the electricity produced by NEK is transmitted to Croatia.

In 2021, the Slovenian Nuclear Safety Administration (*Uprava Republike Slovenije za jedrsko varnost*) issued a decision permitting the expected operational lifetime of NEK to be extended from the estimated 2023 to 2043 (pending successful periodic safety reviews in 2023 and 2033). Additionally, the Integrated National Energy and Climate Plan for 2020 to 2030 adopted in 2021 (with an outlook to 2040)[20] ("NECP") foresees a feasibility analysis for the construction of a potential second unit of NEK. In July 2021, the Ministry of Infrastructure issued the energy permit for the proposed second unit of NEK, paving the way for requisite administrative procedures and preparation of documentation that will enable the adoption of subsequent final decision on the investment. The decision on NEK2 is currently scheduled to be made by the end of 2027 and will largely depend on the availability and development of other resources.

The relevant legislation and other applicable acts primarily focus on safety and liability for nuclear damage. The core legislation is the Ionising Radiation Protection and Nuclear Safety Act,[21] on which the Resolution on Nuclear and Radiation Safety in the Republic of Slovenia for 2013 to 2023[22] is based, outlining the fundamental safety principles and describing the main radiation and nuclear activities in Slovenia. The Act on Liability for Nuclear Damage[23] also covers the general area of liability for any nuclear damage caused.

The National Programme for Radioactive Waste and Spent Nuclear Fuel Management for 2016 to 2025[24] provides for the steps to be taken to implement the national programme covering all types of radioactive waste and spent fuel.

E. Upstream

Upstream activity in Slovenia is limited. The prospecting, exploration and exploitation of oil and natural gas reserves is mainly governed by the Mining Act.[25] Under the Mining Act, the exploration and production of oil and gas must only be carried out by companies carrying a concession. Projects referring to the prospecting, exploration and production of oil and natural gas reserves may require an environmental consent based on a prior environmental impact assessment.

In April 2022, amendments to the Mining Act, among other things, prohibited holders of mining rights from carrying out exploration and exploitation of hydrocarbons with the use of any hydraulic stimulation.

F. Renewable energy

F.1 Renewable energy

Under the Act on the Promotion of the Use of Renewable Energy Sources, RES are renewable non-fossil energy sources, ie wind, solar, geothermal, wave, tidal, hydropower, biomass, landfill gas, sewage treatment plant gas and biogases. In terms of current aggregate production, the central RES in Slovenia are wood biomass and hydro power, however solar in particular demonstrates potential for exploitation, also on a larger scale.

On the basis of the Decree on Support for Electricity Generated from RES and from High Efficiency Cogeneration,[26] subsidies for the generation of electricity from RES and high-efficiency cogeneration may be granted for units utilising RES that do not exceed a nominal power capacity of 10MW (save for generation units utilising wind power, where the installed capacity cannot exceed 50MW). Incentives are allocated based on a public call for tenders, inviting investors to submit projects for generation units using RES or high-efficiency cogeneration. Financial incentives can be granted in two basic forms, ie (i) a guaranteed purchase (for production units with a nominal power capacity below 500kW), and (ii) an operating premium. Under the guaranteed purchase, the Centre for RES/CHP (*Center za podpore*) at Borzen takes over the electricity from the power plant at a guaranteed price and sells it on the market. Under the operating premium, the producer is entitled to a premium equalling the difference between the full (guaranteed purchase) price and the market price, which is determined *ex ante* on a yearly level, based on plant type, among other things. Producers with power plants having an installed capacity over 500kW can only receive the operating premium. All producers included in the scheme must issue guarantees and transfer guarantees of origin to the Centre for RES/CHP as proof of RES and CHP production.

In addition, the Decree on Self-supply of Electricity from Renewable Energy Sources[27] promotes the use of electricity from RES for self-supply purposes by enabling all self-supplying end-consumers to be (partially) exempted from certain contributions, providing subsidies for the production of electricity from RES and the option to obtain certificates of origin. It also sets out a new calculation of network charges, abolishing the previous net metering regime which was not compliant with Directive 2019/944/EU.

F.2 Renewable pre-qualifications

Beyond eligibility conditions relating to capacity restrictions (see section F.1), specific pre-qualification criteria will typically be determined by the Energy Agency for every public tender (eg final construction permits where applicable, justification of the project based on the applicable guidelines).

F.3 Biofuel

Slovenia has no developed biofuel market, no production or processing capacities of biofuels and depends entirely on imports. Most of the biofuel comes as a mixture with fossil fuels (as permitted by the current standards).

Despite this, Biofuel plays a role in the Integrated NECP from 2020 to 2030, according to which, the use of biofuels will be prioritised for the development, production and use of advanced sustainable biofuels. To reduce the environmental impact of traffic, the legislation provides for a mandatory annual share of biofuels to be provided by distributors of gaseous and liquid fuels for transport. If the percentage of biofuels blended in mineral oil derivatives exceeds 10% by volume, fuel traders will label this at the point of sale. The Decree on the Sustainability Criteria for Biofuels and Greenhouse Gas Emissions[28] ("Sustainability Decree") provides for further criteria for biofuels and transport fuel by which the reduction of GHG emissions in the life cycle of fuels will be achieved.

The Decree on Renewable Energy Sources in Transport[29] also determines the types of biofuels to which the Sustainability Decree will apply, the shares of the annual targets of biofuels that are put on the market for the propulsion of motor vehicles (and how or in what intervals these targets must be satisfied), the obligations of distributors, the announcement of biofuels put on the market and ascertaining the quantity of biofuels for the propulsion of motor vehicles. The prescribed minimum share of RES in transport is set at 10.1% for 2022 and is set to gradually increase up to 11.2% until 2025 and up to 20.8% until 2030. A recent amendment to the aforementioned decree may introduce more flexibility in achieving these targets.

G. Climate change and sustainability

G.1 Climate change initiatives

Environmental protection

Climate and climate change in Slovenia is regulated by the Environmental Protection Act[30] ("EPA") and several other governmental regulations, which can be categorised into:

- environmental protection measures;
- emissions trading and monitoring environmental conditions; and
- environmental duties.

In addition, the applicable law includes the Act on the Ratification of the Framework Convention of the United Nations on Climate Change, and the Act on the Ratification of the Kyoto Protocol to the Framework Convention of the United Nations on Climate Change.

Register of emission allowances

The Slovenian Environment Agency manages the register of emission allowances in Slovenia. The establishment of the register takes into consideration the provisions of the EPA, the EU Emissions Trading System ("ETS") Directive, the Standardised System of Registries Regulation, and also considers Slovenia's obligations arising from the Kyoto Protocol. The Slovenian register has been connected to the register of the United Nations (the International Transaction Log) since 16 October 2008.

G.2 Emission trading

The EPA outlines the basis for the payment of environmental levies in relation to the cause of emissions based on the type, quantity or quality of the emission arising from a particular source. EPA follows the 'polluter pays' principle. The EPA also sets out the framework for trading GHG emission rights (within the framework of the EU ETS) and provides a system for other mechanisms, such as joint implementation (*skupno izvajanje*), a clean development mechanism (*mehanizem čistega razvoja*) and emissions trading (trgovanje z emisijami) established by the Kyoto Protocol.

G.3 Carbon pricing

Under the EPA, the Slovenian government adopted various environmental taxes, including a tax on the pollution of air with carbon dioxide emissions ("CO_2 tax"), which is based on the Decree on environmental tax on carbon dioxide emissions.[31] The tax rate is calculated based on the number of environmental pollution units (equivalent to one tonne of CO_2).

See also section G.2 on Emission trading.

G.4 Capacity markets

There are no specific regulations in Slovenia on capacity markets.

H. Energy transition

H.1 Overview

In February 2020, the Integrated NECP for 2020 to 2030 (with an outlook to 2040)[32] was adopted. The NECP establishes various policies, measures and objectives with a view to Slovenia becoming a carbon neutral country by 2050. Key objectives of the NECP for 2030 include a reduction of GHG emissions by 36%, at least a 35% improvement in energy efficiency and at least a 27% share of RES in gross energy consumption. The NECP sets out a plan where fossil fuel incentives and subsidies will be reduced and later discontinued, and the use of coal will be reduced by 30% by 2030 and phased out by 2050 at the latest. For this reason, a national strategy for coal exit and restructuring coal regions in accordance with the principle of fair transition was adopted in January 2022, foreseeing the phase out of coal and the associated closing date of Unit 6 of the Šoštanj Thermal Power Plant, the largest thermal power plant in the country by the end of 2033. Furthermore, a Spatial Development Strategy of Slovenia 2050 (*Strategija prostorskega razvoja Slovenije 2050*) is scheduled to be adopted by the end of 2022. The strategy is expected to be relevant for future spatial development of energy infrastructure and RES projects in particular.

H.2 Renewable fuels

Hydrogen

A strategy for market development for the establishment of infrastructure for alternative transport fuels was adopted in 2017, which was aimed at implementing Directive 2014/94/EU. On this basis, an Action Plan for alternative transport fuels was adopted in 2019. The Action Plan established objectives and measures for a three-year period and foresees the instalment of four hydrogen charging stations by 2023 and four more in the following years, together with subsidies for hydrogen-powered buses.

Ammonia

Slovenia has no current or planned use of ammonia as a renewable fuel.

H.3 Carbon capture and storage

The EPA bans the geological storage of carbon dioxide within Slovenian territory.

H.4 Oil and gas platform electrification

Slovenia has no oil or gas platforms.

H.5 Industrial hubs

There are no specific energy regulations relating to industrial hubs only.

H.6 Smart cities

In the last few years, various Slovenian cities have been implementing or are planning to implement smart city technologies in the coming years (eg Novo mesto, Ljubljana, Maribor and Kranj). These technologies include monitoring energy consumption, the development of smart street lighting, smart traffic lights, measuring air quality, and so on. Based on the Slovenian Rural Development Program for the period of 2014 to 2020, numerous projects for smart villages have been implemented. These projects aim to strengthen and develop the countryside through using digital technologies and innovation.

I. Environmental, social and governance (ESG)

No ESG specific legislation has been adopted to date. However, investors frequently conduct a pre-transaction review of certain ESG matters, whereby the scope will depend on the target activities and likely risk factors.

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3. Zakon o spodbujanju rabe obnovljivih virov energije – ZSROVE, Official gazette RS no. 121/21, as amended.
4. Energetski zakon – EZ-1, Official gazette RS no. 17/14, as amended.
5. Uredba o splošnih pogojih za dobavo in odjem električne energije, Official Gazette RS no. 117/02, as amended.
6. Sistemska obratovalna navodila za prenosno omrežje električne energije, Official Gazette RS no. 29/16.
7. Sistemska obratovalna navodila za distribucijski sistem električne energije, Official Gazette RS no. 7/21.
8. Pravila za delovanje trga z elektriko, Official Gazette RS no. 74/18, as amended.
9. Akt o metodologiji za določitev regulativnega okvira in metodologiji za obračunavanje omrežnine za elektrooperaterje, Official Gazette RS no. 46/18, as amended.
10. Pravila za izvajanje izravnalnega trga z elektriko, Official Gazette RS no. 97/14, as amended.
11. Uredba o ukrepih in postopkih za uvedbo in povezljivost naprednih merilnih sistemov električne energije, Official Gazette RS no. 79/15.
12. European Alternative Fuels Observatory website, available at www.eafo.eu/alternative-fuels/electricity/charging-infra-stats.
13. Zakon o davku na motorna vozila (ZDMV-1), Offical Gazette RS no. 200/20.
14. Energy Agency's report is available at www.agen-rs.si/porocila-agencije/-/asset_publisher/M2GdU2jRtCxV/content/porocilo-o-stanju-na-podrocju-energetike-v-sloveniji-v-letu-2013?inheritRedirect=false&redirect=https%3A%2F%2Fwww.agen-rs.si%2Fporocila-agencije%3Fp_p_id%3D101_INSTANCE_M2GdU2jRtCxV%26p_p_lifecycle%3D0%26p_p_state%3Dnormal%26p_p_mode%3Dview%26p_p_col_id%3Dcolumn-1%26p_p_col_count%3D1.
15. Zakon o oskrbi s plini, Official Gazette RS no. 204/21.
16. Uredba o delovanju trga z zemeljskim plinom, Official Gazette RS no. 61/16, as amended.
17. See www.plinovodi.si/en.
18. Akt o metodologiji za določitev regulativnega okvira operaterja sistema zemeljskega plina; Official Gazette RS no. 21/18, as amended.
19. Uredba o delovanju trga z zemeljskim plinom; Official Gazette RS no. 61/16, as amended.
20. Celoviti nacionalni energetski in podnebni načrt za obdobje do 2030 (NEPN).
21. Zakon o varstvu pred ionizirajočimi sevanji in jedrski varnosti, Official Gazette RS no. 76/17, as amended.
22. Resolucija o jedrski in sevalni varnosti v Republiki Sloveniji za obdobje 2013-2023 – ReNRS13–23.
23. Zakon o odgovornosti za jedrsko škodo; Official Gazette RS no. 77/10.
24. Nacionalni program ravnanja z radioaktivnimi odpadki in izrabljenim gorivom za obdobje 2016-2025.
25. Zakon o rudarstvu, Official Gazette RS no. 14/44, as amended.
26. Uredba o podporah elektriki, proizvedeni iz obnovljivih virov energije in v soproizvodnji toplote in elektrike z visokim izkoristkom, Official Gazette RS no.26/22.
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28. Uredba o trajnostnih merilih za biogoriva in emisiji toplogrednih plinov goriv; Official Gazette RS no. 44/21, as amended.
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Energy law in Spain

Recent developments in the Spanish energy sector

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At the beginning of 2020, a Spanish Government ("Government") was formed by the political parties Partido Socialista and Podemos which took office following a period of political uncertainty in 2019, and after the holding of two general elections. In the new Cabinet, the Head of the Ministry for Ecological Transition and the Demographic Challenge ("MITERD"), who is competent in all energy related matters, is Teresa Ribera, who has held this position since June 2018.

Throughout 2020, 2021 and the first half of 2022, the main regulatory developments in the energy field have been in the areas of electricity, natural gas, and the energy transition.

Electricity sector

In the last three years, there has been great regulatory activity in the electricity sector, highlighted by five fundamental milestones: i) the approval of Royal Decree-Law 23/2020, of 23 June, which establishes expiration periods for access permits and connection of electricity generation facilities granted since 2014, and for those that may be granted thereafter; ii) the approval of a new remuneration framework for renewable generation facilities; iii) the approval of a new regulatory framework for access and connection to the distribution and transportation networks of electricity generation facilities; iv) the approval of different measures to curb the increase of electricity prices (gas claw-back mechanism and the "Iberian exception"); and v) the modification of the financing scheme for the social bonus.

Approval of Royal Decree-Law 23/2020 of 23 June

On 24 June 2020, Spain's Official State Journal (*Boletín Oficial del Estado*) published Royal Decree-Law 23/2020, of 23 June, which approves measures in relation to energy and other areas to stimulate economic recovery ("RDL 23/2020"). RDL 23/2020 contains measures that affect a number of different sectors, but it primarily contains provisions for the electricity sector, with a particular focus on the regulations that govern renewable energy generation facilities.

One of the most relevant provisions of RDL 23/2020 is the introduction of expiry dates for grid access permits awarded since 27 December 2013.

Grid access and connection permits allow an operator to connect to the transmission or distribution grid and, in the case of generation facilities, to feed into the grid the energy they generate. Obtaining a permit is essential for a facility to obtain administrative authorisation.

Until the approval of RDL 23/2020, only grid access and connection permits awarded before 27 December 2013[1] were at risk of expiry. Under the eighth transitional provision of the Electricity Sector Act 24/2013, of 26 December 2013, as implemented and amended ("ESA"), grid access and connection permits for facilities that had not obtained an operating permit before 21 August 2020 would expire.

However, grid access and connection permits awarded after that date were not, in practice, subject to expiry. As such, RDL 23/2020 regulates the expiry of access permits awarded before ESA entered into force as well as all of those awarded thereafter. Expiry is linked to a number of administrative milestones and, therefore, a grid access permit expires if the established deadlines are not met, which in turn triggers the expiry of the associated connection permit.

The RDL 23/2020 distinguished between three categories of grid access permits on the basis of the date on which they were awarded, and five milestones. The deadlines to achieve these milestones were later extended by means of Royal Decree-Law 29/2021, of 21 December. Specifically, these are the applicable milestones and respective deadlines:

	GRID ACCESS PERMITS AWARDED BETWEEN 28 DECEMBER 2013 AND 31 DECEMBER 2017	GRID ACCESS PERMITS AWARDED BETWEEN 1 JANUARY 2018 AND 24 JUNE 2020	GRID ACCESS PERMITS AWARDED FROM 25 JUNE 2020 ONWARD
Admission of the application for the prior administrative authorisation ("PAA")	3 months (expires 24 September 2020)	6 months[2] (expires 24 December 2020)	6 months after the award of the permit
Obtaining a favourable environmental impact assessment ("EIA")	27 months (expires 24 September 2022)	31 months (expires 24 January 2023)	31 months after the award of the permit

	GRID ACCESS PERMITS AWARDED BETWEEN 28 DECEMBER 2013 AND 31 DECEMBER 2017	GRID ACCESS PERMITS AWARDED BETWEEN 1 JANUARY 2018 AND 24 JUNE 2020	GRID ACCESS PERMITS AWARDED FROM 25 JUNE 2020 ONWARD
Obtaining PAA	30 months (expires 24 December 20232)	34 months (expires 24 April 2023)	34 months after the award of the permit
Obtaining a construction permit ("CP")	33 months (expires 24 March 2023)	37 months (expires 24 July 2023)	37 months after the award of the permit
Obtaining a definitive operating permit ("DOP")	5 years (expires 24 June 2025)	5 years (expires 24 June 2025)	5 years after the award of the permit

In relation to those milestones:

- Evidence must be provided to the corresponding grid manager that each deadline has been met; if this is not done in a timely manner and in the proper form, RDL 23/2020 indicates that the access permit, and therefore the connection permit, will expire 'automatically'. If the facility is exempt from a milestone, evidence of that fact must be provided by means of a document in which the authority responsible for granting the respective authorisation or environmental impact statement ('EIS') states the same.
- If expiry occurs, the authority responsible for awarding the authorisations will enforce the guarantees provided to apply for access. As an exception, those guarantees will not be enforced if an unfavourable EIS is issued for reasons not attributable to the developer.

Additionally, RDL 23/2020, among other things:

- amends the ESA in order to partially transpose Directives (EU) 2019/944 and 2018/2001, including provisions (albeit pending regulatory implementation) on three new concepts: storage, demand-side aggregation and renewable energy communities;
- regulates (although, subject to regulatory implementation, recently included in the new legal framework for access and connection permits) the optimisation of access for renewable energy generation through hybridisation; and
- includes a number of procedural provisions to simplify certain formalities and eliminate the need to obtain administrative authorisation for certain modifications to generation facilities.

Approval of a new remunerative regime for new renewable generation facilities

RDL 23/2020 amended the ESA to include a new Article 14.7 bis that permits the Government to set up, by means of regulatory provisions, a new remunerative framework applicable to new renewable energy generation facilities. This new Article was implemented by Royal Decree 960/2020, of 3 November ("RD 960/2020"), which regulates the economic regime of renewable energies for electricity (*régimen económico de energías renovables*) ("REER").

This new REER, is an alternative to market compensation. Installations that have been granted the REER cannot enter into physical power purchase agreements (PPAs) and, although they must participate in the daily and intraday market, they receive remuneration allocated to them under the REER for the energy traded.

The REER will, by default and for each respective facility, have a term equal to the supply term established at each respective auction (which should, generally, range between 10 and 15 years, but which may exceptionally reach 20 years). However, the REER will also come to an end if, before the expiry of the relevant term: (i) if the awardee facility supplies the maximum volume of power awarded; or (ii) if that facility withdraws from the REER, which it may do without penalty once the minimum volume of energy has been supplied (otherwise, if that minimum volume is not achieved, a penalty will be imposed).

The REER will be financed and paid for by the electricity wholesale market. OMIE will settle the difference, which may be positive or negative, between the spot and intraday market prices and the price established for each facility that has been awarded the REER. If the spot price is higher than the awarded price, the facility will only receive the award price (as applicable, adjusted with the market incentive, if one has been defined) and its difference with the spot price will be distributed by OMIE, as income, among national energy buyers. If the spot price is lower, the owner of the facility receiving the REER will be entitled to receive the difference, which will be settled as a market cost payable by energy buyers in that same proportion.

The main characteristics of this new REER are:

- Eligible facilities: Under RD 960/2020, only renewable energy facilities will be eligible to receive the REER, which also requires that those facilities are the result of a "*new investment made after the corresponding auction has been held*", whether because the facility is totally new or because an enlargement or modification has been made to an existing facility (although, in the latter case, it will only apply to the energy produced by the enlargement or modification). However, it is expressly established that the facilities signed up to the REER may use more than one technology, which must be renewable (therefore includes hybrid facilities), including storage facilities.
- New auction mechanism: Generally, the REER will be awarded at auction. However, as an exception, RD 960/2020 establishes that facilities with an installed power capacity of less than 5MW and demonstration projects are eligible to receive the REER directly (without the need to take part in auctions).

  The details of the auction mechanism will be defined in a MITERD Order: this Order may define, among other things, the technologies, terms and conditions and guarantees that must be provided to take part in the auction, the product being auctioned, as well as the parameters and other elements of which the REER is composed.

Auctions may be technology neutral or technology specific, on the basis of criteria which includes, among other things: their technical characteristics, scale, degree of dispatchability, localisation criteria and technological maturity. Tenderers must submit sealed bids in terms of €/MWh (to two decimal places). Auctioned energy will then be awarded on a 'pay as bid' basis.

An auction will award a certain power or capacity or energy, depending on the product up for auction, to each tenderer, as well as a price, which will match the tenderer's financial bid.

The auction mechanism was regulated in Order TED/1161/2020, of 4 December 2020. This Order also established the indicative auction calendar for the period 2020-2025.

So far, four auctions have been held, on 26 January 2021, 19 October 2021, 25 October 2022 and 22 November 2022

Approval of a new legal framework for access and connection permits

The legal framework for the access and connection of electricity generation facilities in Spain has recently been modified. This new legal framework is essentially contained in two regulations, ie, RD 1183/2020, of 29 December, and Circular 1/2021, of 20 January.

The new framework provides a standard procedure for granting grid access and some exceptions in which access is granted by means of a tender.

Under the standard procedure, access and connection permits are granted in chronological order. Where two or more applications are submitted for the same connection point, grid access and connection are generally granted in chronological order according to the time and date on which each application was admitted for processing. If no rectification is requested, this will be the time and date on which the application was submitted. If a rectification is requested, this will be the time and date on which all the documentation and information required was correctly submitted. In the case of generation facilities, if the time and date on which two applications have been admitted to processing is the same, the order of preference will be determined by the time and date on which the confirmation of having posted the guarantee had been sent to the body responsible for authorising the facility (in the case of joint applications covering several facilities, the latest of the dates on which such confirmations were sent).

In this standard procedure, a prior proposal must be notified to the applicant within 60 days of it having submitted its application for connection to the transmission network, and within ten, thirty or forty days in the case of generation facilities connected to the distribution network, depending respectively on whether the voltage is lower than 1kV, 36kV or equal to or higher than 36kV. These time periods are doubled when an acceptability report needs to be requested from the manager of an upstream transmission or distribution network.

Within 30 days, the applicant must accept the prior proposal on its terms or request a review of specific aspects. If it fails to do either, or if it requests a review and does not accept the network manager's response within the specific term, the application will be understood to have been denied and the guarantee returned.

The RD 1183/2020 establishes that, as an exception, tenders may be organised to grant grid access and connection at certain nodes of the transmission network to new renewable energy generation facilities and storage facilities by means of an Order issued by the head of MITERD, subject to a prior report issued by the Government's Delegated Commission for Economic Affairs. The Secretary of State for Energy has made use of this option on four occasions, through the resolutions of 29 June and 20 August 2021, as well as 28 February and 3 August 2022, by which it ordered the holding of tenders at 289 nodes.

In principle, these tenders must be called within ten months of the Ministry's decision to hold them. This period was extended to twelve months by Royal Decree-Law 6/2022 of 29 March ("RDL 6/2022") and, subsequently, Royal Decree-Law 11/2022 of 25 June stated that, even if this period elapses without the tender being called, the reserved capacity will not be released until the Secretary of State for Energy issues a Resolution stating this. As of the end of January 2023, no tender had yet been called, but the first tender was expected to take place soon, as the draft Order regulating it had already been submitted for public hearing.

The RD 1183/2020 establishes that the criteria for awarding the tenders shall be: (i) chronological, giving priority to projects that start feeding energy into the network earlier; (ii) technological, giving priority to projects that maximise the volume of renewable energy that may be fed into the network; (iii) where appropriate, technical, giving priority to technologies in a research, development and innovation phase, although each tender cannot reserve more than 30MW for such technologies; (iv) where appropriate, environmental and socio-economical, taking into account the level of employment and investment that the developer plans to carry out in the area where the node is located, and evaluating the foreseeable environmental impact of the project; and (v) as appropriate, criteria that contribute to the economic activation in demographically challenged areas affected by the location of the projected facility.

There is a second exception to the standard procedure and, therefore, to the principle of awarding capacity in chronological order of applications. This exception refers to 'fair transition nodes',[4] where capacity will be released due to the closure of coal-fired and thermonuclear power stations.

In these nodes, the head of the MITERD may, subject to a prior report issued by the Government's Delegated Commission for Economic Affairs, establish specific procedures and requirements to award all or part of the capacity released at the node.

In November 2021, the first tender was called in a fair transition node (the "Mudejar" node), by means of Order TED/1182/2021. This tender was resolved by the MITERD by means of Order TED/1146/2022 on 21 November 2022.

Measures taken to curb electricity prices: gas claw-back mechanism and "Iberian exception"

As in many other countries, electricity prices have been experiencing a sharp increase since the spring of 2021, as a consequence of the soaring prices of natural gas (and in particular due to the fact that gas fired plants are the ones that set the marginal price in many hours of the day).

Throughout 2021 and 2022, this increase in gas prices has led to the adoption of various measures aimed at curbing this price escalation. These measures include the following:

- Gas claw-back mechanism

Royal Decree-Law 17/2021, of 14 September, created the so-called gas claw back mechanism. Under this mechanism, certain non-emitting and infra-marginal plants located on the Spanish mainland must pay the electricity system for each MWh produced, an amount proportional to the difference between the average monthly price of gas on the organised market and a reference value of €20/MWh, which would be settled monthly. It must be noted that after the entry into force of the so-called "Iberian exception" (see sub-paragraph (ii) below) this payment is calculated based on the difference between the value of €20/MWh and the so-called "reference price of natural gas" (PGRN) which, until December 2022, will have a value of €40/MWh.

This mechanism does not apply: (i) to plants whose installed capacity does not exceed 10MW; (ii) to plants entitled to a remuneration scheme; (iii) to energy for which a fixed-price forward contracting instrument is in place.

Initially, this mechanism was only to apply until 31 March 2022; however, it has been recently extended until 31 December 2023.

- Gas price cap mechanism (Iberian exception).

Royal Decree-Law 10/2022, of 13 May ("RDL 10/2022"), created a gas price cap mechanism (the so called "Iberian exception").

Under RDL 10/2022 the mechanism is due to be in effect until 31 May 2023. However, RDL 10/2022 authorises the Government, by means of a decision of the Council of Ministers and with the approval of the Portuguese Government, to suspend, either temporarily or definitively, the application of the mechanism "when this is justified due to exceptional market circumstances or on grounds of general interest".

In essence, the mechanism imposes obligations on certain plants emitting carbon dioxide ("CO_2") to place offers on the Iberian spot market, discounting the so called "adjustment's" unit value. The "adjustment" is proportional in value to the difference between the average spot price of natural gas on MIBGAS and a capped value called the "reference price of natural gas". Specifically, the adjustment is equal to the sum of dividing the above difference by 0.55, which is the same as multiplying it by 1.81).

The "reference price of natural gas" that will be used to calculate the adjustment will be €40/MWh during the mechanism's first six months of application, which will be subsequently increased by €5 per month as from the seventh month of application (thus, if the mechanism were to apply until May 2023, it could reach €70/MWh),

As a result of the application of this "adjustment" to their bids, the wholesale market price is reduced (and, therefore, also the remuneration received by the infra-marginal non-emitting plants).

The CO_2-emitting plants obliged to discount the adjustment in their bids are then compensated for its amount. This compensation is borne by the energy demand as a whole (traders and direct consumers in the market).

Modification of the financing scheme for the social bonus

The social bonus is a discount on the price of electricity applied by the so-called reference suppliers to certain vulnerable consumers. These reference marketers are then compensated for the cost of this discount through a financing system which has taken various forms over the years.

The Supreme Court, in a ruling of 31 January 2022 (followed by other subsequent rulings), annulled the financing system of the social bonus introduced by Royal Decree 7/2016, of 23 December (which placed this obligation on the suppliers). As a result, the Government, by means of RDL 6/2022 (as subsequently amended by RDL 10/2022), approved a new financing system that placed this obligation on all electricity activities (transmission, distribution, generation, and supply), as well as on direct consumers in the market.

The obligation translates into the payment of an amount calculated on the basis of unit values which will be determined each year by the National Commission for Markets and Competition in accordance with the relevant criteria determined by RDL 6/2022.

Natural gas

In early 2019, the regulatory powers to determine the remuneration methodology for the activities of distribution, transportation and regasification of natural gas were held by the National Markets and Competition Commission ("CNMC"). This resulted in CNMC's approval of Circular 9/2019, of 12 December, which establishes the methodology to determine the remuneration of natural gas transportation facilities and liquefied natural gas (LNG) plants, as well as Circular 4/2020, of 31 March, which establishes the methodology for remunerating natural gas distribution ("Circular 4/2020").

Approval of Circular 4/2020, of 31 March, which establishes the methodology for remunerating natural gas distribution

On 3 April 2020, Spain's Official State Journal (*Boletín Oficial del Estado*) published Circular 4/2020, of 31 March, of the National Markets and Competition Commission, which established the methodology for remunerating natural gas distribution during the second regulatory period.[5] This replaced the previous framework which applied up to that date,[6] on the approval of urgent measures for growth, competitiveness, and efficiency ("Ley 18/2014"). The Circular, as initially proposed by the CNMC,[7] substantially modified the methodology for remunerating natural gas distribution established by Law 18/2014. The remuneration structure contained in Law 18/2014 was an activity-based remuneration model which had been used to remunerate natural gas distribution since 2002. However, the first version of the Circular established a mixed model, in which: (i) facilities brought into service up to 2020 would be subject to an asset-based remunerative model; and (ii) assets brought into service from 2021 onwards would be subject to an activity-based market development remunerative model,[8] albeit with a number of modifications.

The first version of the Circular elicited a huge sector response because, although the CNMC anticipated that the methodology would mean an average reduction of 17.8% in the remuneration of natural gas distribution, the impact was in fact very uneven (and potentially far higher) for different companies depending on the age (and, therefore, degree of depreciation) of their assets.

As a result, on 3 December 2019 the CNMC restarted the process and sent a new Circular for public consultation in which it dropped its plans to change the remunerative methodology used, retaining the remunerative structure used since 2002,[9] albeit subject to certain modifications and adjustments. The Circular which was ultimately approved essentially retained those terms. Indeed, Circular 4/2020 established a similar remuneration structure to, and is essentially a continuation of, the one contained in Annex X of Law 18/2014. Some specific features of the Circular are as follows:

- The Circular established a base remuneration, constituting market remuneration for distribution from 31 December 2020 (*Retribución base*) ("RDE"). That base remuneration RDE is calculated on the basis of the distribution remuneration for 2020 calculated according to the methodology established in Law 18/2014, minus what is known as a distribution remunerative adjustment ("AAD").[10] The AAD component includes an adjustment (one of the new elements included in the Circular) to the remuneration for the distribution activity performed in 2000.[11] However, the adjustment is applied gradually by recognising a transitional distribution remuneration,[12] decreasing over time, between 2021-2025.
- The Circular establishes a market development component,[13] which remunerates gas distribution on the basis of market development after 1 January 2021 according to a parametric formula similar (albeit with a number of minor modifications) to the one established in Law 18/2014.
- The Circular contains a new incentive, or penalty, depending on the case to cover gas leakages.[14] This incentive (or penalty) is calculated according to the provisions of Article 14 of Order IET/2446/2013, of 27 December, which established the tariffs and charges associated with third party access to gas facilities and the remuneration of regulated activities.

Circular 4/2020 also contains two entirely new features:

- It includes an adjustment which applies to companies that supply connected products or services to third parties for which they use installations and resources remunerated on the basis of the remunerative structure. Defining the methodology for determining that adjustment for each connected product or service is deferred for a later CNMC Resolution which is still pending.
- It establishes, with effect from 2024, a financial prudence penalty, which can reach a maximum of 1% of the company's overall remuneration and is linked to the recommended ratios and values for assessing companies' indebtedness and economic and financial capacity.[15]

The Notes to the Circular 4/2020 point out that the average remuneration for distribution in the regulatory period 2021-2026 will be reduced from €1.42 billion, calculated as per the methodology under Law 18/2014, to €1.283 billion, calculated using the new methodology. This will result in an average reduction of 9.6% in remuneration for distribution. In respect of the final year of the regulatory period (ie, 2026), the Notes offer a new overall remuneration for distribution of €1.181 billion, as opposed to the €1.42 billion that would have applied using the methodology contained in Law 18/2014.

However, it should be noted that the above reduction is primarily due to the adjustments made to the remuneration for distribution in place in 2000, therefore, irrespective of what the average reduction might be, its impact on the different operators will be greater or smaller depending on the greater or smaller weight of that "legacy" business in the operator's current business.

Approval of the integrated national energy and climate Plan 2021-2030 and of the climate change and energy transition law

In 2021, Law 7/2021, of May 20, which concerns climate change and energy transition ("Law 7/2021"), and the Integrated National Energy and Climate Plan 2021-2030 ("PNIEC") were both approved.

These are the two main documents in which the Government has set out the guidelines for its energy policy for the coming years, under the principle of decarbonisation and electrification of the economy.

The PNIEC was approved by Agreement of the Council of Ministers of 16 March 2021 and published in the Official State Gazette of 31 March. Additionally, on 21 May, the Official State Gazette published Law 7/2021, following its approval by the Spanish Congress. Law 7/2021 entered into force on the following day.

Law 7/2021 establishes national targets for 2030 and 2050 for renewable energy, energy efficiency and the reduction of greenhouse gas ("GHG") emissions. Specifically:

a. It set the following targets for 2030:
    - 23% reduction of GHG emissions compared to 1990;
    - 42% of final energy consumption from renewable energy sources ("RES");
    - 74% of electricity generation from RES; and
    - 39.5% reduction in the consumption of primary energy in respect of the baseline under EU regulations.
b. It also sets the following targets for 2050:
    - Spain should achieve climate neutrality; and
    - 100% electricity generation from RES.

These targets are more ambitious than those established for the EU overall in the different instruments of the Energy and Climate Package.[16] Furthermore, the above provisions do not preclude the Council of Ministers from being able to review those objectives upward; the plan is that the first review will take place in 2023.[17]

Among other things, Law 7/2021 includes:

- restrictive provisions related to the exploration, research and exploitation of hydrocarbons, logically in line with the overriding goal of decarbonising the economy;
- a mandate for the Government to foster the penetration of renewable gases (including biogas, bio-methane and hydrogen) and biofuels, with special emphasis on advanced biofuels and other non-biological renewable fuels;
- restrictive measures in relation to exploration, research and

exploitation of radioactive minerals, and establishes that, from the date on which the Law enters into effect, no new applications for radioactive facilities in the nuclear fuel cycle aimed at processing those radioactive minerals will be accepted;

- measures aimed at promoting sustainable mobility and the use of electric vehicles. In particular, a target has been established for 2050 to have a fleet of passenger cars and light commercial vehicles without direct CO_2 emissions; to that end, it has been indicated that by 2040 at the latest all new passenger cars and light commercial vehicles, excluding those registered as historic vehicles, not used for commercial activities, must have 0gCO_2/km emissions; and
- within 12 months of the Law entering into effect, the Government and the CNMC, each within the scope of their respective competencies, must submit a proposal to reform the regulations governing the electricity sector, to encompass: (i) the participation of individual consumers in the energy markets, including response to demand via independent aggregation; (ii) investments in variable and flexible generation of renewable energy, as well as distributed generation; (iii) energy storage; (iv) the use of electricity networks and flexibility for the management of these and the local energy markets; (v) access by energy consumers to their data; and (vi) innovation in energy.

Endnotes

1. The date on which the Electricity Sector Act 24/2013, of 26 December 2013, as implemented and amended (ie the ESA) entered into force.
2. The deadlines in the first two columns are calculated from the date on which RDL 23/2020 entered into force (ie, 25 June 2020), in accordance with the provisions of its Article 1.
3. OMIE is the nominated electricity market operator (NEMO) for managing the Iberian Peninsula's day-ahead and intraday electricity markets.
4. Listed in the Annex to RDL 23/2020.
5. Beginning on 1 January 2021 and ending on 31 December 2026.
6. As established in Annex X of Law 18/2014, of 15 October.
7. Submitted to public consultation on 5 July 2019.
8. Applying the parametric formula defined in Law 18/2014.
9. Under Annex X of Law 18/2014.
10. *Ajuste retributivo de la actividad de distribución*, or "AAD".
11. The remuneration corresponding to the supply points existing in 2000 and their consumption that year significantly exceeds the remuneration currently applied for new supply points and new demand, which is not economically justifiable. Consequently, the economic adjustment is made to remunerate the supply points and demand for natural gas existing in the year 2000 with, at the most, the remuneration currently established in the remuneration for market development ("RDM") for new supply and demand points. In turn, the RDM is linked to the new supply points to be established as from 2021, and is determined according to certain parameters.
12. *Retribución transitoria de distribución*, or ''RTD'".
13. *Retribución por desarrollo de mercado*, or "RDM".
14. *Incentivo por la liquidación de las mermas de gas*, or "IM".
15. Established by the CNMC's Communication 1/2019, of 23 October, of the National Markets and Competition Commission, which defines the ratios for evaluating the level of indebtedness and economic and financial capacity of companies that perform regulated activities.
16. This was already the case in the bill, as pointed out by the Council of State in its report, but even more so in the final version of Law 7/2021, which aligns those targets to those established in the PNIEC.
17. This provision complies with the contents of Article 3.1 of Directive 2018/2001, according to which the Commission shall assess the overall 32% target *"with a view to submitting a legislative proposal by 2023 to increase it where there are further substantial costs reductions in the production of renewable energy, where needed to meet the Union's international commitments for decarbonisation, or where a significant decrease in energy consumption in the Union justifies such an increase"*.

Overview of the legal and regulatory framework in Spain

A. Electricity

A.1 Industry structure

Nature of the market

The electricity market in Spain is divided into regulated and unregulated activities. The economic and technical management of the system, transmission and distribution are considered to be regulated activities, which means that the applicable operation and remuneration regimes are regulated by the Spanish Government ("Government") and the Spanish Regulatory Authority. From a legal standpoint, transmission and distribution activities are considered to be natural monopolies; however, operators must allow third parties to access their networks. Other activities are undertaken within a framework of free competition on the terms set out in specific sector legislation.

Key market players

The key market players in the electricity sector are:

- generators: individuals or business entities generating energy either for their own consumption or for a third party's consumption;
- distributors: business entities whose function is to distribute electrical power and to construct, maintain and operate distribution installations;
- suppliers: business entities that have access to the transmission and distribution networks and acquire electrical power to sell it on to consumers or other system agents or to carry out international trade operations;
- direct consumers: individuals or business entities that purchase electrical power in the market for their own consumption or for the provision of energy recharging services for vehicles;
- reference suppliers (previously called last resort suppliers): business entities that have access to the transmission and distribution networks and offer electrical power to consumers subject to the voluntary price for small consumers ("PVPC") (previously called last resort tariffs), which is the maximum reference price at which most domestic consumers will purchase their electricity;
- small consumers (previously called last resort consumers): low voltage electricity consumers whose energy usage is lower than or equal to 10kW;
- vulnerable consumers: domestic consumers who are classified as vulnerable because of their social and economic situation;
- system operator (ie *Red Eléctrica de España* or "REE"): the manager of the transmission grid which also acts as the sole and independent transmission system operator ("TSO") on an exclusive basis; and
- market operator (*Operador del Mercado Ibérico de la Energía* ("OMIE")).

The main players in the electric sector are Endesa S.A., Iberdrola S.A., Naturgy Energy Group S.A., EDP Energías de Portugal S.A and Acciona S.A.

Regulatory authorities

The main regulatory bodies responsible for the control of the electricity system are the Spanish Ministry for Ecological Transition and the Demographic Challenge (*Ministerio para la Transición Ecológica y el Reto Demográfico*) ("MITERD"), the administrative bodies of the various autonomous regions, the National Markets and the Competition Commission (*Comisión Nacional de los Mercados y de la Competencia*) ("CNMC") created under Act 3/2013, of 4 June 2013 ("Act 3/2013"), which is the Spanish Regulatory Authority. The aim of Act 3/2013 is to integrate and link the functions related to the proper functioning of the markets and the supervised sectors of, among others, the National Energy Commission, the Competition National Commission, and the Railway Regulation Committee.

The functions of the CNMC in the electricity sector were notably expanded, to adapt to the requirements of European Union ("EU") Directives, by Royal Decree-Law 1/2019, of 11 January.

Legal framework

The Spanish energy sector is governed primarily by the Electricity Sector Act 24/2013, of 26 December 2013, as implemented and amended ("ESA"). The ESA is governed by the principle of economic and financial sustainability of the electricity system. This means that any regulatory measure that causes an increase in costs or a reduction in income for the electricity system should incorporate an equivalent reduction of other cost items or an equivalent increase in income that ensures the equilibrium of the system. The possibility of new deficits accumulating, as has occurred in the past, is therefore reduced. Of the elements introduced by the ESA, one of the most noteworthy is the principle of 'reasonable rate of return', according to which participants in the electricity market should make a return which is at least equal to the return before taxes of the average yield of ten-year Government bonds on the secondary market, plus a differential. This reasonable rate of return applies to the following activities: transmission, distribution, and generation of electricity from renewable energy sources ("RES"), cogeneration and waste, and generation in non-peninsular electrical systems with an additional remuneration regime. In addition, the remuneration system of these activities is reviewed every six years.

At present, the competence to determine the methodology for calculating the remuneration and the remuneration rate for network activities (transmission and distribution) is awarded to the CNMC. With regard to renewable, cogeneration, waste-to-energy and non-peninsular generation facilities, this competence is awarded to the Government.

The ESA establishes measures to encourage consumers' choice of supplier, to streamline the process of changing supplier and to simplify a customer's electricity bill. It also retains the 'social bonus' for vulnerable consumers and creates the PVPC.

The 'social bonus' is a form of supply applicable to vulnerable consumers (the tariffs consist of the PVPC with a 25% discount, which has been temporarily increased to 65% until 31 December 2023) or severely vulnerable consumers (the tariffs consist of the PVPC with a 40% discount, which has been temporarily increased to 80% until 31 December 2023).

Implementation of EU electricity directives

The First Electricity Directive was transposed into Spanish legislation through the ESA. The Second Electricity Directive was fully implemented by Act 17/2007, of 2 July 2007 ("Act 17/2007").

The Royal Decree-Law 13/2012, of 30 March 2012, transposing measures concerning the domestic electricity and gas markets and electronic communications, and adopting measures to remedy diversions due to gaps between the costs and revenues of the electricity and gas industries ("RDL 13/2012") transposed the provisions of the Third Electricity Directive into Spanish legislation. This transposition was completed, as regards the functions of the CNMC as the Spanish Regulatory Authority, by Royal Decree-Law 1/2019, of 11 January.

Spain has opted for full ownership unbundling ("FOU") of the TSO, by designating REE as the sole electricity transmission operator pursuant to Act 17/2007.

The process of transposition of Directives 2018/2001 and 2019/944 is still ongoing. Some provisions have been transposed into Spanish law through, among others, Royal Decree 376/2022 of 17 May and Royal Decree-Law 23/2020 of 23 June. However, others are still pending transposition.

A.2 Third party access regime

Third party access ("TPA") to the transmission and distribution networks is guaranteed subject to regulated technical and economic conditions. Access may only be refused on the basis of lack of capacity, or by reasons of security, continuity or quality of supplies.

A.3 Market design

The electricity market refers to the buying and selling of electricity by different market participants in various market sessions, such as the daily and intraday markets, forward market, and from the application of system procedures established under the System Technical Operation. Physical bilateral contracts concluded by buyers and sellers are incorporated into the generation market once the daily market has closed.

A.4 Tariff regulation

As electricity distribution and transmission are regulated activities, distribution and transmission companies receive remuneration for the construction and operation of the installations. This remuneration is paid from revenues obtained from tolls and fees, which are paid by consumers. The approval of the access tolls is administered by the CNMC and the methodology for their calculation has been established by Circular 3/2020, of 15 January.

As established by the ESA, the methodology for remunerating distribution and transmission activities will take into account the costs necessary for an efficient and well-managed company to perform the activity, with basic criteria being applied uniformly across the Spanish territory.

The methodology for calculating the remuneration applicable to transmission and distribution activities is regulated by CNMC Circulars 5/2019 and 6/2019, of 5 and 6 December, respectively. Under the ESA and these Circulars, the remuneration generated by facilities put into operation in year 'n', starts to accrue and is paid on 1 January of the year 'n+2'.

The applicable remuneration is determined by taking into account the criteria set for six-year regulatory periods. The CNMC approves the annual remuneration applicable which is paid on a monthly basis.

The methodology for calculating the financial remuneration rate for both activities is regulated by CNMC Circular 2/2019, of 12 November. This rate has been set at 5.58% for the 2020-2025 regulatory period

A.5 Market entry

Authorisations

All energy installations are subject to prior administrative authorisation, construction approval and start-up authorisation, which is only granted after applicants have certified their legal, technical and economic capacity.

Companies intending to become electricity suppliers in Spain must send a notification to the competent authority informing it of the start of the relevant activity. This notification must include a statement of responsibility confirming compliance with regulatory requirements. Regarding the distribution activities, it is important to pay attention to the requirements imposed by distributors for obtaining the necessary permits. This includes having a transformation capacity of 25 MVA, a power line length of 50 km, or serving 1,000 clients within a three-year period.

For transmission, the ESA has established that REE will act as the exclusive TSO. As manager of the transmission network, REE is also responsible for the development and enlargement of the transmission network.

Licensing regime and access and connection permits

The construction, expansion, modification, and operation of electrical installations require administrative authorisation, construction authorisation and start-up authorisation. However, the Government has defined some types of modifications that may be exempted from obtaining prior administrative authorisation and even construction authorisation.

Applicants must apply to REE or the relevant distributor for access and connection permits to the transmission or distribution networks, respectively. It must be noted that the legal framework for access and connection of electricity generation facilities in Spain has been modified. This new legal framework is essentially contained in two regulations, namely RD 1183/2020, of 29 December, and Circular 1/2021, of 20 January.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Generally, distributors must provide a regular and continuous distribution service in compliance with the quality requirements established by law, meaning that they must enlarge the distribution installations as and when necessary.

Reference suppliers must supply electricity to consumers who are eligible for the PVPC. There are also other PSOs (such as the financing of the social bonus) that are imposed on certain operators in the electricity sector.

Smart metering

The implementation of smart metering has been driven by the Energy End-use Efficiency Directive. Under Order ITC/3860/2007, of 28 December 2007, revising electricity tariffs from 1 January 2008 ("Order ITC/3860/2007"), all meters had to be replaced by 31 December 2018 in line with a systematic replacement plan.[1] In addition, the resolution dated 2 June 2015 of the State Secretariat for Energy approved the operational procedures necessary to start issuing bills to consumers equipped with smart meters based on hourly consumption and hourly prices. The first bills of this kind were issued in October 2015.

Electric vehicles

Under Law 7/2021, of 20 May 2021, relating to climate change and energy transition ("Law 7/2021"), by 2050 all passenger cars and light commercial vehicles must have no direct carbon dioxide ("CO_2") emissions. To that end, it has been indicated that by 2040 at the latest, all new passenger cars and light commercial vehicles (excluding those registered as historic vehicles) which are not used for commercial activities, must have 0gCO_2/km emissions.

Law 7/2021 also establishes the obligation to put in service at least one electricity recharging point with a continuous current power capacity of at least 50kW at gas stations with high sales volumes.

A.7 Cross-border interconnectors

Spain trades electricity with its adjacent international interconnection networks (ie France, Portugal, Morocco and Andorra). The European Commission ("Commission") has designated the enlargement of Spain's interconnection network with France as a project of common interest ("PCI").

B. Oil and gas

B.1 Industry structure

Nature of the market

The Spanish gas market is now a fully liberalised and competitive market, where suppliers sell gas at market prices. The economic regime applicable to gas supply is therefore subject to the terms and conditions agreed between the parties under each supply contract (notwithstanding other regulatory requirements that are mainly applicable when supplying to end customers).

Natural gas can be traded at liquefied natural gas ("LNG") storage tanks, natural gas storage facilities and the transmission network (at a virtual balance point), subject to the technical management rules of the system established by the technical manager of the system ("Enagas GTS").

Key market players

The key market players in the gas sector are:

- transporters: corporations authorised to construct, operate and maintain LNG terminals, transmission and basic storage facilities of natural gas;
- Enagas GTS: responsible for the operation and management of the basic and secondary transmission networks as well as maintaining the conditions for the 'normal operation' of the gas system;
- distributors: corporations authorised to construct, operate and maintain distribution facilities aimed at carrying gas to the points of supply, as well as secondary transmission facilities;
- suppliers: corporations that acquire natural gas and access third party facilities to supply consumers or other suppliers or carry out gas trading at cross-border interconnectors as well as corporate entities that sell LNG to other suppliers into the gas system or to final consumers;
- consumers: those persons or entities that acquire gas for their own consumption. Direct market consumers ("DM Consumers") are those consumers that access third party facilities directly;
- the Spanish central stockholding entity, ie Corporación de Reservas Estratégicas de Productos Petrolíferos ("CORES"); and
- the operator of the natural gas secondary market, ie Mercado Ibérico del Gas ("MIBGAS").

The main players in the Spanish gas sector are Naturgy, Endesa, Repsol, Iberdrola and Cepsa.

Regulatory authorities

The regulatory authorities for the gas market are the same as those for the electricity market (see section A.1).

Legal framework

Regulation of the natural gas industry in Spain is mainly based on the Hydrocarbons Sector Act 34/1998 of 7 October 1998 ("HSA") as amended or supplemented by other legislative instruments, which include:

- Royal Decree-Law 6/2000, of 23 June 2000, introducing urgent measures for the increase in competition in goods and services;
- Royal Decree 949/2001, of 3 August 2001, regulating TPA and establishing an integrated economic system for the natural gas sector ("RD 949/2001");
- Law 12/2007, of 2 July 2007, amending the HSA conforming it to the Internal Market in Natural Gas Directive;

- Royal Decree-Law 13/2012, of 30 March transposing directives on the internal electricity and gas markets and on electronic communications, and adopting measures to correct cost and revenue imbalances in the electricity and gas sectors ("RDL 13/2012");
- Law 18/2014, of 15 October, which approves urgent measures to encourage growth and competitiveness ("Law 18/2014");
- Law 8/2015, of 21 May 2015, amending the HSA and regulating certain tax and non-tax measures in relation to the exploration, research and exploitation of hydrocarbons;
- Royal Decree 984/2015, of 30 October 2015, regulating the organised gas market and TPA and amending RD 949/2001 ("RD 984/2015");
- Circular 9/2019, of 12 December, of the National Markets and Competition Commission, which establishes the remuneration methodology for natural gas transmission facilities and LNG plants; and
- Circular 4/2020, of 31 March, of the National Markets and Competition Commission, which establishes the remuneration methodology for the distribution of natural gas.

Implementation of EU gas directives

Regarding the Third Energy Package, RDL 13/2012 includes those provisions foreseen in the Third Gas Directive which had not previously been included in the Spanish legislation, and particularly the concept of ownership unbundling. Law 18/2014 specifies the separation of activities of the transmission network managers, the procedure for appointing the transmission network managers and the functional separation of the distributors belonging to vertically integrated groups with marketing interests. This transposition was completed, as regards the functions of the CNMC as Spanish Regulatory Authority, by Royal Decree-Law 1/2019, of 11 January.

Royal Decree-Law 34/2020, of 17 November, on urgent measures to support business solvency and the energy sector and taxation matters has implemented Directive 2019/692, of 17 April, in relation to the transmission of power lines from and to foreign countries. The Spanish legislator has opted for the FOU model but also allowed for the independent system operator ("ISO") model.

B.2 Third party access regime to gas transportation networks

TPA to the basic network facilities (primary transmission, storage, regasification and cross-border interconnectors) and transmission and distribution networks is guaranteed under regulated technical and economic conditions (RD 949/2001). This regulated TPA must be based on the principles of non-discrimination, transparency and objectivity, and its actual performance is monitored by the relevant energy authorities (mainly the CNMC). Access can only be refused on the grounds set out in the applicable regulations and any access disputes between market participants can be submitted to the CNMC for resolution. RDL 13/2012 implements, for the first time in the Spanish gas regulations, the authorisation procedure for the granting of the TPA exemption in accordance with the provisions of the Third Gas Directive. Further measures regarding the organisation and regulation of the TPA regime have been adopted pursuant to RD 984/2015.

Market players with access rights[2] (ie suppliers, DM Consumers, Enagas GTS, transmission and distribution companies and CORES) must pay a transmission and distribution fee to access the transmission and distribution networks. This fee is paid for the transportation of gas from the entrance point of the gas system to the point of supply, as well as an operating storage equivalent to two days of the contracted transmission and distribution capacity.

Parties with TPA rights must post guarantees in order to be entitled to contract capacity with the owner or operator of the relevant facilities.

B.3 LNG terminals and gas storage facilities

There are six LNG terminals in Spain, which are located in Mugardos, Bilbao, Barcelona, Sagunto, Cartagena and Huelva.

There is another LNG terminal in Gijón (*El Musel*), whose start-up authorisation was suspended in December 2012. This suspension occurred[3] due to the decreased use of natural gas in 2012 and the increase of gas imported through international pipelines. However, the Government has established the procedure by which El Musel's start-up authorisation could be awarded.[4]. In particular, from 26 May 2018 onwards, the processing of the facilities affected by said suspension resumed. Their owners had to obtain, prior to the request for the total or partial start-up authorisation, a favourable decision on the technical and economic conditions for the rendering of the capacity services and the start of operations of the associated facilities.

The Spanish gas system currently has four underground storage facilities, ie Serrablo (*Huesca*), Gaviota (offshore, Vizcaya) and Yela (*Guadalajara*), which are operated by Enagas, and Marismas (*Huelva*), which is operated by Naturgy.

Market players with access rights in accordance with RD 984/2015 (ie suppliers, DM Consumers, Enagas GTS, transmission and distribution companies and CORES) must pay the following fees and royalties to access LNG terminals and storage facilities (as applicable): regasification fee, underground gas storage royalty and LNG storage royalty.

Parties with TPA rights must post guarantees in order to be entitled to contract capacity with the owner or operator of the relevant facilities.

B.4 Tariff regulation

The main source of income for a company dedicated to regulated activities in the Spanish natural gas market is the remuneration defined and settled by the regulators as part of the periodic system of costs settlements.

Under the current regulatory framework, the purpose of this remuneration is to enable companies performing regulated activities to recover their investment, pay the costs of running and maintaining the transmission and distribution networks, and to earn a reasonable return. The annual amounts to be paid to each relevant company are set out in accordance with the rules laid down in the HSA.

Remuneration is governed by the principle of economic and financial sustainability, defined as the ability of the Gas System to cover all the costs it generates and allow adequate remuneration for low-risk regulated activities.

The remuneration parameters applicable to those activities are established for regulatory periods of six years.

The methodology for calculating the remuneration applicable to natural gas transmission facilities and LNG plants is regulated by Circular 9/2019, of 12 December, of the National Markets and Competition Commission. The methodology for calculating the financial remuneration rate for both activities is regulated by CNMC Circular 2/2019, of 12 November, and this rate has been set at 5.44% for the 2021-2026 regulatory period.

The remuneration methodology for the distribution of natural gas is regulated by Circular 4/2020, of 31 March, of the National Markets and Competition Commission.

Law 18/2014 establishes the methodology for the remuneration of natural gas storage facilities.

B.5 Market entry

Authorisations

In accordance with applicable regulations, companies intending to carry out the transmission, distribution or supply of natural gas are not required to have a permanent establishment in Spain.

Under the HSA, transmission and distribution companies are those companies authorised for the construction and operation of transmission and distribution facilities, respectively. It is therefore necessary to hold these authorisations to become a transmission or a distribution company. Companies intending to become natural gas suppliers in Spain must notify the relevant authorities that they comply with the requirements necessary to carry out those activities, including their legal, technical, and economic capacities. The notice must be given to the competent authority at the start of the activity. The notice must include a statement of responsibility confirming compliance with regulatory requirements and a sales forecast.

Licensing regime

In a similar manner to the electricity sector, the construction, enlargement, modification and operation of gas storage, regasification, transmission and distribution installations follows a three-phase authorisation procedure (ie administrative authorisation, construction approval and start-up authorisation).

The market is also divided into regulated activities, ie gas storage, regasification, transmission and distribution, and unregulated activities, ie production and supply.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

Generally, distributors must provide a regular and continuous distribution service in compliance with the quality requirements established by law, in particular, the Safeguard of Security of Gas Supply Directive, and thereafter the Third Gas Directive, which requires Member States to ensure that household customers (and small companies, where appropriate) are entitled to a supply of natural gas of a specified quality at clearly comparable, transparent and reasonable prices. Those rules provide for the possibility of designating a supplier of last resort.

In relation to supply, certain customers (currently restricted to customers with a supply pressure of less than four bar and whose annual consumption is less than 50,000kWh) have a legal right to be supplied at prices established in accordance with the Tariffs of Last Resort and offered by the Suppliers of Last Resort ("SOLRs"). SOLRs are marketing companies designated by the Government that carry out their activities under the same operating regime as the rest of the retail suppliers, but at the price set by the Tariff of Last Resort.

Smart metering

The implementation of smart metering is driven by the Energy End-use Efficiency Directive, which provides that Member States will ensure the use of systems of smart metering. No deadline has been set for this obligation in respect of natural gas, however, Member States must develop a schedule for its implementation. To date, Royal Decree 736/2020, of 4 August, regulates the accounting of individual consumption in thermal installations of buildings.

B.7 Cross-border interconnectors

There are currently six cross-border interconnectors in Spain, ie two with Africa (Maghreb and Medgaz natural gas pipelines through Tarifa and Almería), two with France (Larrau and Irún) and two with Portugal (Badajoz and Tuy).

As cross-border interconnectors are considered to be part of the gas network (unless specifically exempted), the TPA regime is the same as the regime described for TPA to gas transportation networks (see section B.2). However, Royal Decree-Law 34/2020 allowed the Maghreb and Medgaz pipelines to request an exemption from the TPA regime for a maximum period of 20 years (until 24 May 2040), which may be extended under certain circumstances. By Order TED/740/2021, of 5 July, the Medgaz gas pipeline was granted the aforementioned exemption until 31 March 2031, whereas Order TED/741/2021, of 5 July, granted this exemption to the Maghreb gas pipeline until 31 October 2021 (as is well known, the Government of Algeria ceased its gas exports to Spain through the Maghreb pipeline on 1 November 2021).

C. Energy trading

C.1 Electricity trading

Electricity is generated within a framework of free competition in the electric power generation market. Generally, the market is organised by means of a spot market (physical transactions) and a future market (financial transactions). The spot market includes day-ahead and intraday markets.

Physical and financial electricity transactions may also be negotiated through bilateral contracts. There are numerous variations to the standard hedging contracts. These hedging products can be traded though OMIP/OMIClear (*Operador do Mercado Ibérico Português*) or over-the-counter (OTC).

Electricity supply related activities are remunerated on the basis of tariffs, fees and market prices, depending on whether the activity is regulated or unregulated.

The Spanish electricity legislation provides for the following three forms in which suppliers can supply electricity to consumers:

- Reference supply, of which there are two methods: (i) the PVPC method, which has applied by default from 1 July 2014 if the consumer was subject to the previous last resort tariffs (ie TUR); and (ii) the annual fixed price method in a regulated market offered by the reference trader.

- Contracting in the deregulated market with a trader.
- Last resort supply, to which the 'social bonus' tariff applies (see section A.1).

Royal Decree 216/2014, of 28 March 2014 established the methodology for calculating the PVPC.

C.2 Gas trading

Natural gas suppliers can sell and purchase natural gas amongst themselves through private bilateral transactions or bilateral transactions operated in an organised market, subject to relevant regulatory requirements (see section B.1).

Private bilateral transactions are usually governed by a master agreement contract subject to Spanish law and confirmation notices, which are tailored to each particular transaction.

Bilateral transactions are closed in the natural gas organised market operated by MIBGAS. To operate in the organised market, suppliers must become accredited parties, sign a contract of adhesion to the rules on the organised gas market, and fulfil the requirements specified in those rules (including posting guarantees). Suppliers can also participate in the market through an authorised representative.

D. Nuclear energy

In 2019, the Government signed a Protocol with the owners of the nuclear power plants to proceed with their progressive closure. According to the schedule incorporated into that Protocol, all nuclear power plants must have ceased their activity by 2035.

To date, nuclear power plants have, generally, operated under a definitive extendable ten-year operating licence. For Almaraz I and Almaraz II, this operating licence was recently extended[5] to 1 November 2027 and 31 October 2028, respectively.

The current plants and shareholdings are:

CENTRAL	OWNED BY	EXPECTED CLOSING DATE	INSTALLED POWER OUTPUT (MW) AND TYPE[6]
Almaraz I (Cáceres)	Iberdrola Generación SA (52.7%), Endesa Generación SA (36.0%) and Unión Fenosa Generación (11.3%)	1 November 2027	1,035.30 PWR
Ascó I (Tarragona)	Endesa Generación SA (100%)	2029	1,032.50 PWR
Almaraz II (Cáceres)	Iberdrola Generación SA (52.7%), Endesa Generación SA (36%) and Unión Fenosa Generación (11.3%)	31 October 2028	1,045 PWR
Cofrentes (Valencia)	Iberdrola Generación, Nuclear SA (100%)	2030	1,092.02 BWR
Ascó II (Tarragona)	Endesa Generación SA (85%) and Iberdrola Generación SA (15%)	2033	1,027.21 PWR
Vandellós II (Tarragona)	Endesa Generación SA (72%) and Iberdrola Generación SA (28%)	2035	1,087.14 PWR
Trillo (Guadalajara)	Iberdrola Generación SA (48%), Unión Fenosa Generación (34.5%), Hidroeléctrica Cantábrico (15.5%) and Nuclenor (2%)	2035	1,066 PWR

The Spanish Nuclear Safety Council (*Consejo de Seguridad Nuclear*) (created by Act 15/1980, of 22 April 1980) is the only body with competence in the field of nuclear safety. It is independent of the State Administration and reports directly to the Congress and the Senate.

Royal Decree 1836/1999, of 3 December 1999, which approves the regulations on nuclear and radioactive installations, establishes several kinds of applicable authorisations depending on the type of installation. Nuclear power plants will require the following authorisations, among others:

- prior authorisation or site authorisation;
- construction permit;
- operating, modification or dismantling authorisations;
- dismantling authorisation; and
- change of owner of nuclear installations.

Regarding nuclear liability for environmental damages, the Spanish Nuclear Energy Act 25/1964, of 29 April 1964, states that the owners of nuclear installations and of the transport of nuclear material will be liable for any environmental damage caused in Spain as a result of accidental leakage of ionising radiation to the environment, originating from such installations or transport (ie, a risk coverage of around €700 million). Act 15/2012 introduced the following two new taxes in relation to nuclear energy:

- tax on the production of spent nuclear fuel and radioactive waste resulting from nuclear power generation; and
- tax on the storage of spent nuclear fuel and radioactive waste in centralised plants.

For the production of spent nuclear fuel and radioactive waste resulting from nuclear power generation the following tax rates apply:

- for spent nuclear fuel, €2,190 per heavy metal kilogramme; and
- for radioactive waste resulting from nuclear power generation, €6,000/m^3 (low or medium activity radioactive waste) or €1,000/m^3 (very low activity radioactive waste).

For the storage of spent nuclear fuel and radioactive waste in centralised plants, the following tax rates apply:

- depending on the specific nuclear fuel or radioactive waste, €70 per heavy metal kilogramme; or
- for radioactive waste, a tax rate ranging from €2,000/m^3 to €30,000/m^3.

These two taxes in relation to nuclear energy imply an estimated total cost for the nuclear sector of €300 million per year, which is intended to pay the regulated costs of the electricity system rather than the management of the nuclear waste produced.

The Spanish Supreme Court, in Judgement 825/2021, of 10 June, declared theses taxes were in compliance with the constitutional order and the EU order (after submitting a preliminary question to the Court of Justice of the EU (CJEU), which was resolved by a Judgement of 3 March 2021)

E. Upstream

Although there is a very limited amount of natural gas production in Spain, Title II of the HSA establishes a legal regime for exploration, investigation, and the exploitation of hydrocarbon deposits. These activities are subject to obtaining the relevant permits, authorisations, and concessions (for exploitation and production activities).

Act 7/2021 has however prohibited the granting, within the territory of Spain (including the territorial sea, the exclusive economic area ("EEA") and the continental shelf), of new exploration authorisations, research permits or concessions for the exploitation of hydrocarbons. As an exception, a new exploitation concession may be awarded if: (i) connected to a valid research permit; and (ii) its application was already being processed on 22 May 2021, when the Law entered into effect. In this case, the concession will have a maximum term of 30 years.

Act 7/2021 also establishes: (i) that the research permits and concessions for the exploitation of hydrocarbon deposits located in the territorial sea, EEA and the continental shelf that are in force cannot be extended beyond 31 December 2042; and (ii) the absolute prohibition of authorisations for high-volume hydraulic fracturing ("fracking").

F. Renewable energy

F.1 Renewable energy

Royal Decree 413/2014, of 6 June 2014, regulates the generation of electricity from RES, cogeneration and waste ("RD 413/2014"). The decree approved a new system of specific remuneration (*retribución específica*) in Spain. This remuneration is in addition to the remuneration received for the sale of energy valued at market rates for certain plants that generate electricity using renewable energy, cogeneration, or waste-to-energy technologies (including biomass plants). The new system of specific remuneration allowed recovery of the costs that were necessarily incurred to compete on an equal footing with other technologies, while obtaining a reasonable rate of return in reference to the standard plant applicable in each case.

The specific remuneration regime is composed of a return on investment and a return on operation. In addition, exceptionally, it is possible for the remunerative regime to include a subsidy for investment in non-peninsular power systems when the overall cost of electricity generation is reduced, as well as a subsidy for participation in what are known as system adjustment services. Plants that participate in system adjustment services receive the remuneration established by applicable regulations.

To calculate the specific remuneration, each plant is allocated a standard reference plant on the basis of its characteristics. As established by RD 413/2014, a set of remuneration parameters apply to each standard plant. These parameters make up the specific remuneration applicable to the plants falling under the umbrella of each standard plant. In particular, this specific remuneration system applies to:

- Existing plants that had already been awarded a premium-based remuneration when Royal Decree-Law 9/2013, of 12 July 2013, which adopted urgent measures to guarantee the financial stability of the electricity system entered into force, subject to the specific criteria established under the additional and transitional provisions of RD 413/2014.
- Solar thermal plants that were awarded support under the remunerative regime established in Royal Decree 1565/2010, of 16 November, which regulates and modifies certain aspects of special-regime electricity generation.
- New plants. In general, plants will be awarded the specific regime by a competitive tender process. To date, three renewable energy auctions have been held awarding the specific remuneration: (i) on 14 January 2016 for biomass and wind power generation facilities; (ii) on 17 May 2017 for any new renewable energy power generation facility; and (iii) on 26 July 2017 for wind and photovoltaic ("PV") power generation facilities.

  In these auctions, the product auctioned was the installed capacity entitled to receive the specific remuneration and the bids consisted of a percentage reduction of the standard value of the initial investment defined for each standard plant in the respective order. These auctions were marginalist in nature. Consequently, the last bid falling within the power to be awarded was the one that determined the value of percentage reduction of the standard value of the initial investment of each reference standard plant, and, as a consequence, its specific remuneration for the entire regulatory lifetime (which, for example, was set at 20 years for wind power and 30 years for PV).

RD 413/2014 establishes consecutive regulatory periods of six years, each divided into two half-periods of three years. The first regulatory period ran from 14 July 2013 to 31 December 2019 and the second regulatory period runs from 1 January 2020 to 31 December 2025. The remuneration parameters are reviewed as follows:

- At the end of each six-year regulatory period, all remuneration parameters, including the reasonable rate of return, may be reviewed by ministerial order, except for the regulatory working life and the standard value of initial investment applicable to a standard plant, which cannot be reviewed. The rate of return for all facilities which were allocated subsidised remuneration prior to 14 July 2013 is set at 7.389% for the next twelve years (from 1 January 2020 to 31 December 2031).[7] This value for the reasonable return, however, will not be applicable to those plants for which judicial or arbitration proceedings challenging the new remuneration regime have been or will be initiated in the future. In this case (unless the legal or arbitration proceedings or the compensation that may have been awarded in these proceedings were waived by the claimants before 1 October 2020), and in the case of facilities for which the right to the specific remuneration has been recognised after 14 July 2013, the value of the reasonable rate of return for the following regulatory period (from 1 January 2020 to 31 December 2025) will be 7.09%. In addition, Order TED/171/2020, of 24 February, has updated the remunerative parameters for the second regulatory period that runs from 1 January 2020 to 31 December 2025.
- At the end of each regulatory half-period a ministerial order will review the estimated standard revenues generated by each standard plant as a result of the sale of energy at market price, as well as the remuneration parameters directly related to them
- Additionally, the return on operation applicable to technologies whose operating costs essentially depend on the price of fuel is reviewed every six months. However, Royal Decree-Law 6/2022, of 29 March 2022, which adopts urgent measures in the context of the National Plan of response to the economic and social impact of the war in Ukraine ("RDL 6/2022"), contains a mandate to the Government to develop a new updating methodology, which would be annual (this new methodology is still pending approval).

As an exception, RDL 6/2022 ordered an extraordinary review of the parameters applicable to the year 2022, which has been carried out by Order TED/1232/2022, of 2 December.

Although this scheme has not been repealed and could, theoretically, be applied in the future (mainly for some renewable technologies whose costs are above the market price and, above all, for cogeneration facilities undergoing renovation) the Spanish Government has made it clear that, as far as renewable installations are concerned, future auctions will be held under the 'remunerative framework for renewable energy' (*régimen económico de energías renovables*, or "REER"), which is regulated in Article 14.7 bis of the ESA and Royal Decree 960/2020, of 3 November, which regulates the economic regime of renewable energies for electricity generation facilities ("RD 960/2020").

The REER, unlike the specific remuneration scheme, is not complementary but alternative in nature. Installations that have been granted the REER cannot enter physical PPAs and, although they must participate in the daily and intraday market, they will receive the remuneration allocated to them under the REER for the energy traded.

The main characteristics of the REER are:

- Eligible facilities: Only renewable energy facilities will be eligible to receive the REER[8]. Furthermore, it requires that those facilities be the result of a "*new investment made after the corresponding auction has been held*", whether because the facility is totally new or because an enlargement or modification has been made to an existing facility (although, in the latter case, it will only apply to the energy generated by the enlargement or modification). However, it is expressly established that the facilities signed up to the REER may use more than one technology, which must be renewable (therefore including hybrid facilities), including storage facilities.
- New auction mechanism. Generally, the REER will be awarded at auction. However, as an exception, facilities with an installed power capacity of less than 5MW and demonstration projects are eligible to receive the REER directly (without the need to take part in auctions)[9].

The details of the auction mechanism will be defined in a MITERD order, which may define, among other things, the technologies, terms and conditions and the guarantees that must be furnished to take part in the auction, the product being auctioned, as well as the parameters and other elements of which the REER is composed. In particular, the order may establish mechanisms that guarantee project maturity, as well as any other requirement aimed at ensuring their viability. This may include establishing milestones that must be met prior to the completion of construction. Such milestones might analyse project construction and permitting progress and their fulfilment will be taken into account for the purpose of the facility obtaining final registration in the REER Electronic Register and when releasing or partially enforcing guarantees, as appropriate.

The first of these orders has been Order TED/1161/2020, of 4 December, regulating the first auction mechanism for the granting of the remunerative framework of renewable energy and establishing the indicative auction calendar for the period 2020-2025 ("Order TED/1161/2020").

Having approved the order, each auction is called by decision of the Secretariat of State for Energy. To date, four auctions have been held under this new mechanism: on 26 January 2021, 19 October 2021, on 25 October 2022 and 22 November 2022. Order TED/1161/2020 establishes the indicative auction calendar for the period 2022-2026.[10]

Auctions may be technology neutral or technology specific based on, among other criteria, their technical characteristics, scale, degree of dispatchability, localisation criteria and technological maturity. Tenderers must submit sealed bids in terms of €/MWh (to two decimal places) Auctioned energy will then be awarded on a 'pay as bid' basis.

The auction will award a certain power or capacity or energy, depending on the product up for auction, to each tenderer, as well as a price, which will match the tenderer's financial bid.

The REER will, by default and for each respective facility awarded the REER at auction, have a term equal to the supply term established at each respective auction (which should, generally, range between ten and 15 years, but which may exceptionally reach 20 years). However, the REER will also come to an end if, before that term expires, the awardee facility supplies the maximum volume of power awarded or if that facility withdraws from the REER, which it may do without penalty once the minimum volume of energy has been supplied (otherwise, if that minimum volume is not achieved, a penalty will be imposed).

The REER will be financed and paid by the electricity wholesale market. OMIE will settle the difference, which may be positive or negative, between the spot and intra-day market prices and the price established for each facility awarded the REER. If the spot price is higher than the awarded price, the facility will only receive the award price (as applicable, adjusted with the market incentive, if one has been defined) and its difference with the spot price will be distributed by OMIE as income among national energy buyers. If the spot price is lower, the owner of the facility receiving the REER will be entitled to receive the difference, which will be settled as a market cost payable by energy buyers in that same proportion.

F.2 Renewable pre-qualifications

As stated above, the details of the auction mechanism are defined in a MITERD order, which may define, among other things, the technologies, terms and conditions, guarantees that must be furnished to take part in the auction, the product being auctioned, as well as the parameters and other elements of which the REER is composed.

These details are further specified by the decisions of the Secretariat of State for Energy calling the specific auction.

For instance, the auction held on 25 October 2022 called by resolution of 18 July 2022 of the Secretariat of State, intended to allocate up to:

- 380MW to facilities belonging to the groups and subgroups b.1.2, b.3, b.4, b.5, b.6, b.7 and b.8; and
- 140MW to photovoltaic facilities of distributed generation with local nature belonging to subgroup b.1.1.

In particular, these facilities had to comply with the following requirements:

- be found in the peninsular electrical system;
- be new facilities of groups and subgroups b.1.1, b.1.2, b.3, b.4, b.5, b.6, b.7 and b.8, or modifications of existing facilities of groups b.4 and b.5, in the terms of the definition foreseen in Article 2.3 of Order TED/1161/2020;
- have no storage system or, otherwise, that the storage system be used for the exclusive storage of the energy generated by the facility;
- facilities of groups b.6, b.7 and b.8 must comply with the sustainability and greenhouse gas emission ("GHG") reduction criteria and the energy efficiency requirements set forth in Chapter 5 of Title 1 of Royal Decree 376/2022, of 17 May 2022, regulating the sustainability and GHG emission reduction criteria for biofuels, bioliquids and biomass fuels, as well as the guarantees of origin ("GO") system for renewable gases; and
- facilities of groups b.4 and b.5 must have a water concession covering up to at least the end date of the maximum term for delivery.

However, the result of the auction led only to the allocation of 146 MW to subgroup b.6 facilities and 31 MW to photovoltaic facilities of distributed generation with local nature belonging to subgroup b.1.1.

F.3 Biofuel

The main Spanish regulations applicable to biofuel are:

- Royal Decree 1088/2010, of 3 September 2010, which partially transposed the Biofuel Directive and amended Royal Decree 61/2006, of 31 January 2006, regarding the technical specifications applicable to petrol, diesel and gas-oil, the use of biofuels and the sulphur content of fuels for sea-bound vessels.
- Royal Decree 459/2011, of 1 April 2011, which established mandatory biofuel targets for 2011, 2012 and 2013, established a global target of 6.5% for 2012 and a diesel biofuel target of 7%.
- Royal Decree 1597/2011, of 4 November 2011, which introduced into Spanish legislation the biofuel and bio-liquid sustainability criteria outlined in European regulations and established a system to monitor the fulfilment of those criteria. It also introduced into Spanish legislation the provisions of European regulations on the dual value of certain biofuels with the aim of complying with mandatory targets in relation to energy from RES for transportation.
- Royal Decree 1085/2015, of 4 December 2015 on the promotion of biofuels (recently amended by Royal Decree 205/2021, of 30 March, which establishes biofuels targets for 2021 and 2022).

G. Climate change and sustainability

G.1 Climate change initiatives

The Climate Change Package and The Energy and Climate Package have been implemented in Spain primarily by means of the following regulatory instruments:

- Act 13/2010, of 5 July ("Act 13/2010")[11], which regulates GHG emissions allowance trading ("Act 1/2005"), to optimise and extend the general scheme for GHG emissions allowance trading and to include aviation activities in that regulation.
- Act 40/2010 on the geological storage of carbon dioxide ("Act 40/2010"). The aim of Act 40/2010 is to transpose the provisions of the CCS Directive into Spanish regulations ("Carbon Storage Act").
- The Renewable Energy Directive was implemented by RDL 13/2012, Royal Decree 1597/2011, of 4 November 2011 and Royal Decree 1085/2015, of 4 December 2015.
- The Biofuel Directive has been partially implemented into Spanish law by Royal Decree 1088/2010, of 3 September 2010,[12] regarding the technical specifications applicable to petrol, diesel and gas-oil, the use of biofuels and the sulphur content of fuels for sea-bound vessels; and by Royal Decree 1085/2015, of 4 December 2015, on the promotion of biofuels.
- The Renewable Energy Directive II (Directive 2001/2018) has been partially implemented into Spanish Law by: i) Royal Decree 244/2020, of 5 April 2020, in relation to renewables self-consumers; ii) Royal Decree-Law 23/2020, of 23 June 2020, in relation to renewable energy communities; iii) Royal Decree 960/2020, of 3 November 2020, in relation to support schemes for energy from renewable sources.
- Directive 2019/944, of 5 June 2019, has been partially implemented into Spanish Law (in relation to energy storage facilities and aggregation by Royal Decree-Law 23/2020, of 23 June 2020.
- Act 7/2021, on climate change and energy transition, establishes national targets for 2030 and 2050 in the matter

of renewable energy, energy efficiency and the reduction of GHG emissions. These targets are more ambitious that those established, for the EU overall, in the different instruments of the Energy and Climate Package. Targets for 2030 include a 23% reduction of GHG emissions[13] (compared to 1990), 42% of final energy consumption from RES, a 74% of electricity generation from RES, and a 39.5% reduction in the consumption of primary energy in respect of the baseline under EU regulations. In 2050 Spain should achieve climate neutrality and 100% of electricity generation from RES.

G.2 Emission trading

On 6 July 2010, the Spanish State Gazette (*Boletín Oficial del Estado*) published Act 13/2010, amending Act 1/2005, with the aim of transposing into Spanish law the New EU ETS Directive, as well as the Aviation Activities Directive, which includes aviation activities in the scheme for GHG emissions allowance trading within the EU from 2012.

The Spanish Sustainable Economy Act 2/2011 was published in the Spanish State Gazette on 5 March 2011, creating a Carbon Fund for a Sustainable Economy ("Carbon Fund").[14] The Carbon Fund is financially dependent on the allocation made each year in the General State Budget as well as on any revenues obtained from the management of its assets.

On 17 December 2020, the Spanish State Gazette published Act 9/2020, amending Act 1/2005, with the aim of transposing into Spanish law the Directive 2018/410, which amended the EU ETS Directive.

G.3 Carbon pricing

In Spain

On 30 October 2013, the Spanish State Gazette (*Boletín Oficial del Estado*) published Act 16/2013 of October 29, adopting certain regulations on environmental taxation and adopting other fiscal and financial measures ("Act 16/2013").

Article 5 of Act 16/2013, in effect since 1 September 2022, as well as Royal Decree 712/2022, of 30 August 2022, which approves the Regulation of the Tax on Fluorinated Greenhouse Gases, regulate the tax on fluorinated GHGs, which is aimed at curbing emissions from fluorinated GHGs ("F-gases").

This tax is levied on Hydrofluorocarbons (HFCs), perfluorocarbons (PFCs) and sulphur hexafluoride (SF6) listed in Annex I of Regulation (EU) No. 517/2014 of the European Parliament and of the Council of 16 April 2014 on F-gases and repealing Regulation (EC) No. 842/2006 ("Regulation (EU) 517/2014"), as well as mixtures containing any of those substances.

In general terms, the tax applies to the manufacture, importation, intra-EU acquisition or irregular possession of F-gases and is calculated according to the weight of the F-gases.

The use of F-gases in certain sectors and for certain purposes is also (partially) exempt from the tax, such as those intended to be used as feedstock for chemical transformation in a process in which these gases are entirely altered in their composition. Other F-gases are non-taxable, such as those with a global warming potential (GWP) of below 150 or intended to be exported.[15]

In the Autonomous Region of Cataluña

The Autonomous Region of Cataluña introduced provisions in Regional Act 16/2017, of 1 August, on Climate Change for a tax which will apply to GHG emissions from large installations in the power, industry, agriculture, and waste sectors, including EU ETS installations. Income from the tax would go to a Climate Fund to be used for climate change mitigation and adaptation policies.

The legislative development process was delayed because the law was assessed and deemed unconstitutional by the Spanish Constitutional Court in June 2019. The tax will need further legal framework to be operationalised.

Regarding recent developments, the vice-presidency of Economy and Finance of the Autonomous Region of Cataluña initiated a public consultation process on 3 January 2022 with the aim of guaranteeing the applicability of the tax on GHG emissions generated by economic activities and achieving the energy transition objectives established by Regional Act 16/2017, of 1 August, on Climate Change. This public consultation ended on 4 March 2022.

G.4 Capacity markets

The order developing a capacity market in the Spanish system (the "Order") was submitted for public consultation from 19 April 2021 until 12 May 2021. However, it has not been approved yet.

The Order's system will be centralised, and through it the system operator (ie REE) will contract the firm capacity needs (in MW) identified in the demand coverage analysis.

The procedure will be conducted by a single node probabilistic analysis and determine the power requirements. Auctions will be called by resolution of the Secretary of State for Energy and may fall under two categories: (i) main auction (*subasta principal*), for a maximum period of five years from the assignment of the auction; and (ii) adjustment auction (*subasta de ajuste*), which consists on the assignment of a maximum period of 12 months from the allocation of the service following the auction.

The main auctions are expected to guarantee the power needs of the mainland electricity system, while at the same time encouraging investment in manageable assets such as storage; while the adjustment auctions are intended to resolve any coverage problems that will not be covered by means of the firm power guaranteed through the main capacity auctions.

The Order also regulates aspects related to the rights and obligations of capacity service providers, including their remuneration system or the penalty scheme in the event of non-compliance by the aforementioned parties.

H. Energy transition

H.1 Overview

As a Member State of the EU and signatory to the Paris Agreement, Spain is firmly committed to achieving climate neutrality by 2050, while taking advantage of the opportunities offered by this energy transition in terms of the economy and job creation.

Spain continues on the path towards decarbonisation, with policies and regulations that seek to direct investments towards achieving an emission-free economy.

In this sense, the approval of Law 7/2021, of 20 May 2021, on climate change and energy transition ("Law 7/2021") must be highlighted. Law 7/2021 establishes national targets for 2030 and 2050 in the matter of renewable energy, energy efficiency and the reduction of GHG emissions. Specifically, has set the following targets for 2030:

- 23% reduction of GHG emissions compared to 1990;
- 42% of final energy consumption from RES;
- 74% of electricity generation from RES; and
- 39.5% reduction in the consumption of primary energy in respect of the baseline under EU regulations.

Spain has also set the following targets for 2050:

- achieving climate neutrality; and
- 100% of electricity generation from RES.

The Council of Ministers may still review and expedite these objectives by means of an amendment (*cláusula de deslegalización*); it is planned that the first review will take place in 2023.

H.2 Renewable fuels

Hydrogen

Latest developments regarding renewable fuels such as hydrogen and ammonia include the following three regulations:

- Royal Decree 376/2022, of May 17 2022, which regulates the criteria for sustainability and reduction of GHG emissions from biofuels, bioliquids and biomass fuels, as well as the system of GO of renewable gases ("RD 376/2022").
  - RD 376/2022 enables the identification and certification of gases of a renewable origin, such as biogas, biomethane or hydrogen, through the implementation of a system which is similar to that used with renewable energy.
  - Through the GOs, each MWh of renewable gas produced will lead to the emission of a GO containing information on where, when, and how the gas was produced.
  - RD 376/2022 creates a Census of Gas Production Facilities from Renewable Sources and a Producers Committee, which will allow suppliers and distributors to exchange the GO in a transparent and secure way within the system, which will in turn keep record of the creation, transfer, and cancellation of GO.
- RDL 6/2022 of 29 March 2022.
  - RDL 6/2022 establishes the possibility of developing standalone pipelines and facilities (ie not connected to the gas system) to supply renewable gases (which include, among others, renewable hydrogen). This therefore opens the door to the development of exclusive networks to supply renewable gases, independently of the currently existing possibility (albeit subject to technical limitations) of it being injected into the gas networks.
  - Those pipelines, which are subject to the provisions established in the HSA, are declared to be of general interest (and do not include renewable gas production facilities and the direct pipelines referred to below) and of public interest for the purposes of exercising expropriation procedures and rights of way.
  - Regarding TPA to the pipelines, it must be negotiated on the basis of the principles of transparency, objectivity and non-discrimination, and the CNMC will set access criteria it this is considered to be appropriate.
  - The commercialisation of renewable gases using facilities of this kind will be subject to the provisions of the HSA regarding the commercialisation of natural gas, except for the obligation to keep minimum security stocks due to the supply of natural gases. This activity is compatible with the commercialisation of natural gas and electricity and separate accounting must be kept.
  - Consumers connected to these facilities will enjoy the same rights and obligations as established for consumers of natural gas.
- Royal Decree-Law 14/2022, of 1 August 2022, on economic sustainability measures related to transport, scholarships, and grants, as well as measures related to energy efficiency and saving and to reduce power dependence on natural gas ("RDL 14/2022"). RDL 14/2022 introduces a series of measures aimed at simplifying the administrative process related with renewable gases, specifically:
  - An exemption is applied to the need for authorisation of all direct pipelines, thus amending Article 55 of the HSA. Previously, that exemption applied to direct natural gas pipelines connecting a consumer with the gas system. Now the exemption applies without distinction and therefore also to direct pipelines connecting a renewable gas production plant with the gas system aimed at feeding gas into it, which may now be built without having to meet any requirements other than those related to the fulfilment of technical, safety and environmental provisions.
  - An amendment is made to Article 56 of the HSA to exclude renewable gas production plants from the concept of plants that manufacture gas fuels. This means that they will now be exempt from the system of authorisation and from the planning criteria existing with regard to hydrocarbons.
  - Article 12 bis is added to Royal Decree 1434/2002, of 27 December 2002, regulating the transport, distribution, commercialisation and supply activities and the procedures for the authorisation of natural gas facilities, to regulate the connection of renewable gas production plants to the gas transport or distribution networks. In essence, it establishes that: (i) the producers of renewable gases who wish to connect to a gas transport or distribution network will send the gas transporter or distributor a request to connect to that network, indicating the expected flows and pressure at which the gas will be injected, as well as the expected quality of that gas; (ii) the gas transporters or distributors must answer within 40 working days, indicating the most suitable connection point, the technical conditions for the connection, the maximum admissible flow, the cost of making the connection and the timeline for performing it; (iii) the costs incurred when making the connection will in any event be borne by the requesting producer; and (iv) any potential discrepancies may be referred to the CNMC (when the network connected to is the responsibility of the General State Administration) or the respective regional authority (otherwise), which must provide an answer within three months.

- Royal Decree-Law 18/2022, of October 18, approving measures to reinforce the protection of energy consumers and to contribute to the reduction of natural gas consumption in application of the "Plan + seguridad para tu energía (+SE)", as well as measures regarding the remuneration of public sector personnel and the protection of temporary agricultural workers affected by the drought ("RDL 18/2022"). RDL 18/2022 establishes that direct lines connecting a renewable gas production plant to the gas system for the purpose of injecting gas into the gas system may be subject to a declaration of public utility for the purposes of compulsory expropriation.

Specifically with regards to hydrogen, other relevant developments include:

- Strategic Project for the Recovery and Economic Transformation of Renewable Energy, Renewable Hydrogen and Storage (PERTE ERHA), approved by the Government on 14 December 2021. The two tenders published under the PERTE ERHA are regulated by the following two orders:
  - Order TED/1444/2021, of 22 December 2021, approving the regulatory bases for the granting of aid corresponding to the incentive program for the innovative and knowledge value chain of renewable hydrogen within the framework of the Recovery, Transformation and Resilience Plan ("Order TED/1444/2021").

    Order TED/1444/2021 approves the regulatory bases for the granting of aid corresponding to the program of incentives for the innovative value chain and knowledge of renewable hydrogen.

    It is endowed with €250 million and seeks to promote the manufacture of components, prototypes of new vehicles or electrolyser projects to produce renewable hydrogen on a large scale.

    The proposed provisional resolution of this tender was published on 23 December 2022.
  - Order TED/1445/2021, of 22 December 2021, approving the regulatory bases for the granting of aid corresponding to the incentive program for pioneering and unique renewable hydrogen projects within the framework of the Recovery, Transformation and Resilience Plan ("Order TED/1445/2021").

    Order TED/1445/2021 approves the regulatory bases for the granting of aid corresponding to the incentive program for pioneering and unique renewable hydrogen projects.

    It is endowed with €150 million for projects with commercial viability, local hydrogen production and consumption, or in sectors that are difficult to decarbonise, such as industry or heavy transport.

    The proposed provisional resolution of this tender was published on 1 December 2022.

Ammonia

With regard to ammonia, the Hydrogen Roadmap approved by the Government on 9 October 2020 highlighted its importance as an energy vector, as it can be very useful to transport renewable hydrogen; however, there are currently no regulations specifically on renewable ammonia.

H.3 Carbon capture and storage

The Carbon Storage Act regulates the geological storage of CO_2 and only contains very limited provisions in relation to capture and transportation. The Carbon Storage Act contains the basic elements of the legal scheme, such as the research permit (to determine the storage capacity or the suitability of a specific site) and the storage concession (an exclusive right to store CO_2 in a specific place), which can be granted by the Ministry of Energy, Tourism and Digital Agenda.

Responsibility for the site will transfer to the state when it has evidence that the CO_2 stored will remain totally and permanently contained within the site and when at least 20 years have elapsed from site closure (unless the Ministry of Energy, Tourism and Digital Agenda decides on a shorter term).

The Carbon Storage Act also envisages a CO_2 storage site monitoring fund to cover the costs of monitoring the sites, as well as the cost of guaranteeing that the CO_2 remains completely contained after responsibility has been transferred to the state.

H.4 Oil and gas platform electrification

There is currently no oil and gas platform electrification in Spain.

H.5 Industrial hubs

HyDeal Ambition is a collaborative platform comprising up to 30 actors from the energy sector, as well as consultancy, engineering and law firms, investment banks and digital companies that aims to develop an integrated value chain that sells green hydrogen in Europe at the price of fossil fuels. The HyDeal Ambition project is led and integrated by the company DH2 Energy, which produces and distributes hydrogen.

HyDeal Ambition will be developed first in Spain and Southwest France, and then extended to Eastern France and Germany. Further development from North Africa to Italy and across Central Europe is also contemplated.

It comprises several phases:

- 2022-2024: existing pipelines and infrastructure will be used to transport green hydrogen, mixed with natural gas.
- From 2025 onwards: dedicated infrastructure will be used to transport green hydrogen, with less use of natural gas.
- From 2025: transport system from Spain to Northern France and Germany.

HyDeal Spain is the first industrial implementation of the HyDeal Ambition platform, officially constituted as an industrial joint venture in November 2021.

It is an initiative driven by ArcelorMittal S.A., Enagás, S.A., Grupo Fertiberia, S.A. and DH2 Energy, and is expected to be the largest renewable hydrogen giga-project in the world, according to the classification of the International Renewable Energy Agency. It comprises the development, financing and construction of a set of infrastructures for the production and transportation of green hydrogen in Spain, expected to be operational by 2025.

According to the project's promoters, it is based on the integration of value chains, solar energy capture, industrial installation of electrolysers, deployment of exclusive pipelines for hydrogen transport and aggregation of energy demand, connecting large-scale renewable hydrogen production and its long-term profitable consumption. Thanks to it, renewable hydrogen will sustainably replace fossil fuels in industry, energy, and mobility.

The first stage of the project will supply an industrial complex in the Autonomous Region of Asturias, producing renewable hydrogen by electrolysis (for the time being, agreements have been signed to promote solar plants in Autonomous Region of Castilla y León).

The project is expected to have an installed capacity of 9.5GW, which will supply 7.4GW of power by 2030. Production is scheduled to start by the end of 2025, with the forecast to produce around 150,000 tonnes of renewable hydrogen per year from 2026, reaching 330,000 tonnes in 2030.

This green hydrogen will be used to advance the production of green steel, green ammonia, green fertilisers and other low-carbon industrial products. The plan is to sell 6.6 million tonnes of renewable hydrogen over the next 20 years, which would avoid 4% of Spain's current CO_2 emissions. This initiative will also contribute to Spain's energy independence, as it will supply the equivalent of 5% of imported natural gas.

According to internal sources, HyDeal Spain would be the first concrete implementation of the green hydrogen model with an estimated cost of €1.5 per kilogram (according to data from the International Energy Agency, the cost in July 2020 was between €3.5 and €5 per kilogram).

H.6 Smart cities

The Government approved the National Plan of Smart Cities in 2015 and, derived from its implementation, it approved in 2017 the National Plan of Intelligent Territories.

In general terms, the objective of the National Plan of Smart Cities was to contribute to the development of the technological industry in Spain. More specifically, it aimed to promote and help the economic development in the transformation procedure, helping to maximise the impact of the public politics, to improve productivity and competitiveness through the intense use of technology by society, businesses, and the Administration.

Its focus is on the following points:

- Increasing the contributions of information and communication technologies ("ICTs") to the GDP;
- Increasing the efficiency and efficacy of local entities in providing public services through the use of ICTs;
- Advance in the governance of the system of Smart Cities; and
- Promoting the standardisation and regulation of Smart Cities.

Red.es, a public entity which is pioneer in fostering and implementing the concept of 'smart cities' in Spain, carries out different activities within the context of the National Plan of Intelligent Territories, including certain actions aimed at improving tourists' experience in cities and at managing the information provided by internal objects in a city (such as buildings, airports, stations, ports, etc) for the optimisation of municipal services.

In the context of the National Plan of Smart Cities and the National Plan of Intelligent Territories, Red.es has promoted five tenders aimed at local entities which have allowed for up to 61 projects to be developed, mobilising in turn €200 million for Smart solutions. These tenders have been co-financed by the European Regional Development Fund (ERDF) and envisage technological measures with a value of €244,970,000, which will be under development until December 2023.

I. Environmental, social and governance (ESG)

Investor relations officers at leading Spanish companies generally perceive ESG issues to be more important than before the pandemic. Moreover, the gap between the importance that investors claim to give to ESG issues and the importance that investor relations departments perceive is gradually narrowing.

As a result, the main changes that are becoming apparent are as follows:

- more investors are opting for sustainable funds over those that do not take sustainability factors into account;
- more institutional investors are starting to demand a greater breakdown of ESG information;
- more investment funds are incorporating restrictions or exclusions in ESG terms;
- retail investors are becoming more aware of sustainable finance with the increase in the range of financial products available to them; and
- ESG issues are becoming more important for companies, regardless of their size.

Regarding the specific impact of ESG factors on energy investment, the interest of investors in climate change and taxonomy stands out. While in 2020 the most relevant issue was corporate governance, in 2022 climate change holds is considered to be the primary issue, followed by corporate governance, alignment with EU taxonomy, diversity and equality, ethics and corruption prevention, and eco-efficiency, in that order.

The use of sustainable financial products that finance the energy transition to sustainable development is expected to continue to grow. This will be supported by recently approved regulations, whose objectives include reducing GHGs, increasing the use of RES and improving energy efficiency.

In fact, the National Integrated Energy and Climate Plan 2021-2030 (PNIEC, by its Spanish acronym) has quantified an investment of more than €241 billion in the next decade in sustainable development projects oriented to the impact on the environment.

Another relevant fact that reflects the growing importance of ESG factors in energy investment is the growth in the issuance of green bonds in Spain, which among other things, help companies raise funds for the development of renewable energy projects, energy distribution and storage, and renewable gases.

In 2021, Spain moved up one position in the hierarchy of large global issuers of green bonds. Therefore, Spain became the seventh largest issuer of green bonds worldwide and the fourth largest in Europe.

Endnotes

1. Please note that the last modification made to Order ITC/3860/2007 allowed for companies to have a maximum of 2% of the total number of meters not replaced after 1 January 2019, provided that this was due to causes not attributable to them. Additionally, this failure to replace all meters had to be duly justified and approved by the CNMC. In this regard, as of 31 December 2019, compliance was close to 100%, but there were a few companies that had not reached the 98% threshold.
2. In accordance with RD 984/2015.
3. Under the Third Transitory Provision of RDL 13/2012.
4. By Royal Decree 335/2018, of 25 May, modifying various royal decrees that regulate the natural gas sector.
5. By Order TED/773/2020, of 23 July.
6. Boiling water reactor ("BWR"); pressure water reactor ("PWR").
7. Royal Decree Law 17/2019, of 22 November.
8. RD 960/2020.
9. RD 960/2020.
10. The Order originally established the indicative auction calendar for the period 2020-2025, but it was updated by means of Royal Decree 376/2022, of 17 May, to cover the period 2022-2026.
11. Amending Act 1/2005, of 9 March.
12. Amending Royal Decree 61/2006, of 31 January 2006.
13. Act 7/2021.
14. Further developed by Royal Decree 1494/2011.
15. Global warming potential of a GHG with respect to that of carbon dioxide, calculated in terms of the warming potential across one hundred years of one kg of GHG compared to that of one kg of carbon dioxide, as established in annex I of Regulation (EU) 517/2014.

Energy law in Sweden

Recent developments in the Swedish energy market

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Significant developments in the energy field

Expansion of renewable energy

Traditionally, the generation of energy in Sweden has mainly relied on hydro power and nuclear power. Sweden has set ambitious targets regarding the expansion of renewable energy generation, which has paved the way for a rapid transition of the energy market. Sweden reached its 2020 target of 50% renewable energy generation in 2012 and is now aiming for its 2040 target of 100% renewable energy generation.

During the last 10-15 years, wind power has gained increasing interest from energy generators and investors; the Swedish wind market is currently one of the largest in Europe. By the end of 2021, the installed wind power capacity was 12.2GW and the number of wind turbines was over 4,800. According to a forecast made by the Swedish Wind Energy Association, the rate of expansion may, however, slow down after 2024. This is in part due to a lack of granted permits, mainly in Sweden's southernmost bidding areas (SE3 and SE4).

Although solar power is still a minor power source in Sweden, it is on the rise and the number of grid-connected solar photovoltaic (PV) systems increased by about 50% between 2019 and 2020.

Some of the success of the increase of renewable power generation can be attributed to the Swedish electricity certificate system. The system is a market-based regime introduced in 2003 to support renewable energy generation. Through the system, generators of renewable energy are awarded electricity certificates for each generated megawatt hour, while generators of non-renewable energy are subject to quota obligations and must purchase electricity certificates to cover their quota. The system is now being phased out and will be completely shut down in 2035. No electricity certificates are issued for generation facilities commissioned after 31 December 2021.

Impact of the European energy crisis

The European energy crisis following Russia's invasion of Ukraine has had a substantial impact on Sweden. Although Sweden is minimally dependent on Russian energy supplies, the increased fossil fuel prices and their consequences on the European energy market has resulted in higher demand of Swedish electricity which has subsequently affected electricity prices in southern Sweden. The southern bidding areas' close connections to the European energy markets make these parts of the country more exposed to the situation in the neighbouring countries.

In addition, Sweden's southern bidding areas have less electricity generation than in the north, where most of the hydro generation facilities are located. Due to grid capacity constraints, the transmission of electricity from the north to the south is insufficient. This regional unbalance of energy supply has worsened following the closing of six nuclear reactors since 1999, all located in the south of Sweden, as well challenges to permits for new wind farms in the southernmost bidding areas.

Following the energy crisis, the issue of nuclear power has once again become a topic on the Swedish political agenda. The right-wing and conservative parties of the Swedish Parliament have stated that they wish to preserve and further develop nuclear power, following their win in the Swedish general election in September 2022.

Progress for offshore wind

Despite Sweden's notable position in the onshore wind markets, the offshore wind markets are less developed. Sweden's offshore wind generation amounts to only around 200MW and no new facilities have been built since 2013; however, over the last few months, the Swedish Government ("Government") has made important announcements regarding offshore wind, including promises to cover grid connection costs, identify areas suitable for the establishment of offshore wind farms, and pledges of substantial investments in the transmission grid.

Sweden currently lacks a regulatory framework specific for the planning of offshore wind sites. As the interest in offshore wind has increased, overlapping permit applications in the Swedish economic zone has become a topic. The Government is now planning to adopt a more centralised system for the identification and planning of offshore wind sites. The Government has assigned to the Swedish Agency for Marine and Water Management (*Havs- och vattenmyndigheten*) the task to investigate competing offshore wind farm projects. The authority shall look into a system for how different actors with competing applications are granted the exclusive right to establish offshore wind power in specific areas. The authority should report the results of the assignment no later than 30 November 2022.

In 2021, the Government requested that Svenska kraftnät, the Swedish Transmission System Operator (TSO), starts the preparations for the expansion of the transmission grid into the sea close to the exclusive economic zone to connect offshore wind farms. Offshore wind developers will only need to pay for the internal grids within the wind farms and the connections between the wind farms and the transmission grid connection points.

The pipeline of projects is susbstantial; in September 2022, offshore projects of around 30TWh had applied for permits. The Kriegers Flak offshore wind farm (640MW), owned by the state-owned company Vattenfall, is currently the only new project that has been granted a permit.

Decarbonisation and energy storage

The decarbonisation of Sweden's industry is key to Sweden meeting its target of achieving net-zero emissions of greenhouse gasses ("GHGs") in 2045. Sweden is considered by many to be a global leader in carbonising heavy industry and several private initiatives have gained international attention. One example is H2 Green Steel, which began construction of its first plant in Boden in August 2022. The plant in Boden aims to produce green steel by replacing coal with green hydrogen and therefore cutting carbon dioxide (CO_2) emissions by 95%.

Another exciting development is the growing industry of energy storages. Ellevio, one of Sweden's largest electricity network companies, recently announced its plans to construct Sweden's largest battery energy storage system (10MW) in Grums, western Sweden. Another example is Northvolt, which is a supplier of sustainable and high-quality battery cells and systems. With the support from leading automotive companies and global investment companies, Northvolt's first gigafactory in Skellefteå achieved the first assembly of a battery cell in December 2021. The aim for the gigafactory is to have a generation capacity of 60GWh.

Developments in government policy

Climate policy framework

In 2017, the Swedish parliament adopted a climate policy framework. The policy framework introduced a new climate act, ambitious climate targets, and a climate policy council. The Climate Act (*Klimatlag (2017:720)*) governs the Government's work regarding climate political issues and provides certain obligations which will apply to the current and future governments; among other things, the Government's climate policy must be based on the climate targets and the climate policy targets must work together with budget policy targets.

The adopted climate targets were the following:

- By 2045, Sweden should have zero net emissions of GHGs into the atmosphere. After 2045, Sweden should achieve negative emissions, meaning that the amount of GHG emitted is less than what can be reduced through the natural eco-cycle or through supplementary measures.
- By 2030, emissions from domestic transport should be reduced by at least 70% compared with 2010 (excluding domestic aviation).
- By 2030, emissions in Sweden in the sectors covered by the European Union ("EU") Effort Sharing Regulation (eg transport (excluding aviation and international shipping), building heating, agriculture and waste management) should be at least 63% lower than in 1990, out of which 8% may be achieved through supplementary measures.
- By 2040, emissions in Sweden in the sectors that will be covered by the EU Effort Sharing Regulation should be at least 75% lower than in 1990, out of which 2% may achieved through supplementary measures.

Proposal of changes to the environmental permitting process

One of the more pressing issues for Sweden in order to reach its environmental targets is to remove bottlenecks in the environmental permitting process and to make the procedure more effective. In June 2022, several actions were proposed with the purpose of facilitating environmental and climate-improving investments through changes in the environmental permitting and achieving faster and simpler assessment processes, while at the same time ensuring that environmental protection is maintained.

The proposal identified six main areas where improvements can be made to achieve the quicker and simpler permitting processes without decreasing the environmental protection, ie (i) simpler rules for changing operations, (ii) recurring review of permits and conditions in permits, (iii) clearer and more coordinated authorities, (iv) more active permitting authorities, (v) specific support for climate projects, and (vi) additional proposals for more effective permitting.

The proposals have received a mixed reception from the market and stakeholders of various kinds. On the one hand, there is a consensus that the permitting process needs to be improved, and the initiative was appreciated among most stakeholders. On the other hand, some have argued that the scope of the proposals is too narrow and that a complete reformation of the entire regulatory framework is required.

Proposal on new rules for foreign investments

In November 2021, a new mechanism for screening of foreign direct investments ("FDIs") was proposed. Under the proposal, foreign persons and entities looking to invest into activities within certain protected areas shall submit applications to the Inspectorate for Strategic Products ("ISP").

The sectors that are proposed to be subject to screening include: (i) essential services or infrastructure that are vital to society's basic needs or safety, (ii) security-sensitive activities set out in the Swedish Protective Security Act (*Säkerhetsskyddslag (2018:585)*), and (iii) activities that prospect for, extract, enrich or sell critical raw materials. It is likely that foreign investments in energy generation and infrastructure in many cases would be within the scope of the potential act.

FDIs may be prohibited by the ISP if it is necessary for Sweden's security or public order. In its assessment, the ISP shall consider the nature and scope of the activity and circumstances related to the investor, such as if the investor in any way is controlled by the government of another nation.

The proposal sets out a two-stage screening process. In the first stage, within 25 working days from a complete application the ISP shall decide to either take no further action or initiate an examination of the investment. If needed, the ISP may decide to examine the investment further as a second stage. In case of such further investigation, the general rule is that the authority must make a final decision within three months to approve or prohibit the investment. The ISP is entitled to approve the investment subject to certain conditions.

Tax relief for renewable energy

As of 1 July 2021, Sweden adopted new regulations allowing for tax relief for electricity that is generated via renewable energy sources (RES), such as wind, sun, or water, etc. Electricity generated from biofuel will also be subject to the tax relief.

Certain requirements apply for this tax relief to apply and the relief currently targets microproducers of electricity who generate electricity for their own use in facilities with a limited peak effect. However, given the current developments in the energy sector, we might see an extension of this relief to larger generators as well in order to stimulate a transition into renewable energy for larger businesses.

Notable mergers and acquisitions

Stockholm Exergi

In June 2021, Fortum sold its 50% stake in the district heating and cooling company Stockholm Exergi Holding AB to a consortium of European institutional investors, consisting of APG, Alecta, PGGM, Keva and AXA.

The total consideration of the sale amounted to SEK29.5 billion (about €2.9 billion based on the currency rate by the time of closing in September 2021).

Sale of OX2's stake in offshore projects

In August 2022, OX2 sold its 49% stake in three offshore wind projects in Sweden to Ingka Investments, the investment arm of Ingka Group. The three projects are Galatea-Galene, located off the coast of Halland, Triton, located off the coast of Skåne and Aurora, located off the coast of Gotland and Öland. The projects are under development and have the potential to generate up to 38TWh combined, which corresponds to more than 25% of Sweden's electricity consumption in 2021.

Overview of the legal and regulatory framework in Sweden

A. Electricity

A.1 Industry structure

Nature of the market

The Swedish electricity market underwent a major reform in 1996. Since 1996, the generation and trading of electricity has been deregulated and open for competition. The transmission and distribution of electricity are considered natural monopolies that are spread over the country.

Swedish electricity generation relies mostly on hydro power, nuclear power and wind power. During 2020, the total electricity generation amounted to 158.8TWh, of which hydro power accounted for 45%, nuclear power for 30% and wind power for 17%.

Key market players

The Swedish national grid is state-owned and operated by the Swedish Transmission System Operator ("TSO"), Svenska Kraftnät. The regional grids are owned and operated mainly by three companies: Vattenfall Eldistribution, Ellevio and E.on Elnät Sverige. The local grids are owned by private, state and municipal companies, or co-operative associations. There are currently around 170 grid operators on all levels in Sweden.

Swedish electricity generation is dominated by a few major players: Vattenfall (Swedish state-owned company), Fortum (Finnish state-owned company), E.ON (German company), Statkraft (Norwegian state-owned company) and Uniper (German state-owned company).

Regulatory authorities

The grid companies are supervised by the Swedish Energy Markets Inspectorate (*Energimarknadsinspektionen*), the authority that supervises compliance with the Swedish Electricity Act (*Ellag (1997:857)*). The Swedish Energy Agency (*Energimyndigheten*) is the Swedish Government ("Government") agency responsible for the supply and use of energy in Sweden. The Swedish Radiation Safety Authority (*Strålsäkerhetsmyndigheten*) is the governmental authority responsible for radiation protection. On the political level, the Ministry of Infrastructure is responsible for matters relating to energy.

Legal framework

Electricity transmission is a regulated activity that, as a general rule, requires a grid concession from the Swedish Energy Markets Inspectorate. Certain exemptions from the concession requirement apply, among other things, for internal grids that connect one or more generation facilities. Concessions are valid for an unlimited period unless revoked; however, if special circumstances apply, a concession may be limited to a period of 15 years. Grid concessions for international connections are granted by the Government.

To grant a concession, the concession must be appropriate from a general point of view and may be subject to certain conditions. These conditions usually protect public interests and individual rights, such as security, health and the environment.

Implementation of EU electricity directives

The EU Electricity Directives have been implemented in Sweden through the Swedish Electricity Act and associated regulations.

A.2 Third party access regime

Grid operators must, on objective, non-discriminatory and reasonable terms, connect an electrical installation to the grid if the owner of the electrical installation requests so. Exemptions from the obligation to connect others may be granted if there is a capacity shortage or other special circumstances apply. In certain parts of Sweden, grid capacity issues have been a bottleneck affecting the expansion and development of renewable energy sources (RES).

The Electricity Act does not stipulate any specific obligations for third party's connecting to the grid, but it is common for connections to be subject to the provision of financial security.

The fee for connection to the network must be designed so that the grid operator's reasonable costs for the connection are covered. The geographical location of the connection point and the agreed effect at the connection point must be considered. Minor generation units are exempted from the connection fee under certain circumstances.

A.3 Market design

As discussed in further detail above, in sections A.1 and A.2, the transmission of electricity is a regulated market that consists of natural monopolies. Electricity generation and trading has been deregulated and free since 1996.

The grid companies are under supervision by the Swedish Energy Markets Inspectorate, the authority that supervises compliance with the Swedish Electricity Act. The Swedish Energy Agency is the Government agency responsible for the supply and use of energy in Sweden.

Electricity transmission requires a grid concession from the Swedish Energy Markets Inspectorate. Certain exemptions from the concession requirement apply for, among other things, internal grids connecting one or more generation facilities. To be granted a concession, the concession must be appropriate from a general point of view and may be subject to certain conditions.

These conditions usually protect public interests and individual rights, such as security, health and the environment.

A.4 Tariff regulation

The Swedish Energy Markets Inspectorate determine revenue frames for the grid companies four years in advance, based on proposals from the grid companies. The revenue caps determine what the grid companies may charge their customers. The tariffs must be reasonable, objective and non-discriminatory and may cover the reasonable costs of operations and maintenance, and also allow for a reasonable return on grid companies' investments in order to attract capital for investments.

Upon determining the revenue frames, the Swedish Energy Markets Inspectorate takes into account the quality of the grid company's method of conducting network operations and the extent that the network operations are conducted in a manner that is compatible with, or contributes to, the efficient utilisation of the electricity network. The assessment affects the size of the revenue frame.

The Swedish Markets Inspectorate's application of the revenue frames has been criticised by the grid companies. On several occasions, certain grid companies have successfully disputed the Swedish Markets Inspectorate's application of the revenue frames.

A.5 Market entry

In addition to what is described above, in section A.1, there are no formal requirements for market entry.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

As mentioned, network operators must, on the basis of objective, non-discriminatory and reasonable terms, connect an electrical installation to the grid, if the holder of the electrical installation requests so. The transmission of electricity must be of good quality and the grid company must remedy deficiencies in the transmission to the extent that the costs of remedying the deficiencies are reasonable in relation to the inconvenience faced by the users.

A network operator must assign an electricity supplier if the customer does not actively choose one themself. The customer must be notified of the assigned supplier and the supplier must inform the customer of relevant terms and conditions.

Smart metering

Sweden was one of the first countries in Europe to begin using smart meters. The first regulation regarding smart meters was adopted in 2003. In 2018 and 2020, new functional requirements were introduced for low-voltage customers. Due to the new requirements, all electricity meters for low-voltage customers must be replaced by the network operators. The replacement must be completed by 1 January 2025 at the latest, and many network operators have already started replacing the meters.

Electric vehicles

In 2009, Sweden adopted a target for all vehicles to be fossil free by 2030. The number of registered electric vehicles in Sweden has increased significantly in recent years, amounting to around 100,000 by the end of 2021.

A.7 Cross-border interconnectors

In addition to the interconnections between Sweden and Norway, and Finland and Denmark, which are owned by the Swedish State and managed through the Swedish TSO, there are two connections connecting Sweden with another state, Baltic Cable and SwePol Link. These two connections are owned by Baltic Cable AB and SwePol Link AB respectively. Baltic Cable AB is owned by Statkraft Energy AS (Norway) and E.ON Sweden AB (Sweden). SwePol Link AB is owned by the Swedish State through Svenska Kraftnät and a Polish state-owned energy company, Polskie Sieci Elektroenergetyczne S.A. Although the basic rule is that the Swedish TSO is responsible for the transmission system and interconnectors are deemed to be part of the transmission system, the Baltic Cable is not owned by the Swedish TSO.

B. Oil and gas

B.1 Industry structure

Nature of the market

Sweden does not produce natural gas and is completely dependent on imports from Denmark. As such, the Swedish natural gas market is closely linked to the Danish market regarding supply, pricing and competition.

The Swedish natural gas network is small and comprises only 600km of transmission pipelines and about 3000km of distribution pipelines. The natural gas network is only located on the west coast in southern Sweden. In addition, there are minor urban and vehicle gas networks in the Stockholm region and other regions which are not connected to a transmission network. The total consumption of natural gas in Sweden amounted to 8.1TWh in 2020.

Key market players

The Swedish transmission system for gas is owned and operated by Swedegas AB, owned by European Diversified Infrastructure Fund (EDIF II) which is managed by Igneo Infrastructure Partners. Swedegas AB also has the responsibility to maintain balance in the gas transmission system.

Regulatory authorities

Swedish Energy Markets Inspectorate is the supervisory authority.

Legal framework

The Natural Gas Act (*naturgaslag (2005:403)*) includes provisions regarding natural gas pipelines, storage facilities and gasification facilities, as well as natural gas trading. As a general rule, natural gas pipelines, storage facilities or gasification facilities may not be built or operated without a concession from the Government. A concession may only be granted if the pipeline or facility is suitable from a general point of view and if the operator is suitable to conduct the operations. A concession may not be granted for a longer period than 40 years.

An application for a concession is submitted to the Swedish Energy Markets Inspectorate and must include, among other things, an environmental impact assessment ("EIA") (*miljökonsekvensbeskrivning*) in accordance with the Swedish Environmental Code (*miljöbalken (1998:808)*). A concession must be made conditional on the necessary conditions in order to protect public interests and individual rights as well as other conditions which are necessary for, among other things, safety reasons or to protect health or the environment.

Implementation of EU gas directives

The EU gas directives have been implemented in Sweden through the Natural Gas Act and associated regulations.

B.2 Third party access regime to gas transportation networks

The operator of a natural gas pipeline must connect other natural gas pipelines as well as storage facilities and gasification facilities on reasonable terms. Exemptions from the obligation to connect others may be granted if there is a capacity shortage or other special circumstances apply. An operator of a natural gas pipeline must also transport natural gas on reasonable terms, provided that the pipeline is not used only by the operator.

Fees and other terms for connection to the natural gas pipeline must be reasonable, objective and non-discriminatory. The geographical location of the connection point and the agreed effect at the connection point must be considered.

The same rules apply for liquefied natural gas ("LNG") as for natural gas.

B.3 LNG terminals and storage facilities

There are currently two Swedish terminals for LNG in operation, in Lysekil and in Nynäshamn. In addition, there are Swedish ports for liquefied petroleum gas ("LPG") in Karlshamn, Sundsvall, Piteå, Stenungssund, Gothenburg and Lysekil. LNG terminals are planned in several other locations in Sweden, including Gothenburg, Helsingborg and Gävle.

The Natural Gas Act also covers LNG (see sections B.1 and B.2 for a discussion on the regulatory framework).

B.4 Tariff regulation

Fees and other terms for the transportation and storage of natural gas and access to a gasification facility must be reasonable, objective and non-discriminatory. The conditions for the transportation of natural gas must consider the number of connected customers, the customers' geographical location, the quantity of energy transferred and subscribed effect, the costs of overhead lines, security of supply and pressure in the pipelines.

The Swedish Energy Markets Inspectorate determine revenue frames for the operators in advance for a period of four years. The revenue frames set an upper limit for the total revenues which companies may have from their natural gas operations. The limitations for the revenue are calculated so that reasonable costs for operating the business are covered and so that a reasonable return on the capital is possible. The natural gas company shall also make its fees and other terms public.

B.5 Market entry

As discussed in further detail in section B.1, natural gas pipelines, storage facilities or gasification facilities must not be built or operated without a concession from the Government. A concession must only be granted if the pipeline or facility is suitable from a general point of view and if the operator is suitable to conduct the operations.

An application for a concession is submitted to the Swedish Energy Markets Inspectorate and must include, among other things, an EIA (*miljökonsekvensbeskrivning*) in accordance with the Swedish Environmental Code (*miljöbalken (1998:808)*). A concession must be made conditional upon the necessary conditions in order to protect public interests and individual rights as well as other conditions which are necessary for, among other things, safety reasons and to protect health or the environment.

Under the Natural Gas Act, a company transporting natural gas must not trade in natural gas and an operator must be independent in relation to companies that produce or trade natural gas or electricity. The Natural Gas Act also prohibits individuals with control over a company (ie shareholders or representatives) that engages in the production or trade of natural gas or electricity, from having control over a pipeline operator.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

As aforementioned, the operator of a natural gas pipeline must connect to other natural gas pipelines as well as storage facilities and gasification facilities on reasonable terms. The operator must transport the gas on reasonable terms.

The owner of the natural gas pipeline must assign a gas supplier in the event that the customer does not actively choose one themself. The customer must be notified of the assigned supplier and the supplier must inform the customer of relevant terms and conditions.

Smart metering

Regarding the proposed amendments to the European Union ("EU") Gas Directive relating to new requirements on smart gas metering, the Energy Markets Inspectorate has emphasised that the Swedish gas market is relatively small and has warned that investments may be expensive for consumers. Nonetheless, the Energy Markets Inspectorate has an optimistic view of new requirements on smart metering, provided that the introduction of these requirements is suitable from a cost-benefit perspective.

B.7 Cross-border interconnectors

The sole interconnection is between Sweden and Denmark. The interconnector is Swedegas AB.

C. Energy trading

C.1 Electricity trading

Following the deregulation in 1996, electricity is traded on a free market that is open to new competitors. Physical trading takes place on a bilateral level, as well as on the Nord Pool spot market. Nord Pool includes Sweden, Finland, Norway, Denmark, Estonia, Latvia and Lithuania. Nord Pool was established in 1993 and is owned by the TSO of each state. Although the larger generators of energy participate in the market as both generators and traders (typically through in-house trading functions), most energy traders do not generate electricity.

On Nord Pool, electricity is traded per hour for delivery the following day. Nasdaq OMX, the Stockholm Stock Exchange, provides a futures market (financial trading) for long-term trade. In addition, traders may engage in long-term trading on a bilateral basis (often through brokers).

The Swedish TSO is responsible maintaining a balance between the generation and consumption of electricity in Sweden; however, the responsibility for ensuring that there is enough output to meet consumption falls to the balance-responsible parties ("BRPs"). Under the Electricity Act, an electricity supplier must supply as much electricity as its consumers consume. This responsibility may be assumed by the supplier itself or transferred to another company. This means that there is a BRP for each outtake and input point for electricity. The BRPs are typically generators, trading companies or major consumers.

Market coupling for the day-ahead market was made available in 2014 and is achieved through the Euphemia algorithm, an algorithm that was developed to solve the problem associated with the coupling of the day-ahead power markets.

C.2 Gas trading

Swedegas AB is the system balance administrator and enters into balance contracts with gas market participants called balance administrators. Since 2019, there has been an integrated balance market for natural gas between Denmark and Sweden. Natural gas was previously traded on the Danish gas exchange ETF PEGAS (previously Gaspoint Nordic). In 2020, ETF PEGAS was integrated into the European Energy Exchange ("EEX").

The EEX allows for trading on the same day as delivery, the day ahead, before the weekend, and before the next month. It is also possible to conduct long-term trading in futures (up to six years).

D. Nuclear energy

Nuclear energy represents about 30% of Sweden's total power supply. Sweden currently has three active nuclear plants: Forsmark, Oskarshamn and Ringhals, with a total of six operating reactors. Two reactors were closed in 1999 and 2005, respectively, and four reactors have been closed since 2017. The owners of the remaining nuclear plants are expected to continue operations until around 2040.

The issue of nuclear power has once again become a topic on the Swedish political agenda as a consequence of the on-going energy crisis. The right-wing and conservative parties of the Swedish Parliament have stated that they wish to preserve and develop nuclear power, following their win in the Swedish general election in September 2022.

Nuclear energy activities are regulated under the Nuclear Activities Act (*lag (1984:3) om kärnteknisk verksamhet*), including the construction, ownership and operation of a nuclear facility as well as any dealings with nuclear material and waste. The protection of people and the environment from harmful effects of radiation is regulated in the Radiation Protection Act (*Strålskyddslag (2018:396)*).

According to the Swedish Environmental Code, new nuclear energy activities must be approved by the Government. The Government must not approve a new nuclear reactor unless it replaces a nuclear reactor that has been in operation since 31 May 2005 and the new reactor is located at the same place as the previous nuclear reactor that has been operating since 31 May 2005.

Future costs relating to the disposal of spent fuel, decommissioning of reactors and research in the nuclear waste field is regulated in the Act on Financing Arrangements for the Disposal of Nuclear Waste (*lag (2006:647) om finansiering av kärntekniska restprodukter)*).

The Act on Liability and Compensation in the Event of Radiological Accidents (*lag (2010:950) om ansvar och ersättning vid radiologiska olyckor*) regulates liability for damages caused by accidents involving radioactive substances and the duty to contract insurance for such liability. Under this act, the owner of a facility has unlimited liability for radiological damage and must provide financial guarantees for compensation to those affected by a radiological accident. As a main rule, the owner must have a liability insurance or other financial security which covers €700 million, or €1.2 billion if the facility is a nuclear reactor.

In January 2022, Sweden adopted a plan to construct, possess and operate a facility for the final disposal of spent nuclear fuel. Together with Finland, Sweden was the first country in the world to adopt such a plan.

E. Upstream

Sweden does not currently produce oil and gas and therefore has no upstream regime in place.

F. Renewable energy

F.1 Renewable energy

The share of renewable energy of the total energy generation in Sweden is growing rapidly. Sweden reached its 2020 target of 50% renewable electricity generation in 2012. The target for the power sector is 100% renewable electricity generation by 2040. Hydropower and bioenergy are the most popular RES in Sweden, although the generation quantity from wind power has increased significantly since 2010. Although solar power is still a minor power source in Sweden, it is on the rise and the number of grid-connected solar photovoltaic (PV) systems increased by about 50% between 2019 and 2020.

The decarbonisation of Sweden's heavy industry is key to Sweden meeting its environmental targets. Several of these initiatives have gained international attention, eg Northvolt, which produces sustainable batteries and H2 Green Steel, which focuses on decarbonising Sweden's steel industry.

In 2003, a market-based electricity certificate system was introduced to support renewable energy generation. The system replaced previous public grants and subsidy systems. Through the system, generators of renewable energy are awarded electricity certificates for each generated megawatt hour, while generators of non-renewable energy are subject to quota obligations and must purchase electricity certificates to cover their quota. The electricity certificate system will be shut down in 2035. No electricity certificates are issued for generation facilities commissioned after 31 December 2021.

Sweden also has a system for guarantees of origin ("GO"), which are issued to generators of electricity as a certificate for where a generated megawatt hour was generated. The electricity generator can then sell the GO on an open market. The buyer is an electricity supplier that wants to sell the type of electricity that the generator generates. The electricity supplier will buy a GO corresponding to the amount of electricity that the supplier wants to sell.

It is generally considered that one of the more pressing issues in order to reach the 2040 target is to make the environmental permitting process more effective. In June 2022, the Government presented several actions with the purpose of facilitating environmental and climate-improving investments through changes in the environmental permitting and achieving faster and simpler assessment processes, while at the same time ensuring that environmental protection is maintained.

Another focus area is the work of the Swedish TSO to strengthen the Swedish transmission network with new lines and stations to incorporate new wind power and remove restrictions in the network. In 2021, the Government requested the Swedish TSO to start the preparations for the expansion of the transmission network into the sea, which will be needed to connect offshore wind farms.

F.2 Renewable pre-qualifications

There are currently no public auctions relating to renewables in Sweden. However, reversed auctions regarding carbon capture and storage ("CCS") are planned for 2023 (see section H.3).

F.3 Biofuel

The requirements on biofuel are regulated in the Act Concerning Sustainability Criteria for Biofuels and Bioliquids (*lag (2010:598) om hållbarhetskriterier för biodrivmedel och biobränslen*). Together with the Fuel Quality Act (*drivmedelslag (2011:319)*), the Renewable Energy Directive and the Fuel Quality Directive have been transposed to Swedish legislation. The Fuel Quality Act contains fuel specifications and reporting requirements imposed on fuel suppliers concerning supplied volumes, greenhouse gas ("GHG") emissions, and the origin of fuels.

The Swedish Energy Agency is the supervising authority for fuels, biofuels and bioliquids.

Through the Act on Reduction of Greenhouse Gases Emissions from Certain Fossil Fuels (*lag (2017:1201) om reduktion av växthusgasutsläpp från vissa fossila drivmedel*), fuel suppliers must reduce GHG emissions from the fuels that they supply by a certain percentage which increases each year (in 2022 this was 7.8% for petrol, 30.5% for diesel and 1.7% for kerosene).

G. Climate change and sustainability

G.1 Climate change initiatives

As discussed in section F.1, Sweden has set ambitious energy and environmental related targets and the share of renewable energy of the total energy generation in Sweden is growing fast. Sweden reached its 2020 target of 50% renewable electricity generation in 2012. The target for the energy sector is 100% renewable electricity generation by 2040.

One of the focus areas in order to reach the targets is to make the environmental permitting process more effective. In June 2022, the Government presented several actions with the purpose of facilitating environmental and climate-improving investments through changes in the environmental permitting and achieving faster and simpler assessment processes, while simultaneously ensuring that environmental protection is maintained.

Another focus area is the work of the Swedish TSO to strengthen the Swedish transmission network with new lines and stations to incorporate new wind power and remove restrictions in the network. In 2021, the Government requested that the Swedish TSO start the preparations for the expansion of the transmission network into the sea, which will be needed to connect offshore wind farms

Sweden is considered by many to be a global leader in energy storage and decarbonising heavy industry and several private initiatives have gained international attention, eg Northvolt which produces sustainable batteries, and H2 Green Steel, which focuses on decarbonising Sweden's steel industry.

G.2 Emission trading

The EU Emission Trading System ("EU ETS") has been implemented in Sweden mainly through the Emissions Trading Act (*lag (2020:1173) om vissa utsläpp av växthusgaser*). Under the Emissions Trading Act, companies covered by the emissions system must have a permit to emit GHGs. A valid permit is also a prerequisite for applying for the provision of emission allowances. The companies covered by the EU ETS must also monitor and report emissions. The monitoring must be in accordance with an approved monitoring plan, which must outline which emission sources are covered and how emissions are monitored.

Emission allowances may be traded on a trading exchange, via brokers or on a bilateral level. The trades are registered in the Swedish Emissions Trading Registry (*Svenskt utsläppsrättssystem* ("SUS")), which was established by the Swedish Energy Agency. There is no national additional trading scheme.

G.3 Carbon pricing

A carbon dioxide ("CO_2") tax was instituted in 1991, alongside an already existing energy tax, and it remains a cornerstone of Swedish climate policy. The tax is levied on all fossil fuels in relation to their emissions of CO_2 during combustion. The emission levels are dependent on the carbon content. The tax is highest on coal, then on oil and somewhat lower on natural gas.

The tax is collected by companies that provide fuel on the market. The administrative cost is very low as there are only a few, and generally large, companies that import fossil fuels. The cost is passed on to consumers through price mark-ups.

The Swedish carbon tax is the highest in the world. The tax rate has been increased from SEK0.25/kg in 1991 to around SEK1.20/kg in 2022. Sectors covered by the EU ETS, such as aviation, are excluded from the carbon tax.

G.4 Capacity markets

To ensure that there are sufficient automatic frequency restoration reserves ("aFRR") capacity, the TSOs of Sweden, Denmark, Finland and Norway have established a common Nordic capacity market. In May 2022, Sweden transitioned to the new IT platform which includes a new market design with daily auctions and marginal pricing. The aFRR balancing capacity is procured by each TSO before the day-ahead market, taking into account geographical distribution and network constraints. As available aFRR resources are unevenly distributed across the market, the TSOs will reserve some cross-zonal capacity for the aFRR capacity market in order to optimise socio-economic effects.

The Nordic capacity market cover of 12 bidding zones, five in Norway, four in Sweden, one in Finland and two in Denmark.

H. Energy transition

H.1 Overview

The energy transition is progressing well in Sweden. The 2020 target of 50% renewable energy generation was achieved with a margin; the actual share of the renewable energy generation by the end of 2020 was around 60%. Domestic transports reached a 32% level of renewable energy used, surpassing the 2020 EU target of 10%. The overall target for Sweden is to be climate neutral by 2050.

A rise in the use of biofuels accounted for the largest part of the increase of renewables, which mainly occurred in the industrial and transport sectors. The growth of wind power was the second largest reason for the increase in renewable energy, followed by the use of heat pumps. Sweden has also been successful in energy management; the ultimate energy consumption decreased from 413 to 396TWh between 2005 and 2020, despite Sweden's population increasing by almost 1.4 million.

Some of Sweden's more important initiatives relate to the reformation of the environmental permitting process with the purpose of facilitating environmental and climate-improving investments and achieving faster and simpler permitting processes, as well as the strengthening and the expansion of the Swedish transmission grid.

H.2 Renewable fuels

Hydrogen

Sweden has previously not had an elaborate strategy for hydrogen or ammonia. The Government recently launched an initiative called 'Fossil free Sweden', through which a hydrogen strategy was presented in 2020. That strategy laid the groundwork for the formal strategy launched by the Swedish Energy Agency in 2021. The strategy covers hydrogen, electrofuels and ammonia.

The strategy establishes specific goals for 2030 and 2045 and identifies several actions and initiatives to implement, including additional assessment as regards new control instruments which reduce the cost gap between fossil hydrogen and fossil free hydrogen. The strategy also proposes to establish a platform for systematic dialogue between companies, industry organisations and public actors.

There are a number of major industrial projects in Sweden, where the production and use of hydrogen is, or is planned, to be a central part of the value chain.

Ammonia

The aforementioned hydrogen strategy also covers ammonia.

H.3 Carbon capture and storage

To achieve the target of negative emissions of GHGs following 2040, CCS will play an important role. The Energy Agency has been appointed as the national centre for CCS, which means that it is responsible for planning and enhancing cooperation and to promote the use of CCS in Sweden.

The Energy Agency has been instructed to make possible the export of separated CO_2 to storage units in other countries, eg Norway. In order to do so, a bilateral storage agreement must be entered into with Norway, which must comply with the London Convention on the Prevention of Marine Pollution by Dumping of Wastes and Other Matter.

The CCS technique is not yet commercially viable and state support is needed to continue its development. A support system has been established, under which the Energy Agency will conduct so called 'reversed auctions', meaning that players can make bids on how much CO_2 they can separate and store and to what cost. The bidder that delivers CCS in the most cost-efficient manner wins the auction. The first auction was initially planned to take place in 2022 but has been postponed until 2023.

H.4 Oil and gas platform electrification

There are currently no oil and gas platforms in Sweden.

H.5 Industrial hubs

Besides local initiatives, there are currently no plans to introduce industrial hubs in Sweden.

H.6 Smart cities

Although there are no firm plans for specific smart cities in Sweden, individual initiatives and business ideas are developed and promoted. Local projects with the ambition of creating smart cities or neighbourhoods exist and have proven to be successful on a smaller scale.

Smart City Sweden is a state-funded initiative with the main purpose of promoting the development and export of smart and sustainable city solutions. The focus areas of Smart City Sweden are mobility, energy, the climate and environment, urban planning, digitalisation and social sustainability.

I. Environmental, social and governance (ESG)

Sustainability is becoming increasingly important for market players and market research suggests that some investors will completely stop investing in 'non-ESG' assets within the coming years. Many investors have adopted internal ESG policies under which they must consider and promote ESG aspects during each step of the investment process, including due diligence, management and exit.

ESG aspects have been introduced to the Swedish energy market through the system for GO (see section F.1, for additional information on the system). The GO is a way for electricity suppliers to eco-label their renewable energy and to prove where it comes from.

Energy law in Switzerland

Recent developments in the Swiss energy market

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Energy Act

On 1 January 2018, the revision of the Energy Act and, hence, a first set of measures under the Swiss Federal Council's, 'Energy Strategy 2050', entered into force to promote the generation of renewable energy, increase energy efficiency, and initiate the exit from nuclear energy:

- the generation of renewable energy shall be promoted by simplifying the authorisation process to construct renewable energy generation facilities and investment subsidies;
- in order to increase energy efficiency, the refurbishment of buildings to improve energy efficiency has been incentivised (eg, through tax benefits), the targets for the average carbon dioxide ("CO_2") emission of imported cars have been lowered, and the fee on CO_2 emissions has been increased; and
- in order to initiate the exit from nuclear energy, permissions to construct new nuclear power plants will not be granted.

Draft of the new Federal Act on a Secure Electricity Supply with Renewable Energies

In June 2021, the Federal Council released the draft of the new Federal Act on a Secure Electricity Supply with Renewable Energies (SESA) and the related report. With this bill, which includes a revision of the Electricity Supply Act and the Energy Act, the Government aims to set binding targets for renewable energy for 2035 and 2050 and for the reduction of the energy consumption per head. These targets are as follows:

- revise and increase the incentives to promote renewable energy;
- secure a long-term electricity supply for winter;
- achieve full liberalisation of the electricity market (currently, the market is only liberalised for customers with an annual consumption of at least 100,000kWh); and
- increase the cost efficiency of the utilisation and expansion of the electricity grid.

As of December 2022, the proposal has not been debated by Parliament. However, due to the energy crises (see below), the Federal Council (government) issued several ordinances implementing certain elements of the SESA already on 1 October 2022 and 1 January 2023. Further, the parliament approved certain changes to the Energy Act as of 1 January 2023.

The Federal Act on the Reduction of CO_2 Emissions

On 13 June 2021, the total revision of the Federal Act on the Reduction of CO_2 emissions ("CO_2 Act") was rejected in a federal vote. On 17 December 2021, the Federal Council issued a draft of a partial revision of the CO_2 Act and the related report. The main targets and measures of the partial revision are to:

- cut emissions of greenhouse gases in half by 2030, as compared with 1990 levels;
- extend the duration of the CO_2 Act beyond 2024 (its current limitation date);
- continue the current CO_2 fee (currently, a fee of CHF120 per tonne of CO_2 is charged on the import of carbon-based fuels); and
- incentivise the reduction of greenhouse gases (via energy efficient renovation of buildings, implementation of charging infrastructure for electric vehicles, etc).

Exit from nuclear energy

One of the principal goals of the Swiss Energy Strategy 2050 is to initiate the exit from nuclear energy by decommissioning existing nuclear plants at the end of their lives and prohibiting new nuclear power plants. Because of the energy crises (see below), political discussions have started whether new nuclear facilities shall be permitted again.

Sectoral agreement with the EU

The Federal Council intended to enter into a bilateral agreement with the EU for the energy sector. However, it has become unlikely that such an agreement will be concluded in the near future as Switzerland broke off the negotiations with the EU on an institutional framework agreement in May 2021.

Gas Supply Act

In 2019, the Federal Council proposed a draft Federal Gas Supply Act ("the Act") to facilitate the development of an efficient gas market in Switzerland. The Act has been referred to Parliament for discussion. The Act would remedy the current situation, in which the Swiss Competition Commission ("ComCo") has forced a liberalised gas transmission market on the basis of the Cartel Act. Due to the ComCo's intervention, there is no standard legal framework to ensure effective competition. In these circumstances, there are currently different conditions for the supply of gas. This affects, for example measurements or forecasts and the balancing of supply and consumption.

Energy crises

Due to the energy crises resulting from Russia's invasion of Ukraine, the Swiss Federal Council, the Cantons, and the electricity and gas industry have proposed various measures or have already decided on certain measures. The approved measures comprise:

- the operators of hydroelectric plants must increase their water reserves;
- increase of the capacities of certain hydroelectric power plant;
- measures to accelerate the approval process for the construction of renewable energy power plants (in particular solar and wind power plants);
- the gas suppliers and distributors may (disregarding competition law) coordinate the acquisition of gas reserves and gas storage capacities;
- a voluntary gas consumption reduction by 15%;
- a campaign to reduce the private consumption of gas and electricity; and
- a preparation of emergency measures.

The following measures are being prepared:

- support of reserve electrical plants (operated with oil);
- cooperation agreements with Germany, France, and Italy; and
- preparation of financial support to critical electricity providers in case of crises.

Overview of the legal and regulatory framework in Switzerland

A. Electricity

A.1 Industry structure

Nature of the market

There is only one national high-voltage transmission system operator ("TSO"): Swissgrid AG ("Swissgrid"). It has exclusive rights to the transmission network in Switzerland, operating a 6,700km long high-voltage grid (voltage levels of 380kV and 220kV) to transport electricity from the generating stations to regional and local distribution systems via the transmission system. Swissgrid is owned by a different state – with privately-owned generators and utility providers. Otherwise, the Swiss market for the generation, distribution, and supply of energy is highly fragmented due to the autonomy of the Cantons. There are about 630 electricity supply companies and local distribution system operators ("DSO") active in Switzerland. Nearly 90% of electricity supply companies are owned by the Swiss Confederation, the 26 Cantons, or the municipalities. The Swiss electricity market is liberalised for end users with an annual consumption of at least 100MWh.

Key market players

The players in the electricity market vary substantially in terms of size, organisational form, and scope of activities. There are a number of fully vertically integrated utility companies that cover the entire value chain, beginning with energy production in power plants and ending at the low-voltage supply grid. Many municipalities provide electricity, water, gas, and district heat through their own local DSOs. Most of them do not produce energy. Larger cities own power plants and produce small amounts of energy. The major producers of electricity are:

- Axpo Group, owned by Cantons as well as public utilities;
- Alpiq Group, owned by public utilities and private investors;
- Repower AG, owned by Cantons, public utilities and private investors;
- BKW Energie AG, owned by the Canton of Berne and private investors (shares are publicly listed); and
- Elektrizitätswerke des Kantons Zürich (EKZ) and Elektritätswerk der Stadt Zürich (EWZ), independent institutions of the Canton of Zurich and of the City of Zurich.

These companies produce most of the nuclear and hydro energy generated in Switzerland at their power plants. Additionally, they own a considerable part of the distribution network.

Regulatory authorities

The main regulatory authority in energy matters is the Swiss Federal Office for Energy ("SFOE"), a division of the Federal Department of Environment, Transport, Energy, and Communications ("DETEC"). SFOE acts as the competence centre for issues relating to energy supply and usage and ensures the maintenance of high safety standards in the production, transport, and utilisation of energy.

The Swiss Electricity Commission ("ElCom") monitors compliance with the Federal Electricity Supply Act ("ESA") and parts of the Energy Act ("EA"), taking all necessary related decisions and issuing rulings where required. It monitors the development of the electricity supply to secure safe and affordable energy. Furthermore, ElCom also oversees the status and maintenance of the Swissgrid transmission network. ElCom also acts as a judicial body in certain disputes relating to matters such as network access.

The Federal Inspectorate for Heavy Current Installations ("ESTI") is responsible for the technical supervision and inspection of electrical installations and ensuring their safe maintenance.

The Federal Nuclear Safety Inspectorate ("ENSI") is the regulatory body responsible for the safety of Swiss nuclear facilities, in particular the nuclear power plants.

Legal framework

Under Article 89 of the Swiss Federal Constitution, the Confederation, and the Cantons must secure a sufficient, broadly diversified, safe, economical, and environmentally friendly energy supply. The Confederation is responsible for establishing the general principles on the use of domestic and renewable energies, the regulation of nuclear energy, the definition of principles pertaining to hydropower generation, and the legislation on transmission and distribution of electricity. The Cantons are responsible for all other matters.

Numerous acts and ordinances apply on a federal level. These include:

- Federal Act on Energy of 30 September 2016 (*Energiegesetz*);
- Ordinance on Energy of 1 November 2017 (*Energieverordnung*);
- Ordinance on the Energy Efficiency Requirements of Mass-produced Systems, Vehicles and Appliances of 1 November 2017 (*Energieeffizienzverordnung*);
- Ordinance on the Promotion of Electricity Generation from Renewable Energies of 1 November 2017 (*Energieförderungsverordnung*);
- Federal Act on the Reduction of CO_2 of 23 December 2011 (*CO_2-Gesetz*);

- Ordinance on the Reduction of CO_2 Emissions of 30 November 2012 (*CO_2-Verordnung*);
- Federal Act on Electricity of 24 June 1902 (*Elektrizitätsgesetz*);
- Ordinance on Low Voltage Utilities of 30 March 1994 (*Schwachstromverordnung*);
- Ordinance on High Voltage Electricity Utilities of 30 March 1994 (*Starkstromverordnung*);
- Ordinance on Electric Lines of 30 March 1994 (*Leitungsverordnung*);
- Federal Act on Electricity Supply of 23 March 2007 (*Stromversorgungsgesetz*);
- Ordinance on Electricity Supply of 14 March 2008 (*Stromversorgungsverordnung*);
- Federal Act on Nuclear Energy of 21 March 2003 (*Kernenergiegesetz*);
- Ordinance on Nuclear Energy of 10 December 2004 (*Kernenergieverordnung*);
- Federal Act on Utilisation of Water Power of 22 December 1916 (*Wasserrechtsgesetz*); and
- Federal Act on the Protection of Waters of 24 January 1991 (*Gewässerschutzgesetz*).

In addition, a wide range of cantonal laws apply, such as the Cantonal Energy Acts and the Cantonal Acts on Utilisation of Water Power. These partly implement federal legislation and partly contain provisions which are independent from federal law.

In 2011, the Swiss Federal Council and the Swiss Parliament decided that Switzerland should cease its production of nuclear energy. As a result, the Energy Strategy 2050 was developed, and the EA was enacted on 1 January 2018. The goals of the EA are to increase energy efficiency and promote renewable energy sources ("RES"). From 1 January 2018, the construction of new nuclear power plants and fundamental modifications to existing nuclear power plants will not be approved. Furthermore, the ESA was partially revised as of 1 June 2019.

Implementation of EU electricity directives

Switzerland is not a member of the European Union ("EU") and therefore is not required to implement EU electricity directives unless expressly agreed with the EU. Switzerland has been negotiating a bilateral agreement with the EU in the electricity sector since 2007. In May 2021, however, Switzerland broke off negotiations with the EU of an institutional framework agreement. Consequently, an electricity agreement will not be reached for the foreseeable future and Switzerland will continue to not be bound by the EU electricity directives.

A.2 Third party access regime

Companies (including generators, traders, and eligible consumers) must enter into network access agreements with Swissgrid to access the transmission grid. Each network access agreement must be allocated to a specific balancing group (established by balancing agreements) within a balancing zone. The balancing agreements with the generators, importers, traders, or suppliers of electricity determine the terms and conditions of the entry and exit of electricity at the entry and exit points in order to maintain a stable network.

End consumers with an annual consumption of at least 100MWh per year are free to choose their electricity supplier. Local DSOs must grant non-discriminatory access to their distribution networks, thus enabling the supply of electricity by third party suppliers. Local DSOs have a monopoly for supplying electricity to end customers consuming less than 100MWh per year.

A.3 Market design

Swissgrid has an operation monopoly over the Swiss transmission network and acts as the sole TSO. Whilst there is no competition pertaining to the distribution of electricity due to the natural monopolies of the local DSOs, numerous companies compete in the electricity production and supply markets.

A.4 Tariff regulation

Transmission and distribution tariffs are set by Swissgrid and the respective local DSOs each year and are cost-based. Swissgrid and the local DSOs must consider the cost of constructing, operating, and maintaining the transmission and distribution networks. The overall tariff includes a working tariff per kWh, a power tariff per MW, and a fixed base tariff per exit point. In addition, Swissgrid and the local DSOs can charge for general and individual ancillary services.

ElCom monitors the tariffs set by Swissgrid and the local DSOs, however, the tariffs are not subject to ElCom's approval. ElCom has the power to order tariff reductions and oversee disputes concerning remuneration for the network use. ElCom frequently uses its power to review and reduce the tariffs set by Swissgrid and the local DSOs. The decisions of ElCom can be challenged before the Federal Administrative Court.

Tariffs for the supply of electricity to end consumers that do not obtain electricity from a third-party supplier but from their local DSO are also regulated. They are based on the prime costs of efficient production and on the local DSO's long-term electricity procurement contracts.

A.5 Market entry

The approval process for the construction and operation of a power generation facility depends on the type of such facility and the location (ie, the Canton). The competent authority assesses the safety and the impact of the project on the environment and the local community. The process usually includes a public consultation and any approval granted can be challenged in court.

The basis for the construction of transmission lines is in the federal sectoral plans. The Federal Council approves requests for inclusion in the federal sectoral plans. The permit of a specific project must be obtained from ESTI. ESTI assesses the project's compliance with safety regulations as well as environmental and spatial planning laws. Parties affected by the project can raise objections which are overseen by the SFOE. Decisions of the SFOE can be challenged before the Federal Administrative Court. The entire approval process can take several years.

The approval process for the construction of a distribution facility depends on the type of facility and its location (ie the Canton) but is generally similar to the approval process for transmission lines, albeit shorter. All high-voltage facilities must be approved by ESTI but no sectoral plan approval is required.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Local utilities (ie, local DSOs) must supply electricity to all local end users that do not obtain electricity from a third-party supplier. Tariffs must be reasonable and fixed on an annual basis (see section A.4).

Smart metering

The Ordinance on Electricity Supply requires the installation of smart meters and determines the specifications of such meters. By the end of 2027, 80% of all meters must be smart meters.

Electric vehicles

There are several measures designed to increase the use of electric transport and reduce CO_2 emissions, for example various tax benefits. Since 1 January 2021, the average CO_2 emission of new cars must not exceed 118 grams of CO_2 per km (measured in accordance with the Worldwide Harmonised Light Vehicle Test Procedure ("WLTP")).

The DETEC introduced the 'Roadmap for Electric Mobility 2025' to increase electric mobility, for example by developing a widespread quick-charging network. The Roadmap's goal is to increase the quantity of new vehicles that are 100% electric to 50% of all cars by 2025

A.7 Cross-border interconnectors

Switzerland's transmission network is connected to the networks of Austria, France, Germany, and Italy via about 40 connections. Imports from France usually amount to half of Switzerland's total energy imports. Imports from France and Austria exceed exports to these countries. Exports to Italy usually amount to around two-thirds of total exports, thus exceeding imports from Italy. In the past, imports from Germany exceeded exports, but this has since been reversed. As outlined, Swissgrid is the exclusive Swiss transmission network operator, with the exception of some cross-border transmission lines that do not fall under this monopoly. These lines can be owned by other parties and are not controlled by Swissgrid.

Capacity shortages in the cross-border network must be managed by allocating network capacities in a market-oriented allocation procedure. Capacities are, therefore, usually allocated yearly, monthly, and daily as well as through intraday auctions. The auctions are usually managed by the Allocation Office JAO S.A. which acts as the auction platform in Europe.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Switzerland does not have any oil. The oil market is free from any state involvement and is completely liberalised, except for the requirement of an import licence. An import licence triggers the requirement to enter into a stockpiling agreement. Under the Federal Act on National Economic Supply, the supply of vital goods and services to the Swiss population must be ensured in cases of disruptions. Compulsory stocks are maintained for this purpose and procedures are prepared for using these stocks when supplies are low, alongside other control measures. The Federal Department of Economic Affairs, Education and Research ("EAER") establishes the quantities that must be compulsorily stockpiled per product category, following consultations with the oil industry. The stockpiling is supervised and coordinated by CARBURA, an organisation of importers of liquid fuels and combustibles for compulsory stockpiling. CARBURA allocates the overall obligation under the compulsory stockpiling programme for the individual products. This is subject to compulsory stockpiling within the product categories according to the EAER ordinance. Compulsory stockpiles must in principle be maintained by importers, ie, by market players themselves. The quantities to be compulsorily stockpiled by individual members are based on their import quota over the last three calendar years. This calculation is reviewed annually.

Oil is imported by tanker (by road, water, and rail) or by pipeline. Switzerland procures oil mainly from Nigeria, the United States of America and Libya.

Key market players

The key market players in the oil market are multinational oil companies (wholesale trade) and multiple smaller distribution companies. Only one company imports and refines crude oil in Switzerland, all other oil products are processed before import.

Regulatory authorities

Aside from the import licence and compulsory stockpiling requirement, the oil market is fully liberalised. Mandatory stockpiling is established by EAER and the construction and operation of pipelines is subject to the authorisation of SFOE.

Legal framework

The following acts and ordinances apply on a federal level:

- Federal Act on Pipelines for the Transport of Liquid or Gaseous Fuels ("Federal Act on Pipelines") (*Rohrleitungsgesetz*);
- Federal Ordinance on Pipelines for the Transport of Liquid or Gaseous Fuels ("Federal Ordinance on Pipelines") (*Rohrleitungsverordnung*); and
- Ordinance concerning Safety Standards for Pipelines (*Verordnung über Sicherheitsvorschriften für Rohrleitungsanlagen*).

The Federal Act on Pipelines governs the supervision, construction, and operation of pipelines. In particular, the construction of a pipeline requires an environmental impact assessment.

Smaller pipelines do not require the authorisation of SFOE but are supervised by the Cantons and any approval requirements are determined by federal law.

Gas

Nature of the market

Switzerland does not produce any gas (except for a minor amount of biogas). Gas is imported by tanker (by road, water, and rail) or by pipeline. Switzerland procures gas mainly from Russia, Norway, and the EU.

Generally, local gas distributors have a natural monopoly because of their distribution networks. The Federal Act on Pipelines requires high-pressure pipeline operators to carry out transit operations for third parties, provided the transport is technically possible, economically reasonable, and an adequate fee is paid. Additionally in 2020, ComCo decided that any refusal by network owners to provide access to third party gas suppliers would be considered an infringement of the Cartel Act. Consequently, ComCo imposed financial sanctions on one of the network owners, indirectly liberalising the Swiss gas market. To date, however, no legal framework exists to ensure effective competition in the market. The planned Federal Gas Supply Act would fill this gap.

Key market players

The major players in the gas market are Erdgas Ostschweiz AG, Erdgas Zentralschweiz AG, Gasverbund Mittelland AG, and Gaznat S.A.. These four companies founded Swissgas AG (ie Swissgas) to procure natural gas for Switzerland on a non-profit basis. Swissgas operates four high-pressure pipelines that connect the transit gas pipeline to various regions.

The transit pipeline running through Switzerland, which is part of the Netherlands-Italy pipeline, is operated by Transitgas AG, in which Swissgas holds a 51% share (the remainder is held by FluxSwiss S.A. (46%) and Uniper Global Commodities SE (3%)).

The regional high-pressure network is operated by various gas suppliers. These suppliers entered into a private associations' agreement in 2012 to regulate third-party access (including remuneration).

Other than the key players, there are about 100 regional or local gas suppliers of different sizes who own the regional pipeline system and are usually owned by the public.

Regulatory authorities

As established above, there is no regulatory body governing the gas market in Switzerland, with the exception of the oversight of SFOE under the Federal Act on Pipelines and of ComCo under the Cartel Act.

Legal framework

- The same legal framework applies as for oil (see above).

Other than the Federal Act on Pipelines, only the current associations' agreement between the gas suppliers regulates the market. This is not in line with the European market regulation as it does not provide for a regulator. Furthermore, the Cartel Act is applicable to the gas market. On this basis, certain refusals to supply access, as well as discriminatory or bundling strategies, and so on, could be declared unlawful by the ComCo and financial sanctions could be issued.

Foreign companies can supply gas directly to Swiss consumers connected to the regional high-pressure network. The SFOE acts as judicial authority for disputes in relation to third-party access to the high-pressure network.

Implementation of EU gas directives

The EU gas directives are not implemented in Switzerland as Switzerland is not an EU member state.

B.2 Third party access regime to gas transportation networks

Under the Federal Act on Pipelines, the operators of major pipelines must execute transit operations for third parties, provided the transport is practically and economically reasonable, and an adequate fee is paid.

The SFOE is the judicial body for disputes in relation to third party access, particularly regarding pricing. In general, the prices are determined by the suppliers (usually the Canton or the municipality).

B.3 LNG terminals and storage facilities

Switzerland does not have any LNG terminals. The gas companies Gaznat and GVM have a natural gas storage facility located in France (representing about 5% of the annual gas consumption in Switzerland). Emergency access has been secured through an agreement between Switzerland and France.

B.4 Tariff regulation

There is no federal regulation determining gas prices. Gas suppliers set the prices in accordance with local law. Generally, the gas price comprises of a base tariff, a working price per kWh, and an output price per kW. There are substantial differences in the prices depending on the area. Hence, gas prices as well as gas network usage prices have been subject to regular monitoring investigations by the Swiss Price Surveillance Authority.

All gas supply tariffs have been collected since 2011 and published on gaspreise.preisueberwacher.ch.

The oil market is liberalised (except the mandatory stockpiling and the petroleum taxes), and the prices are not regulated.

B.5 Market entry

The existing pipelines are owned by state-controlled entities and therefore, are not for sale. The construction of new pipelines would require access to land (servitudes or own land) which is generally not available. Hence, there are significant entry barriers into the gas market, except via the third-party access regime established above.

The oil market does not generally depend on pipelines for local distribution and is liberalised. Consequently, there are limited barriers to entering the oil market.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

There are no PSOs of gas or oil suppliers.

Smart metering

There is no regulation requiring the implementation of smart metering technology.

B.7 Cross-border interconnectors

As Switzerland does not produce gas or oil, it depends entirely on imports for these products (except for minor amounts of biogas). Oil and gas are either procured by tanker (by road, water, and rail) or by pipeline. The access to cross-border pipelines is not regulated, other than the provisions which apply to domestic pipelines (see section B.2).

C. Energy trading

C.1 Electricity trading

The key market players (see section A.1) are active in the European energy trading markets. Switzerland does not have its own power exchange platform. The key market players trade electricity as well as financial products.

C.2 Gas trading

The key market players (see section B.1) are active at foreign exchanges such as the EEX. Switzerland does not have its own gas exchange platform.

D. Nuclear energy

Under the Swiss Constitution, the Confederation is exclusively responsible for legislation in the field of nuclear energy. The main act is the Nuclear Energy Act, and the main ordinance is the Nuclear Energy Ordinance. They regulate the construction and operation of nuclear power plants.

Nuclear energy supplies around 33% of Swiss electricity. The four active nuclear power plants in Switzerland are Gösgen, Leibstadt, Beznau I and Beznau II (constructed between 1969 and 1984).

Under the Energy Strategy 2050 (adopted in 2012), all nuclear power plants must be decommissioned after they reach the end of life (between 2030 and 2045). Since 1 January 2018, the construction of new nuclear plants or material changes to existing nuclear plants are prohibited.

The decommission of a nuclear power plant requires SFOE to approve the operator's decommissioning project. Anyone who is affected by the decommissioning may challenge the approval with the SFOE, which then drafts a decommissioning order for the attention of the DETEC. The decommissioning of the first Swiss nuclear plant (Mühleberg) started on 6 January 2020 and will be completed by 2034.

E. Upstream

There is no exploration, drilling or extraction of oil and gas in Switzerland.

F. Renewable energy

F.1 Renewable energy

The Energy Strategy 2050, introduced in 2009, is the main Swiss initiative designed to promote renewable energy via measures such as a feed-in remuneration system. No new facilities, however, are currently being accepted into the system. Developers can apply for investment contributions for certain renewable energy production installations. A variety of additional public sector support measures and regulations exist on cantonal and municipal levels to promote the use of renewable energy.

The Federal Council has proposed a new Federal Act on a Secure Electricity Supply with Renewable Energies ("SESA") and a revision of the Federal Act on the Reduction of CO_2 Emissions ("CO_2 Act") to further encourage the development of renewable energies. The SESA and the revisions of the CO_2 Act have not to date been finalised. The end goal is that the basic supply of energy will come entirely from RES.

Hydropower generates about two-thirds of Switzerland's electricity production.

F.2 Renewable pre-qualifications

There are currently no renewable pre-qualifications in place in Switzerland.

F.3 Biofuel

Biofuels are currently exempted from the petroleum tax. The exemption is in place until 31 December 2023.

G. Climate change and sustainability

G.1 Climate change initiatives

The Swiss Federal Council's Energy Strategy 2050 is the main climate change initiative in Switzerland. The strategy comprises three strategic objectives:

- increase energy efficiency;
- increase the use of renewable energy; and
- initiate the exit from nuclear energy. The overall objective is the reduction of CO_2 emissions.

The key legislative act of the Swiss climate policy is the CO_2 Act. With the ratification of the Paris Agreement, Switzerland has committed to reducing greenhouse gas ("GHG") emissions by 50% by 2030, as compared with 1990 levels. The reduction of CO_2 emissions shall be achieved through various measures. For example, since 1 January 2021, the average CO_2 emission of new cars must not exceed 118 grams of CO_2 per km (measured pursuant to WLTP). If this amount is exceeded, the importer must pay fines for each vehicle put into circulation of up to CHF152 per gram of CO_2 emission exceeding the maximum. Furthermore, the CO_2 Act introduced a fee on carbon-based fuels (currently CHF120 per tonne). Additional measures include the introduction of emission trading and incentives for the energy saving refurbishment of buildings.

G.2 Emission trading

The CO_2 Act provides for a national emission trading system ("ETS"). The ETS is a quantity control instrument which applies the 'cap-and-trade' principle. It specifies a maximum amount of newly available emission allowances in the system (the 'cap') that is reduced each year. Some of the emission allowances are allocated free of charge, and some are auctioned. Each year, participants in the ETS must cover their emissions with emission allowances. These emission allowances can be traded freely and can be used to cover their own emissions or sold to other ETS participants (who do not have sufficient allowances). The Federal Office of Environment calculates the number of emission rights each individual ETS participant receives free of charge. This allowance is determined using benchmarks. Most of the benchmarks are defined as a number of emission allowances per tonne of product or terajoule of heat used and correspond to the emissions of a GHG-efficient production facility. Participants in the ETS do not have to pay the CO_2 fee.

It is compulsory for installation operators with high GHG emissions to participate in the ETS (ie, ETS participants). Activities that generally cause high to very high emissions are listed in the CO_2 Ordinance (Appendix 6). Any company which carries out such an activity must participate in the Swiss ETS. Sectors affected include cement, chemicals and pharmaceuticals, refineries, paper, district heating, and steel.

Flights within Switzerland and from Switzerland to the European Economic Area (EEA) have been subjected to the Swiss ETS since 2020. Aircraft operators must surrender emission allowances in the amount of CO_2 emissions from these flights.

Emission allowances, emission reduction certificates and attestations can be recorded in the Swiss Emissions Trading Registry (for Switzerland and for companies that participate in emissions trading).

The Swiss ETS was linked to the EU ETS through a bilateral agreement which entered into force on 1 January 2020. Anyone participating in the Swiss or EU ETS can use emission allowances from both their own system and that of the other system to cover the relevant GHG emissions.

G.3 Carbon pricing

Under the CO_2 Act, a fee of CHF120 per tonne of CO_2 is charged on the import of carbon-based fuels.

G.4 Capacity markets

Switzerland does not have a capacity market. There are no legislative plans to introduce one.

H. Energy transition

H.1 Overview

The energy transition is part of the Energy Strategy 2050. The aim of this strategy is a 3% reduction in per capita energy consumption by 2020 and a 13% reduction by 2035, in each case compared to the level in the year 2000. Measures will include the decommissioning of Switzerland's five nuclear power plants by the end of their operating life, the upgrading of the electricity grids, a rise in the CO_2 fee, and the extension of the energy-efficient buildings' programme.

H.2 Renewable fuels

There are no national strategies or legislative frameworks to promote the usage of hydrogen and ammonia, other than supporting the research regarding these fuels.

H.3 Carbon capture and storage

There is no legislative framework regarding carbon capture and storage ("CCS"). However, Switzerland is supporting research into CCS and some pilot projects are in place.

H.4 Oil and gas platform electrification

Switzerland does not have any oil or gas platforms.

H.5 Industrial hubs

There are no current or planned industrial hubs or territorial clusters for renewable energy in Switzerland. There is no legislative framework to promote such industrial hubs or territorial clusters.

H.6 Smart cities

There is no legislative framework for smart cities in Switzerland.

I. Environmental, social and governance (ESG)

As of 1 January 2022, new reporting obligations on non-financial matters for large companies have been introduced. The report on non-financial matters will cover environmental matters, in particular the CO_2 goals, social issues, employee-related issues, respect for human rights, and combating corruption. The report will contain the information required to understand business performance, business results, the state of the undertaking, and the effects of its activity on these non-financial matters. It is expected that these reporting obligations will lead to energy saving investment and investments in renewable energies.

Energy law in Turkey

Recent developments in the Turkish energy market

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Turkey's energy and natural resources strategy is enshrined in Turkey's National Energy Plan ("TNEP") for 2023-2035, published by the Ministry of Energy and Natural Resources ("MENR"). According to the scenario in the TNEP for the period between 2023-2035:

- the primary energy consumption will increase to 205.3Mtoe in Turkey;
- the electricity consumption will reach 510.4TWh;
- the installed electricity capacity will increase to 189.7GW (52.9GW of solar, 29.6GW of wind and 7.2 of nuclear);
- the capacity expected to be commissioned will be 96.9GW;
- the share of intermittent renewable energy resources in the electricity generation will increase to 34.2% and the share of renewable energy resources will increase to 54.7%; and
- the share of intermittent energy resources in the installed electricity generation capacity will increase to 43.5% and the share of renewable energy resources will increase to 64.7%.

According to TNEP, the MENR plans to increase installed capacity of renewable energy sources to:

- 29.6GW for wind (24.6GW of onshore and 5GW of offshore);
- 52.9GW for solar;
- 35.1GW for hydro; and
- 5.1GW for geothermal and biomass by 2035.

The TNEP reiterates Turkey's intention to reach net zero emissions by 2053, in line with the EU policies to become climate-neutral by 2050.

Significant legislative developments

Changes to unlicensed electricity regulation

In May 2019, principles applicable to the unlicensed electricity market were amended to facilitate establishment of unlicensed energy facilities for individual consumption. The amendments were introduced by (i) the Presidential Decree dated 10 May 2019, which amended the Council of Ministers Decree on the Fees and Periods Applicable to Generation Facilities based on Renewable Resources and Local Content Addition dated 18 November 2013, and (ii) the new Regulation on Unlicensed Electricity Generation in the Electricity Market dated 12 May 2019 ("New Unlicensed Electricity Regulation"), which abolished the previous Regulation on Unlicensed Electricity Generation in the Electricity Market dated 2 October 2013 ("Abolished Unlicensed Electricity Regulation"). The changes are mainly aimed to facilitate self-consumption, by promoting electricity generation from small sized power plants without a licence requirement.

Accordingly, the upper limit for renewable energy-based generation facilities' installed capacity which are exempt from obtaining a licence and/or incorporating a company, has been increased from 1MW to 5MW. The New Unlicensed Electricity Regulation also introduced significant changes regarding connection principles. Under the New Unlicensed Electricity Regulation, solar or wind power-based unlicensed generation facilities' installed capacity can be up to the power capacity specified in the connection agreement of the consumption facility associated with the relevant unlicensed generation facility.

In addition to the new Unlicensed Electricity Regulation, the recent amendments to the Electricity Market Law abolished the approval requirement regarding direct and indirect shareholding and control changes of electricity generation licence holders.

On 22 December 2022, the Electricity Market Law introduced a new market activity, ie aggregation. The legal entities that have an aggregation license or supply license can combine multiple customer loads or generated electricity for sale or purchase. This activity will enable these customers to negotiate competitive electricity prices.

New principles for the renewable energy resource support mechanism

The Turkish Renewable Energy Resources Support Mechanism ("RERSM"), which the general public opinion considers to be a successful scheme to promote investments for renewable energy sources, is regulated by the Renewable Energy Resources Law ("RER Law"). On 2 December 2020, the law amending the Electricity Market Law and certain other laws was published in the Official Gazette ("Amendment Law"). The Amendment Law amended the RER Law (amongst others) and envisaged important changes regarding the RERSM.

Under the revised RERSM, renewable energy-based generation facilities commissioned before 30 June 2021 are permitted a feed-in tariff based on US$ with a purchase guarantee period of ten years following the commissioning date, as well as additional incentives for use of domestically manufactured equipment, based on US$ for five years. RERSM is applicable to generation facilities to be commissioned after 30 June 2021, however, are governed by the Presidential Decree dated 29 January 2021 ("Presidential Decree"). Under the Presidential Decree, generation facilities starting their operations after 30 June 2021 are entitled to (i) a feed-in tariff based on TRY for ten years, which is adjusted on a quarterly basis based on the inflation and FX rates which are subject to pre-determined monetary caps in terms of US$ and (ii) incentives for use of domestically manufactured equipment, based on TRY for five years.

Compared to the US$ based feed-in tariffs applicable to generation facilities commissioned before 30 June 2021, the TRY based feed-in tariffs under the new RERSM have resulted in a decrease of value due to the devaluation of TRY over US$. It is expected that with such a decrease of feed-in tariffs to be applied to renewable energy generators, Turkish banks' approach towards providing loans for renewable energy investments (eg green bonds) may be affected negatively.

Introduction of the electricity storage facilities regulation

In January 2021, Energy Market Regulatory Authority ("EMRA") published a draft regulation regarding electricity storage activities and requested opinions of the electricity market stakeholders regarding the draft regulation. Subsequently, the Electricity Market Storage Activities Regulation ("Storage Regulation") was published in the Official Gazette dated 9 May 2021.

Among several developments introduced by the Storage Regulation, the most significant is the possible integration of storage facilities with generation and consumption facilities. The Storage Regulation allows companies to build storage facilities within their power plants or consumption facilities, without a separate licence requirement. The Storage Regulation also allows supply licence holders to establish autonomous storage facilities (ie storage facilities without any integration to a generation or consumption facility), provided that their installed capacity is higher than 2MW.

These incentives are expected to entice market players to build more storage facilities to escalate the efficient use of their generated electricity and pave the way for the integration of storage facilities into the power grid.

Amendments to Energy Performance of Buildings Regulation

On 19 February 2022, the Energy Performance of Buildings Regulation was amended. Under this recently introduced amendment, for the period between 1 January 2023 and 1 January 2025, buildings having a construction area of 5,000 m^2 must be built as nearly zero-emission buildings and at least 5% of their primary energy use must be from renewable sources. After 1 January 2025, these requirements will apply to buildings having a construction area of 2,000 m^2 and the 5% threshold will be increased to 10%. This was a welcomed step for energy efficiency in Turkey.

Recent deals

Recent privatisations and privatisation news

Since 2013, Turkey has been privatising its electricity generation assets owned by Elektrik Üretim Anonim Şirketi ("EÜAŞ") and has also privatised all of its state-owned electricity distribution companies.

The number of privatised power generation assets has significantly decreased since 2019 when compared to the period between 2013 and 2019. In 2020, only one privatization took place regarding two small hydro-power plants with a total capacity of 4MW.[1] However, the number of privatisations increased in 2021 with seven completed tenders (six hydro power plants and one gas-fired power plant)[2], but it significantly decreased in 2022 with only one privatisation.[3]

In addition, under the Presidential Decision dated 2 July 2021, TEİAŞ is included in the privatisation programme. TEİAŞ's privatisation was aimed to be completed by the end of 2022 through a public offering, however the privatisation process is not yet completed.

Private deals

In 2022, the total value of 31 energy deals was estimated to be US$ 2 billion,[4] marking a 29% drop from US$ 2.8 billion generated by 40 deals in 2021.[5] This indicates an increase from the total value of energy deals in 2020, which was US$ 1.1 billion with a total of 22 transactions.[6] Even though the deal market slightly repaired in 2021, Turkey's energy sector has not been attracting as many investors as in recent years.

The most significant energy deals during recent years were carried out by OYAK, Turkey's largest occupational pension fund. In 2020, OYAK acquired Guzel Enerji (TOTAL Oil Türkiye) and M Oil from Demirören Holding and acquired an estimated share of 6% in the fuel retail market. Subsequently, OYAK acquired Milangaz, also from Demirören Holding, which is the fifth largest liquefied petroleum gas (LPG) distributor in Turkey, with an estimated market share of 8.6% in 2019.[7]

Notably, in 2021 and 2022, most of the energy deals involved the acquisition of renewable energy companies. With Turkey's recent ratification of the Paris Agreement, more investors may be interested in renewable energy deals in Turkey in the upcoming years.

Other significant market developments

Trans-Anatolian Natural Gas Pipeline ("TANAP") and TurkStream Natural Gas Pipeline ("TurkStream")

2020 and 2021 witnessed two important developments in the transit of natural gas through Turkey. Natural gas flow from Azerbaijan to Europe through TANAP and the Trans-Adriatic Pipeline ("TAP") commenced at the end of 2020. TANAP has an initial capacity of 16 billion cubic metres ("bcm") per year. Only 6bcm of this capacity has been allocated to the delivery of natural gas to Turkey and the remaining 10bcm is to be used for delivery of gas to Europe. TANAP's capacity is capable of being increased to 31bcm per year.

In addition to TANAP, gas flow through the TurkStream commenced in early 2020. TurkStream transports natural gas from Russia, across an offshore section under the Black Sea to Turkey and from Turkey to Europe through Bulgaria. The capacity of the TurkStream's two lines is 31.5bcm per year. These developments are of particular importance for Turkey's goal to become a regional energy hub as well as for Turkey's security of natural gas supply. Coupled with investments in natural gas storage facilities (the expansion of one of Turkey's two underground natural gas storage facilities' capacity to 5.4bcm per year and the commissioning of floating storage and re-gasification units) and investments in the transmission network, Turkey continues to strengthen its natural gas infrastructure.

With the abandonment of Nord Stream 2 pipeline in 2022 due to Russia's invasion of Ukraine, TANAP became more important, not only for Turkey's local supply, but also for the supply security of EU countries.

Natural gas discoveries in the Black Sea

One of the actions to be taken under the MENR's Strategic Plan for 2019-2023 was to conduct exploratory drilling activities in the Mediterranean Sea and in the Black Sea. The exploratory drilling activities in the Mediterranean Sea have raised tensions between Turkey and the members of the EU. In 2020, however, the Turkish President announced that its drill ship discovered 405bcm of natural gas in the Black Sea, marking Turkey's largest gas find. The natural gas discoveries in the Black Sea continued in 2021 and 2022. In December 2022, the Turkish President announced that the total natural gas amount discovered in the Black Sea is 710bcm. In November 2022, the Minister of Energy and Natural Resources announced that the natural gas explored in the Black Sea is intended to be integrated into Turkey's natural gas transmission system in March 2023. However, the feasibility of this timing remains to be tested.

YEK-G, Turkey's green certificate

Until 2021, the only renewable energy certificate scheme available in Turkey was the International Renewable Energy Certificate ("I-REC") scheme. EMRA then introduced the Renewable Energy Guarantee of Origin ("YEK-G") scheme. The legal framework governing the YEK-G scheme entered into force on 1 June 2021 and the first day of trading was 21 June 2021. The system is similar to the I-REC scheme. In the YEK-G scheme, the Turkish energy market operator, EPİAŞ, issues the YEK-G certificates. Owners of electricity generation facilities can register their facilities with the YEK-G system (if not already registered with the I-REC system). The YEK-G certificates are traded in the YEK-G market. The participants of this market are the generators of renewable electricity and suppliers, and they redeem the YEK-G certificates. Accordingly, end-users can purchase the YEK-G certificates by approaching participants.

Towards a national hydrogen strategy

Turkey has been developing its national hydrogen strategy since 2021. Accordingly, the MENR had already assigned the duty to test mixing hydrogen with natural gas in the distribution grid to the Turkey Natural Gas Distributors Association (GAZBIR), the natural gas distribution companies' association. Blending natural gas with other cleaner fuels such as hydrogen and integrating it into the existing natural gas grid is also set out as one of the main goals under TNEP.

On 19 January 2023, the MENR published Turkey's Hydrogen Technology Strategy and Roadmap (TNEP). At the launch of TNEP, the Minister of Energy and Natural Resources announced that (i) the green hydrogen obtained by using renewable energy sources through the electrolysis of water will be crucial for Turkey's net zero emission target, (ii) previous tests on mixing hydrogen with natural gas yielded successful results and further tests are ongoing, (iii) between 2030 and 2053, the mix ratio of hydrogen to natural gas is aimed to increase to 12%, and (iv) an incentive mechanism will be introduced for the use of the local hydrogen mixture grid.

If the required investments are made and 'green' hydrogen is produced in Turkey, energy experts believe that this green hydrogen can be exported to Europe as blended gas or pure hydrogen through TAP and the Turkey-Greece or Turkey-Bulgaria Interconnectors.

Ratification of the Paris Agreement

Turkey had signed the Paris Agreement in 2016 but not ratified it until recently. However, on 7 October 2021, Turkey completed the procedure for the ratification of the Paris Agreement under Turkish law. Turkey is currently listed under Annex I. Annex I includes the industrialized countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States. Turkey had submitted a proposal to be removed from Annex I at the 26th Session of the Conference of the Parties held in Glasgow, United Kingdom, but later withdrew this proposal.

Turkey's First EV

In 2018, Turkey set the goal to manufacture its own EV: TOGG. Mass manufacturing started in October 2022 and sales are expected to commence in February 2023.

Endnotes

1. PwC Energy Deals 2020, available at www.pwc.com.tr/tr/sektorler/enerji/turkiye-enerji-sektorundeki-birlesme-ve-satin-almalar-2020.pdf.
2. PwC Energy Deals 2021, available at www.pwc.com.tr/tr/sektorler/enerji/enerji-sektorundeki-birlesme-ve-satin-almalar-2021-final.pdf.
3. PwC Energy Deals 2022, available www.pwc.com.tr/tr/sektorler/enerji/enerji-sektorundeki-birlesme-ve-satin-almalar-2022.pdf.
4. Ibid.
5. PwC Energy Deals 2021, available at www.pwc.com.tr/tr/sektorler/enerji/enerji-sektorundeki-birlesme-ve-satin-almalar-2021-final.pdf.
6. PwC Energy Deals 2020, available at www.pwc.com.tr/tr/sektorler/enerji/turkiye-enerji-sektorundeki-birlesme-ve-satin-almalar-2020.pdf.
7. PwC Energy Deals 2020, available at www.pwc.com.tr/tr/sektorler/enerji/turkiye-enerji-sektorundeki-birlesme-ve-satin-almalar-2020.pdf.

Overview of the legal and regulatory framework in Turkey

A. Electricity

A.1 Industry structure

Nature of the market

Turkey's liberalisation process began in 2001 and the electricity market is now partly liberalised. The liberalisation continues progressively, and electricity generation, distribution and supply activities are now carried out by both private and state-owned companies.

The Turkish state generation entity Elektrik Üretim AŞ ("EÜAŞ") continues to have an important role in the electricity generation market as the owner and operator of all the transmission facilities. However, the role of private entities has rapidly increased, both through privatisations as well as new facilities. As of November 2022, 68% of Turkey's total installed electricity capacity is owned by private entities, while EÜAŞ retains the remaining 32%, either directly or through contractual rights.[1]

The distribution network is divided into 21 regions, with a different distribution company in each, all of which have been privatised. The state distribution entity Türkiye Elektrik Dağıtım AŞ ("TEDAŞ") does not directly operate any distribution companies but owns their shares.

The State transmission entity Türkiye Elektrik İletim AŞ ("TEİAŞ") conducts all of Turkey's transmission activities. Under the Presidential Decision dated 2 July 2021, TEİAŞ is included in the privatisation programme. The process for TEİAŞ's privatisation is still pending.

Key market players

In addition to private companies, there are three state-owned companies active in the electricity market:

- EÜAŞ, the state generation entity;
- TEİAŞ, the state transmission entity; and
- TEDAŞ, the state distribution entity.

Regulatory authorities

The Ministry of Energy and Natural Resources ("MENR") is responsible for preparing and implementing energy policies, plans, and programmes in coordination with its affiliated institutions. Under the support of the MENR, the Energy Market Regulatory Authority ("EMRA") is the competent administrative and regulatory authority overseeing the electricity market. EMRA's powers and duties include:

- issuing licences;
- setting, amending, enforcing, and supervising regulations on performance standards;
- distribution of power and customer services;
- setting out pricing principles; and
- maintaining the development and performance of infrastructure for implementation of new power trading and sales methods.

Legal framework

The Electricity Market Law ("EML") and the Electricity Market Licence Regulation ("Licence Regulation") are the primary pieces of legislation governing the electricity market, which entered into force on 30 March 2013 and 2 November 2013, respectively.

Since their enactment in 2013, both the EML and the Licence Regulation have been amended a number of times. The most recent amendments to both the EML and the Licence Regulation were made in 2022.

Implementation of EU electricity directives

Turkey has taken considerable steps in fulfilling the unbundling requirements set out in the Third Electricity Directive. On 12 September 2012, EMRA adopted Resolution No. 4019, separating the operations of companies with a distribution licence for distribution systems and retail sales. This ensures that distribution and retail operations are conducted by separate legal entities. In addition, in September 2012, EMRA introduced the Procedures and Principles concerning the Legal Unbundling of Distribution Systems and Retail Sales, which required the distribution utilities to establish a separate company for retail sale activities and obtain a separate retail sales licence from EMRA.

Shareholders of distribution utilities can own the shares of the newly established retail sales utilities. However, as of 1 January 2016, distribution utilities cannot purchase administrative and support services from companies under the parent company's control.

In addition, Turkey has been making progress in aligning its electricity market with EU directives, particularly in the fields of supply security and energy efficiency. TEİAŞ was an observer at the ENTSO-E, which allowed market players to freely import and export electricity between the EU countries and Turkey. The EU Commission's 2022 Turkey report states that *"although the Turkish Electricity Transmission System Operator's (TEIAŞ) observer membership of the European Network of Transmission System Operators for Electricity (ENTSO-E) was not renewed, TEIAŞ continued to be present in technical discussions of relevant working groups."*[2]

A.2 Third party access regime

TEİAŞ conducts all transmission activities in Turkey and the 21 distribution companies conduct the distribution activities in their respective regions. The details for connecting to the transmission and distribution systems, as well as the usage of this system and interconnections, are regulated under the Regulation on the Electricity Market Connection to and Use of the System ("System Connection and Use Regulation") and the Electricity Market Grid Regulation. As per the System Connection and Use Regulation, third parties must first go through a pre-licensing stage where EMRA requests a positive opinion from TEİAŞ or the relevant distribution licence holder for connecting into and usage of the system.

Once the preliminary licence is issued, the licence holder and TEİAŞ and/or the distribution licence holder must conclude connection and system usage agreements. The System Connection and Use Regulation regulates the principles regarding connection to and use of the system. The Electricity Market Tariff Regulation ("Tariff Regulation") regulates the terms and conditions regarding the applicable tariffs for connection to and use of the system. The System Connection and Use Regulation has been amended ten times since it entered into force on 28 January 2014. One of the amendments to the System Connection and Use Regulation is that the connection and system usage agreements cannot be concluded prior to obtaining the generation licence.

A.3 Market design

Turkey has taken significant steps on privatisation and the electricity market is now partly liberalised; however, some milestones are still yet to be achieved to reach full liberalisation (see section A.1).

A.4 Tariff regulation

The Tariff Regulation exhaustively lists the tariffs to be set by EMRA (eg transmission tariff, distribution tariff, retail sale tariff, and last resort supply tariff). EMRA announces the applicable tariffs on a quarterly basis, which are calculated based on the relevant service costs and in line with several income parameters. The retail sales tariff applies to the sale of electricity to non-eligible consumers and the last resort supply tariff applies to the sale of electricity to eligible consumers who did not choose their electricity supplier.

With the exception of the tariffs exhaustively listed under the Tariff Regulation, the EML states that individuals and legal entities can freely determine the prices in the bilateral agreements in relation to sale and purchase of electricity and/or capacity.

A.5 Market entry

Licensing regime

The Licence Regulation regulates the following market activities:

- generation (coal, hydro, geothermal, wind, solar, hydraulic, biomass, biogas, wave, current and tidal energy sources);
- transmission;
- distribution;
- wholesale and retail;
- trade;
- import and export;
- energy exchange; and
- aggregation (which was introduced in 2022).

Companies must obtain a licence from EMRA to conduct any of these activities. Companies must obtain separate licences for each electricity market activity. In addition, the Licence Regulation does not stipulate a licensing requirement for storage activities, but states that storage activities may be specified under the companies' generation or supply licences.

Under the Licence Regulation, in order to conduct electricity generation activities, companies must obtain a generation licence from EMRA. Only limited liability partnerships and joint stock corporations established in Turkey can obtain electricity generation licences. There are no restrictions on foreign shareholding in electricity market companies in Turkey.

Obtaining a preliminary licence is a prerequisite for obtaining a generation licence for applicants. A preliminary licence is issued for a specific term, to those having submitted an application to EMRA to conduct electricity generation activities. The purpose of the preliminary licence is to enable the applicant to obtain the necessary permits, approvals, and licences, as well as to acquire ownership or usufruct rights to the land where the generation facility is to be located, during the application's evaluation. The Licence Regulation determines the detailed requirements of the regulatory approval process to obtain a preliminary licence and generation licence. EMRA determines the information and documents to be submitted when applying for a preliminary licence. The Licence Regulation sets out that the term of a preliminary licence will be determined by EMRA, depending on source type and installed capacity. This term cannot exceed 36 months unless a force majeure event occurs.

The recent amendments to the Licence Regulation separates preliminary licence applications for RERA from those made by other entities generating electricity. Under the Licence Regulation, the generation licences are granted for a term of ten to 49 years. However, there is no time limitation as to the term of generation licences granted for RERA.

The EML defines the market activities that may be conducted without a licence. For instance, RES based generation facilities with an installed capacity of up to 5MW are exempt from the requirement of obtaining a licence.

On 12 May 2019, EMRA introduced the Regulation on Unlicensed Electricity Generation ("Unlicensed Generation Regulation"), which abolished the previous regulation on unlicensed electricity generation that had come into force on 2 October 2013. EMRA reported that the ultimate purpose of introducing the Unlicensed Generation Regulation is to promote the construction of energy facilities for individual consumption. Under the Unlicensed Generation Regulation, the previous requirement to incorporate a legal entity before establishing a power plant is abolished, enabling individuals to operate in the market directly.

Licence transfers/change of control situations

Generally, licence transfers are not permitted under the Licence Regulation. However, with approval from EMRA, legal entities with an electricity generation licence are permitted to transfer rights and obligations related to their licences to another legal entity by way of merger or spin-off, and to another legal entity established under the same shareholding structure. Additionally, legal entities with an electricity generation licence may transfer the generation facility to another legal entity seeking to conduct electricity generation activities, by way of sale, transfer, or lease, subject to EMRA's approval. Correspondingly, the legal entity acquiring the generation facility must obtain a new generation licence from EMRA. In addition to these transactions, the Licence Regulation grants a step-in right to banks and financial institutions that provide loans to licence holders, allowing them to request licence transfers to third parties from EMRA. The proposed transferee will undertake all obligations of the former licence holder under the relevant licence.

The following are not considered licence transfers:

- transfers to another legal entity established under the same shareholding structure;
- transfers by legal entities holding an electricity generation licence transferring the generation facility to another legal entity seeking to conduct electricity generation activities, by way of sale, transfer, or lease; and
- transactions relating to project financing allow the transferee to obtain a generation licence that maintains the terms and conditions of the former licence.

The Licence Regulation also sets out certain share transfer restrictions. Under the EML and Licence Regulation, direct or indirect changes in shareholding structure and/or share transfers (aside from certain exceptions set out under the Licence Regulation) are not permitted within the preliminary licence period. EMRA will cancel a preliminary licence if such a transaction occurs.

However, Article 57 of the Licence Regulation, which was amended many times following its entry into force, sets out certain exceptions to the share transfer restrictions with respect to the preliminary licence period.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

Under the EML, the distribution companies are responsible for lighting of public spaces and making the necessary investments to such effect, as well as the installation and operation of the metering systems throughout the respective distribution region. Until 31 December 2025, expenses arising from the lighting of public spaces will be covered by the MENR and the respective municipality and province.

Smart metering

Within the scope of the "Turkey Smart Grid 2023 Vision and Strategy Roadmap Summary Report", published by the Association of Distribution System Operators (ELDER) and EMRA[3], Turkey aims to set up a nation-wide smart metering infrastructure, which is expected to cover at least 80% of the distributed electricity in the country by 2025. These smart meters measure the use of electricity on a three-phase basis, based on specific time intervals. To promote smart metering, EMRA obliged distribution companies to submit a cost-benefit analysis and conduct pilot schemes in pre-determined regions of Turkey between 2018 and 2020.

Electric vehicles

The Turkish tax legislation promotes electric vehicles ("EVs"). Motor vehicle tax ("MVT") is applicable to EVs in Turkey, however, the amount of MVT to be paid for an EV equates to a quarter of the MVT to be paid for a car with an internal combustion engine. From 2020 to date, EVs held an advantage in terms of a special consumption tax. However, an import tax at the rate of 20% was imposed on EVs in 2022.

In 2021, e-scooter usage in Turkey was regulated for the first time when the Ministry of Transportation and Infrastructure, the Ministry of Environment and Urbanisation ("MEU"), and the Ministry of Internal Affairs published the Electronic Scooter Regulation on 14 April 2021.

In 2018, Turkey set the goal to manufacture its own EV brand: TOGG. Mass manufacturing started in October 2022 and sales are expected to commence in February 2023.

A.7 Cross-border interconnectors

The EML and the Electricity Market Import and Export Regulation ("Export/Import Regulation") set out the principles and procedures for electricity import and/or export, and the principles pertaining to allocation and use of interconnection capacity for cross border trade in the electricity market. Under the Export/Import Regulation, electricity import, and/or export from or to countries that meet the international interconnection condition can be conducted by the following entities, subject to certain conditions and EMRA's approval:

- private companies holding supply licences;
- EÜAŞ (ie the state-owned electricity generation entity); and
- companies holding a generation licence, only up to the total installed capacity (only export activities).

On 18 September 2010, a trial run was carried out for the synchronous parallel connection of the Turkish National Electricity System (operated by TEİAŞ) to the Continental Europe Synchronous Area. In April 2015, TEİAŞ became an observer member after Turkey's successful synchronisation with the ENTSO-E Continental Europe Region. TEİAŞ signed a long-term agreement for a permanent connection to the continental European grid, following the trial period that began in September 2010. TEİAŞ was an observer member of the ENTSO-E. Although TEİAŞ's application to continue as an observer member was not approved, TEİAŞ continues to be present in technical discussions of the relevant working groups. In recent years, Turkey expended its capacity of electricity interconnections with Bulgaria and Greece.

In addition to EU Member States, Turkey currently has electricity transmission interconnections with Georgia, Azerbaijan, Armenia, Iran, Iraq, and Syria. According to EMRA data, Turkey's main electricity imports are from Georgia and Bulgaria.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

The Petroleum Markets were liberalised following the introduction of the Petroleum Market Law ("PML") in 2003 and the Liquefied Petroleum Gas Market Law ("LPG Market Law") in 2005.

Key market players

Türkiye Petrol Rafinerileri AŞ ("TÜPRAŞ") is the key importer of crude oil and petroleum products. According to the EMRA Petroleum Market Sector Report, in 2021 TÜPRAŞ and STAR Rafineri AŞ ("STAR"), a SOCAR company, imported 54.87% and 22.58% of the crude oil and petroleum products imported to Turkey, respectively. TÜPRAŞ and STAR are followed by the two petroleum market distribution licence holders Petrol Ofisi AŞ (5.18%) and Opet Petrolcülük AŞ (5.16%).[4]

Moreover, with reference to their shares in the domestic sale of petroleum products, Petrol Ofisi AŞ (23.09%), Opet Petrolcülük AŞ (17.89%), Shell & Turcas Petrol AŞ (16.77%), BP Petrolleri AŞ (7.58%), and Güzel Enerji Akaryakıt AŞ (Total's licensee in Turkey) (6.37%) are the key players in the petroleum market in Turkey.[5]

Regulatory authorities

Under the PML and LPG Market Law, EMRA is the competent regulatory authority for the Petroleum Markets. EMRA's duties regarding the Petroleum Markets include preparation of regulations and pricing principles, licensing of facilities and activities, inspection of these facilities and activities, and enforcement of compliance with these regulations.

Legal framework

The PML and the LPG Market Law govern downstream petroleum and LPG market activities ("Petroleum Markets").

Smuggled and illegal fuel had been creating a significant issue, and tackling this issue was one of the main reasons for the enactment of the PML and LPG Market Law, and the regulations set by EMRA. To this end, the PML and LPG Market Law both have a licence requirement per facility for all activities in the Petroleum Markets. The types of licence are refining, processing, lubricant production, storage, transmission, eligible consumer, bunker delivery, distribution, transportation, and dealership.

The PML also requires refineries and importers to use a specific chemical, called National Marker, for diesel and gasoline. Additionally, distribution companies must install automated technology to monitor pump sales and regularly notify these metrics to EMRA. These key regulatory requirements have been successful in effectively preventing smuggled and illegal fuel in Turkey.

Other significant issues in the Petroleum Markets relate to competition restrictions and the typical retail ownership model in Turkey. Under the PML, a dealership agreement between a distribution company and a dealer must be an exclusive agreement. Under the Turkish Competition Board's communiqués, the term of an exclusive dealership agreement cannot exceed five years. This results in a five-year renewal cycle of dealership agreements, which supports competition among the distribution companies in the dealers' favour.
In addition, the PML provides that sales made by a distributor through the stations operated by it under a dealership licence cannot exceed 15% of the distributor's own local market share, and the distributor's total local market share cannot exceed 45% of the total local market. The LPG Market Law does not restrict sales made by a distributor through the stations operated by the distributor; however, it provides that the distributor's total local market share cannot exceed 45% of the total local market. The market shares of the key distributors in the Petroleum Markets are well below 45%. According to the EMRA sector reports of 2021, the largest market shares were 23.09% for Petrol Ofisi AŞ and 17.89% for Opet Petrolcülük AŞ in the petroleum market and 25.35% for Aygaz AŞ, 11.48% for Petrol Ofisi AŞ and 10.40% for İpragaz AŞ in the LPG market.

The typical retail station structure in the Turkish market is the Dealer Owned Dealer Operated ("DODO") model. Under the DODO model, the dealer owns/has rights over the real estate under a lease agreement or a usufruct agreement. However, the dealer provides rights over the real estate to the distributor under a lease agreement or a usufruct agreement. This is for the purpose of leverage for the distributor against contractual breaches by the dealer. However, this leverage is limited in time. In parallel with the maximum term of the exclusive dealership agreements under Turkish competition law, the Turkish Competition Board's communiqués state that the term of these lease agreements or usufruct agreements cannot exceed five years, which results in a five-year renewal cycle for stations operated under the DODO model.

Gas

Nature of the market

Due to insufficient natural gas sources, Turkey depends on imports of gas. Natural gas is imported from the Russian Federation, Azerbaijan, and Iran through pipelines. In addition, liquefied natural gas is imported ("LNG") from Nigeria and Algeria under long-term agreements and spot LNG is imported from several countries under agreements of less than one year.

Key market players

With the enactment of the Natural Gas Market Law ("NGML") in 2001, the Petroleum Pipeline Corporation ("BOTAŞ") lost its monopoly rights on natural gas imports, distribution, and sales. However, BOTAŞ remains the key player in the market, as it owns and operates the gas transmission network and has always imported more than 80% of the natural gas imported to Turkey. According to the EMRA Natural Gas Sector Report, in 2021, BOTAŞ imported 93.42% of the natural gas imported to Turkey, which indicates, in contradiction with the NGML's purpose, an increase in BOTAŞ's share in the import in recent years. In addition, although the NGML stipulated that BOTAŞ was to be unbundled starting from 2009, BOTAŞ has not been divided into separate companies.

The enactment of the NGML has however contributed to the liberalisation of the natural gas market. For example, on 30 November 2005, BOTAŞ transferred its existing agreement for the import of 4 billion cubic metres ("bcm") per year from Russia to four other natural gas import companies in a tender process. These four natural gas import companies are Shell Enerji AŞ, Bosphorus Gaz Corporation AŞ, Enerco Enerji Sanayi ve Ticaret AŞ, and Avrasya Gaz AŞ. In addition, after the expiration of the natural gas purchase agreement with Gazprom Export LLC ("Gazprom") on 31 December 2011, BOTAŞ did not renew this agreement due to the restrictions imposed under the NGML. Following the expiration of the natural gas purchase agreement between BOTAŞ and Gazprom, EMRA was permitted to grant import licences for the same volume and from the same country. Consequently, four natural gas import companies won the contract to import 6bcm per year to Turkey through the Russia-Turkey Natural Gas Pipeline. These companies are Akfel Gaz Sanayi ve Ticaret AŞ, Bosphorus Gaz Corporation AŞ, Batı Hattı Doğalgaz Ticaret AŞ, and Kibar Enerji Dağıtım Sanayi AŞ.

In addition, in 2020, two companies, namely Bosphorus Gaz Corporation AŞ and Engie Enerji Ticaret ve Pazarlama AŞ imported gas from Russia through the newly introduced spot pipeline gas import regime. This regime allows spot import licence holders to import gas to Turkey, using available capacity at the pipelines, after consideration of the capacity required for long-term natural gas purchase contracts.

Having said the above, in recent years BOTAŞ chose to enter into new natural gas purchase agreements for the import of natural gas from Azerbaijan and Russia after the expiration of long-term agreements, instead of opening the market further to private companies. This resulted in an increase of BOTAŞ's share in the import of natural gas.

Regulatory authorities

EMRA is the regulatory authority responsible for the regulation and supervision of the downstream natural gas market. As the regulatory authority, EMRA has introduced several regulations, communiqués, and decrees in relation to natural gas market activities.

Legal framework

The NGML governs downstream natural gas activities. Under the NGML, natural gas market activities are the import, export, transmission, storage, wholesale, and distribution of natural gas, as well as the sale, distribution, and transmission of compressed natural gas ("CNG").

Competition related restrictions are another important aspect of the natural gas market. Under the NGML, no company can sell natural gas corresponding to more than 20% of the estimated national consumption determined by EMRA and import companies cannot import natural gas corresponding to more than 20% of estimated national consumption. An amendment to the NGML introduced another restriction under which distributor licence holders can have licences in only two Turkish cities.

B.2 Third party access regime to gas transportation networks

Transmission and storage demand in the Petroleum Markets

Under the PML, a distribution licence holder cannot discriminate between the stations it operates and those operated by dealers. Transmission and storage licence holders with spare capacity in their facilities must address the transmission and storage demands of third parties if these demands conform to, among others, the tariff of the licence holder, the capacity of the relevant facility, and the minimum amount in the tariff of the licence holder.

Third party access to gas distribution, transmission, and storage networks

Under the NGML, distribution or transmission licence holders must provide access to the system or allow the use of the system without any discrimination between third parties.

In parallel with the NGML, the Natural Gas Market Licence Regulation provides that distribution, transmission, and storage licence holders can decline the demands of third parties and eligible customers only if their capacity is not sufficient, they cannot perform their existing obligations otherwise or they may be ordered to pay significant financial compensation as a result of their existing contractual obligations. In addition, if the third party undertakes to cover the necessary expenses, this third party's request cannot be declined.

The BOTAŞ Transmission Network Operation Principles ("Network Operation Principles") and the Regulation on Natural Gas Market Transmission Network Operation also regulate third party access to the transmission network. Under these pieces of legislation, a connection contract must be concluded between BOTAŞ and the relevant licence holder. In addition, a standard transportation contract must be concluded for gas transportation. The Network Operation Principles is also an integral part of the standard transportation contract to be concluded between BOTAŞ and the relevant licence holder.

The Natural Gas Market Distribution and Customer Relations Regulation also govern third party access to distribution networks, under which distribution companies must connect all consumers within their region.

B.3 LNG terminals and storage facilities

There are two underground natural gas storage facilities, the Silivri Underground Natural Gas Storage Facility and Tuz Gölü Underground Natural Gas Storage Facility owned and operated by BOTAŞ. The first phase of the Tuz Gölü Underground Natural Gas Storage Facility was completed and came into service in February 2017. The capacity of the Tuz Gölü Underground Natural Gas Storage Facility is planned to be increased to 5.4bcm in the coming years. In March 2019, BOTAŞ signed a contract with two subcontractors for this project.

There are also two LNG terminals, the BOTAŞ Marmara Ereğlisi LNG Terminal in Tekirdağ and the Ege Gaz Aliağa LNG Terminal. EMRA also categorised floating liquefied natural gas ("FLNG") activities as storage activities and issued the first FLNG licence to Etki Liman İşletmeleri AŞ for a FLNG terminal in Aliağa, İzmir and the second FLNG licence to BOTAŞ for an FLNG terminal Dörtyol, Hatay.

B.4 Tariff regulation

Oil

The pricing system in the petroleum market is governed by the Regulation on the Petroleum Market Pricing System ("Pricing Regulation"). The Pricing Regulation sets out three pricing schemes, the tariff scheme, price list scheme, and price announcement scheme. The tariff scheme applies to transmission, storage, refining, and distribution activities, the price list scheme applies to processing activities, and the price announcement scheme applies to dealership activities. Under the Pricing Regulation, the transmission licence holders, and the storage licence holders (if the storage facility is connected with the transmission system) must carry out their activities in accordance with their tariffs to be approved by EMRA (ie tariffs are prepared by the transmission licence holders and the storage licence holders, if the storage facility is connected with the transmission system, submitted to EMRA and approved by the same). The distribution licence holders and the storage licence holders (if the storage facility is not connected with the transmission system) must carry out their activities in accordance with their tariffs to be notified to EMRA.

In addition to the above, the PML sets out the formula for the calculation of the local crude oil's price. Additionally, under the PML, EMRA has the authority to set the minimum and maximum prices and to take necessary measures for implementation of these prices, either in a specific region in Turkey or in the entire Turkish territory for a term of up to two months in extraordinary circumstances (such circumstances include actions that are damaging to the competitive market environment, eg hidden price increase by the distribution companies).

Gas

The Natural Gas Market Tariff Regulation sets out the tariffs in the natural gas market (ie connection tariff, transmission tariff, storage tariff, wholesale tariff, and retail sale tariff). With respect to the wholesale tariff, the parties of the bilateral agreement can freely determine the price of the natural gas, but they must act in accordance with the principles to be set by EMRA (eg non-abuse of dominant position or security of natural gas supply). However, with the retail sale tariff, EMRA set the maximum amounts that the respective distribution company can apply to its subscribers.

B.5 Market entry

Gas

The NGML sets out restrictions and limitations with respect to the import of natural gas to Turkey through pipelines. BOTAŞ cannot enter into new natural gas purchase agreements until the share of gas imported by BOTAŞ falls to 20% of the annual national consumption amount. Secondly, Provisional Article 2 provides that EMRA must not permit any gas import company to import gas from countries from which BOTAŞ is already importing natural gas. However, EMRA may permit gas import companies to import natural gas from countries from which BOTAŞ is not already importing natural gas. Under the NGML, the criteria for evaluating whether to permit natural gas import from these countries are the establishment of a competitive natural gas market, and BOTAŞ's obligations arising from its existing agreements and export connections. However, it is worth noting that these restrictions and limitations are not applicable to the import of natural gas in the form of LNG.
In 2021, the Parliament introduced another exception to these restrictions and limitations, which allows spot import licence holders to import gas to Turkey using available capacity at the pipelines following consideration of the capacity required for long-term natural gas purchase contracts.

B.6 Cross-border interconnectors

Within the scope of the EU's INOGATE (Interstate Oil and Gas Transport to Europe) programme, a gas network interconnection was set up between Turkey and Greece that has been in operation since 18 November 2007. In late 2018, the Trans-Anatolian Natural Gas Pipeline ("TANAP") and Trans-Adriatic Pipeline ("TAP") completed their connection. Through the connection of these two pipelines, natural gas from the Shah Deniz Phase II field is being delivered to Europe. Finally, gas flow from Russia to Bulgaria through TurkStream commenced in 2020.

C. Energy trading

C.1 Electricity trading

In addition to the EML and the Licence Regulation, electricity trading is particularly regulated under the Regulation on Electricity Market Balancing and Settlement ("Balancing and Settlement Regulation"). This sets out the principles and procedures regarding day-ahead market, real time market, electricity futures market, and power balancing market, as well as settlement of trade in these markets. The electricity futures market, ie post-dated electricity market that imposes physical delivery obligations on market participants, was newly introduced to the electricity trading scheme in 2020 and started operations on 1 June 2021.

In Turkey, generation, supply, distribution, and transmission licence holder companies can conduct electricity trading activities in the day-ahead and real-time market, whereas only generation and supply licence holder companies can participate in the electricity futures market. To participate in the electricity market, electricity traders must either conclude a bilateral electricity purchase agreement with another licence holder or contribute to the organised markets themselves. Electricity is traded mostly through bilateral negotiated agreements on an over the counter (OTC) basis. Agreements are not subject to EMRA's approval and therefore all commercial terms and conditions are freely negotiable. Under the Balancing and Settlement Regulation, electricity trading can be conducted both physically and through financial instruments, depending on the relevant electricity market. The Balancing and Settlement Regulation envisages an imbalance regime where electricity can be traded in the balancing market.

The organised wholesale electricity markets (eg day-ahead and real-time markets) are operated by EPİAŞ, which also conducts the balancing activities in the market.

C.2 Gas trading

Natural gas distribution, import, wholesale, and CNG licence holders trade in natural gas. The volume of natural gas that the natural gas market licence holders sold to other natural gas market licence holders was approximately 39bcm in 2021, according to the EMRA Natural Gas Sector Report.

On 31 March 2017, the Regulation on the Organised Natural Gas Wholesale Market was published in the Official Gazette and entered into force on the same date. The organised natural gas wholesale market has been in operation since 1 September 2018. The market operator is EPİAŞ, and to be able to trade in the Organised Natural Gas Wholesale Market, entities are required to hold natural gas import, export, or wholesale licences.

D. Nuclear energy

Nuclear power is a key aspect of Turkey's aim for economic growth. Turkey had taken important steps for the construction of two nuclear power plants and for the required legal framework, however one of the projects was later abandoned.

Nuclear power plant projects

Turkey's first nuclear power plant project is the Akkuyu NPP, which entails the construction of four reactor units with a total capacity of 4,800MW. In 2010, Turkey and the Russian Federation signed an Intergovernmental Agreement ("IGA") and provided a build, own, and operate model for the Akkuyu NPP. EMRA issued the generation licence for the Akkuyu NPP on 15 June 2017, which is valid until 15 June 2066, and the Turkish Atomic Energy Authority ("TAEA"), which was the then competent regulatory authority, issued the construction licence for the first unit of the Akkuyu NPP on 2 April 2018. On 3 April 2018, the Russian and Turkish presidents launched the construction of the Akkuyu NPP. According to public statements, the pandemic did not stop the construction works for the Akkuyu NPP and the plant's first unit is expected to be commissioned in 2023.

The second nuclear power plant project was the Sinop NPP. The IGA related to the Sinop NPP was signed by Turkey and Japan in 2013, and Turkey ratified this IGA in 2015. However, the project was abandoned in 2018 following completion of a feasibility study. That said, in November 2022 an MENR official stated that Turkey is currently discussing with Rosatom the possibility for the construction of a second nuclear power plant in Sinop. He added that Turkey is in contact with the Chinese government for construction of a third nuclear power plant in Turkey.

Regulatory body and licensing

Under the Law on the Turkish Atomic Energy Authority, the TAEA had been assigned responsibilities for both the promotion of nuclear energy and regulatory control of nuclear activities, and it was the licensing authority for nuclear facilities (ie site licence, construction licence, and operation licence). However, under international standards, the regulatory body had to be independent of all entities that promote the development of the nuclear industry.

On 2 July 2018, the Council of Ministers adopted the Decree on the Organisation and Duties of the Nuclear Regulatory Authority ("NRA"), under which the NRA was established and was assigned as the regulatory control institution for nuclear activities. The NRA's Board is comprised of five members appointed by the President of the Republic of Turkey. When appointing the members, the President also selects the president and the second president of the NRA Board among these five members.

Finally, in 2020, the Turkish Energy, Nuclear and Mineral Research Agency ("TENMAK") was established. TENMAK was assigned the duty of, among others, increasing Turkey's competitive power in the field of nuclear energy.

Legal framework

Since its creation, the NRA adopted secondary legislation, governing different aspects of nuclear energy such as Regulation on Nuclear Safeguard, Regulation on Organisational Structure and Personnel in Nuclear Power Plants, and Regulation on Nuclear Export Control.

Third party liability

Turkey ratified the Convention on Third Party Liability in the Field of Nuclear Energy of 29 July 1960, as amended by the Protocol of 28 January 1964 and by the Protocol of 16 November 1982 ("Convention"). In December 2021, Turkey also ratified the 2004 Additional Protocol to the Convention, which sets out €700 million as the operator's minimum liability. It is worth noting that Turkey ratified the protocol with a limited reservation in relation to the €700 million minimum liability amount.

E. Upstream

Upstream activities and transit passage of petroleum

Upstream oil and gas activities are governed by the Turkish Petroleum Law ("TPL") and the transit passage of petroleum is regulated under the Law on Transit Passage of Petroleum through Pipelines ("Transit Law"). The General Directorate of Mining and Petroleum Affairs ("GDPA") and the Transit Pipelines Department of the MENR are the competent regulatory bodies for the oil and gas upstream and transit activities, respectively.

Key legislative features

The TPL entered into force on 30 May 2013 and replaced the former petroleum law dated 1954. The TPL divides Turkey into two petroleum districts ie onshore and offshore. It requires entities to obtain a survey permit, an exploration licence, or an exploitation licence, depending on the type of upstream petroleum activity they wish to pursue.

The term of the exploration licence has been set at five years for onshore and eight years for offshore activity. The terms of these licences may be extended up to nine years for onshore and 14 years for offshore exploration. An exploitation licence is granted for 20 years and may be extended twice, each time for ten years.

Petroleum right holders are permitted to export 35% for onshore and 45% for offshore, of the crude oil or natural gas produced in the fields discovered after 1 January 1980. The remaining volume and the total of the crude oil and natural gas produced in the fields discovered before 1 January 1980 must be reserved for the needs of the state. Additionally, under the TPL, a state share corresponding to 12.5% of the petroleum produced by exploration or exploitation must be paid to the State.

The TPL aims to liberalise oil and gas exploration and production and to attract foreign investors. To this end, the TPL provides certain exemptions from customs tax, fees, and stamp duty on import or domestic procurement of the materials, equipment, fuel, and land, sea and air transportation vehicles approved by the GDPA. Another tax exemption is that exploration and exploitation licence holders can use fuel exempted from special consumption tax. In addition, the total taxation of a petroleum right holder company, together with taxes withheld on behalf of its shareholders, cannot exceed 55%.

International oil and gas pipelines

The Transit Law assumes the existence of an IGA ie it is applicable only if there is an international agreement related to the pipeline. Under this law, the applicable legal framework for a transit pipeline consists of the Transit Law, the IGA, and the commercial agreements.

International oil pipelines

There is currently only one international transit pipeline crossing Turkey, ie the Baku-Tbilisi-Ceyhan Crude Oil Pipeline owned by the BTC Consortium, which transports crude oil from the Caspian region to Ceyhan.

International gas pipelines

The international natural gas import and export pipelines are:

- Russia-Turkey Western Route Natural Gas Pipeline crossing Ukraine, Romania and Bulgaria to Turkey;
- Russia-Turkey Blue Stream Natural Gas Pipeline, transporting natural gas from Russia to Turkey through the Black Sea;
- Iran-Turkey Natural Gas Pipeline, transporting natural gas from Iran to Turkey;
- Baku-Tbilisi-Erzurum Natural Gas Pipeline, transporting natural gas from Azerbaijan through Georgia to eastern Turkey;
- Turkey-Greece Natural Gas Pipeline, transporting natural gas from Turkey to Greece;
- TANAP transporting natural gas from Shah Deniz Phase II field in Azerbaijan to Turkey and Europe. Construction of this pipeline began in 2015 and the supply of gas from Azerbaijan to Turkey through TANAP began in June 2018. After completion and connection of the TANAP and TAP, gas deliveries to Greece began at the end of 2020. Along the TAP, natural gas from the Shah Deniz Phase II field will be delivered to South Italy through Greece and Albania; and
- The TurkStream Natural Gas Pipeline transports gas from Russia across an offshore section under the Black Sea to Turkey and from there onto European markets through Bulgaria. On 10 October 2016, Turkey and the Russian Federation signed an IGA for the construction of the TurkStream pipeline. Gas deliveries through the TurkStream started in early 2020.

In addition, the completion of the following natural gas pipeline projects will make Turkey a regional energy hub and secure its natural gas supply security:

- The Trans Caspian Natural Gas Pipeline, transporting Turkmen gas across the Caspian Sea to Azerbaijan and Turkey; and
- The Iraq-Turkey Natural Gas Pipeline, transporting natural gas from northern Iraq to Turkey.

F. Renewable energy

F.1 Renewable energy

Under Turkish law, renewable energy is governed by several legislative instruments such as the EML, the Licence Regulation, the Law on Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy ("RER Law"), the Regulation on Certification and Supporting of Renewable Energy Resources ("RERSM Regulation"), the Regulation on Renewable Energy Resource Areas ("RERA Regulation"), the Geothermal Resources and Natural Mineral Waters Law, and the Energy Efficiency Law ("EEL").

There are several regulations on renewable energy, dealing with issues ranging from water utilisation agreements to equipment standards for solar energy plants. Among the important pieces of secondary legislation are the following:

- Regulation on Solar Energy Based Electricity Generation Facilities;
- Regulation on Competition in relation to Preliminary Licence Applications for Establishment of Wind or Solar Energy Based Generation Facility;
- Regulation on Technical Assessment of Applications for Solar Energy Based Generation; and
- Regulation on Technical Assessment of Applications for Wind Energy Based Generation.

Renewable energy resources support mechanism

The RER Law's purposes include utilisation of renewable energy resources for generating electrical energy. To encourage this, in 2011, the law introduced a support mechanism, namely the Renewable Energy Resources Support Mechanism (RERSM). This support mechanism provides for a guaranteed feed-in tariff for a period of ten years as well as an additional tariff for a period of five years, if domestically manufactured equipment is used in the plant. The prices contained in the guaranteed feed-in tariff were in US$. However, for plants to be commissioned after 1 July 2021, the prices are in TRY and these prices are less than their US$ equivalent in the previous feed-in tariff. These prices will be adjusted on a quarterly basis, taking into account the inflation and foreign exchange rates, subject to a US$ cap. Despite this adjustment mechanism, the prices in TRY may have a negative effect in future renewable energy investments in Turkey.

RERA regulation

For a more efficient use of RERA, the MENR adopted the RERA Regulation. This regulation regulates the determination of RERA as well as the competitive process to obtain the usage rights in these areas. One of the purposes enshrined in this regulation is technology transfer through use of domestically manufactured equipment.

Renewable energy certificate schemes

Since 1 June 2021, there have been two renewable energy certificate schemes available in Turkey. The first scheme is the International Renewable Energy Certificate ("I-REC"). The International REC Foundation ("Foundation") is a non-profit organisation that provides an attribute tracking system based on the I-REC Code rules and regulations. In Turkey, the Foundation has authorised Foton Yazılım Teknolojileri ve Enerji Danışmanlık Hizmetleri AŞ ("Foton") to register and issue an I-REC. The owners of electricity generating facilities can register their facilities with the I-REC system. Foton issues I-RECs based on reported generation from these electricity generating facilities (one I-REC per MWh of electricity production). Accordingly, end-users can purchase and redeem I-RECs. They can do this through their accounts in the system or through market players (eg generators of renewable energy and suppliers). Using I-RECs, end-users can prove their renewable energy use.

The second scheme is the Renewable Energy Guarantee of Origin ("YEK-G") scheme, which EMRA introduced in 2021. The legal framework governing the YEK-G entered into force on 1 June 2021 and the first day of trading was 21 June 2021. The system is similar to the I-REC. Under this scheme, the Turkish energy market operator, EPİAŞ, issues the YEK-G certificates. Owners of electricity generation facilities can register their facilities with the YEK-G system (if not already registered with the I-REC system). The YEK-G certificates are traded in the YEK-G market. The participants of this market are the generators of renewable electricity and suppliers, and they redeem the YEK-G certificates. Accordingly, end-users will be able to purchase the YEK-G certificates by approaching the participants. International recognition of the YEK-G certificates is still to be tested.

F.2 Renewable pre-qualifications

To participate in competitions to be organised under the RERA Regulation, applicants are required to fulfil the conditions that are contained in the announcement for the competition; the RERA Regulation does not provide a list of these conditions. However, those who are entitled to apply for a pre-licence under this regulation must fulfil the conditions required to obtain a pre-licence under the Licence Regulation.

F.3 Biofuel

Turkish energy legislation provides for blending requirements. EMRA has issued two communiqués to set out the blending requirements for the refineries and distribution licence holders. Under these communiqués, the refineries and distribution licence holders are required to blend ethanol, produced from domestic agriculture products, with gasoline and the volume of the ethanol must be equal to or exceed 3% of the total volume. However, EMRA reduced this percentage to 2% for 2022 and 2023.

Moreover, the distribution licence holders are required to blend biodiesel, produced from domestic agriculture products and/or biowaste, with diesel and the volume of the biodiesel must be equal to or exceed 0.5% of the total volume.

G. Climate change and sustainability

G.1 Climate change initiatives

Turkey became a party to the United Nations Convention on Climate Change in 2004 and also ratified the Kyoto Protocol in 2009. The Kyoto Protocol was extended by the Doha Protocol in December 2012. However, although Turkey is listed in Annex 1 of the Kyoto Protocol, Turkey is not within the scope of Annex B and therefore has no quantitative carbon emission reduction obligation under the Kyoto Protocol. Turkey had also signed the Paris Agreement in 2016 but had not ratified it until recently. However, on 7 October 2021, Turkey completed the procedure for the ratification of the Paris Agreement under Turkish law. Turkey is currently listed under Annex I. Annex I includes the industrialized countries that were members of the OECD (Organisation for Economic Co-operation and Development) in 1992, plus countries with economies in transition (the EIT Parties), including the Russian Federation, the Baltic States, and several Central and Eastern European States. Turkey had submitted a proposal to be removed from Annex I at the 26th Session of the Conference of the Parties held in Glasgow, United Kingdom, but later withdrew this proposal.

To comply with the multinational initiatives regarding climate change, Turkey has taken a set of legislative measures to increase energy efficiency and renewable energy generation. In this regard, the Parliament has enacted and amended the EEL and the Environment Law. In addition, secondary legislation on specific matters such as GHG, carbon emissions and ozone-depleting substances has been adopted. The EEL provides for a support mechanism for energy efficiency implementation projects.

In November 2017, MENR has announced a National Energy Efficiency Action Plan ("NEEAP") for the 2017-2023 period, which envisage the following actions:

- identifying the potential of cogeneration, district heating, cooling systems and preparing a roadmap for legislation;
- implementing efficiency standards for the natural gas infrastructure;
- presenting customers with comparable and detailed bills;
- creating an energy data platform for smart management of measurement data;
- harmonising the legislative framework on electric metering with the EU codes (ie scale up smart metering);
- implementing minimum performance standards for transformers;
- managing peak demand arising from heating and cooling;
- improving energy efficiency in public lighting, electricity transmission and distribution and existing power generation plants; and
- building a market infrastructure for demand-side response.

To carry out energy efficiency studies and implement, monitor, and update the NEEAP, Turkey established the NEEAP Monitoring and Steering Board by issuing a Presidential Circular on 7 December 2019.

On 17 February 2021, the Minister of the Ministry of Environment and Urbanisation ("MEU") announced the "Fight Against Climate Change Declaration", which involves a set of measures to minimise the impact of climate change in Turkey. The Minister stated that a report on the fight against climate action will be presented in 2021 to Parliament to help it draft climate legislation.

On 19 February 2022, the Regulation on Energy Performance of Buildings was amended. Under this amendment, for the period between 1 January 2023 and 1 January 2025, buildings having a construction area of 5,000 m^2 must be built as nearly zero-emission buildings and at least 5% of their primary energy use must be from renewable sources. After 1 January 2025, these requirements will apply to buildings having a construction area of 2,000 m^2 and the 5% threshold will be increased to 10%.

G.2 Emission trading

Turkey is not a party to the EU ETS, and therefore has not implemented the EU ETS Directive or the New EU ETS Directive.

In recent years, Turkey took significant steps towards the establishment of a nationwide ETS but to date does not have an operating scheme. The MEU has published the Roadmap regarding the formation of a Greenhouse Gas Emission System in Turkey ("GHG Roadmap") to lay out the applicability and the implementation of potential ETS in Turkey.[6] On 27 October 2020, the MEU Deputy Minister announced that the MEU is working on a draft regulation regarding ETS.

G.3 Carbon pricing

As Turkey is not a party to the EU ETS and has not implemented any regulations on a national ETS, it does not have any established carbon pricing strategy. Even though the GHG Roadmap states that Turkey is considering the carbon pricing model, it does not include any forecasts on the details of this pricing model.

G.4 Capacity markets

The EML and the Communiqué on Electricity Market Capacity Mechanism ("Capacity Communiqué") govern the established capacity mechanism in Turkey. The capacity mechanism is operated by TEİAŞ. Under the Capacity Communiqué, TEİAŞ makes pre-determined payments to generation licence holders on an annual basis for the establishment and/or maintenance of a sufficient established capacity. The licence holders apply to TEİAŞ to participate in the capacity mechanism.

H. Energy transition

H.1 Overview

Turkey has set its energy transition policy on three main pillars: security of supply, localisation, and predictability in the markets. With the increase of RES and domestic supply, Turkey aims to reduce the foreign dependency rate and the primary energy consumption by 14% until 2023. In recent years, the Turkish government focused on policymaking with a particular interest to increase investments in the renewable energy sector (see section F). Turkey's total installed capacity for electricity generated from renewable sources has been gradually increasing since 2010. Turkey currently generates almost half of its electricity through renewable sources.

H.2 Renewable Fuels

Hydrogen

Although Turkey does not currently have a legislative framework regarding the licensing, production, transmission, and distribution of hydrogen, the possible use of hydrogen has been referred to in several secondary legislation, as well as the NEEAP for 2017-2023.

On 24 January 2020, MENR published a 'white paper' to seek recommendation and further insight from hydrogen stakeholders to set up a roadmap regarding Turkey's hydrogen strategy. The 'white paper' is followed by a 'red paper', which includes MENR's developed strategies for the establishment of a hydrogen market. MENR is expected to draft a 'green paper' to lay out the applicability and the implementation of Turkey's hydrogen strategy, as well as the need to establish a regulatory framework for hydrogen. In April 2021, the Minister of MENR announced that Turkey's national hydrogen strategy report would be finalised in 2021.

In 2021, Turkey was laboratory testing hydrogen combined with natural gas in an effort to assess the potential distribution of a hydrogen-natural gas mixture through the national distribution network. According to Turkey's National Energy Plan,[7] Turkey intends to distribute a hydrogen-natural gas mixture with a 3.5% hydrogen through its national distribution network by 2035.

On 19 January 2023, the MENR published Turkey's Hydrogen Technology Strategy and Roadmap. At the launch of this strategy document, the Minister of Energy and Natural Resources announced that (i) the green hydrogen obtained by using renewable energy sources through the electrolysis of water will be crucial for Turkey's net zero emission target, (ii) previous tests on mixing hydrogen with natural gas yielded successful results and further tests are ongoing, (iii) between 2030 and 2053, the mix ratio of hydrogen to natural gas is aimed to increase to 12%, and (iv) an incentive mechanism will be introduced for the use of local hydrogen mixture grid.

Ammonia

Turkey does not have a legislative framework regarding the use of ammonia as an energy source.

H.3 Carbon capture and storage

Turkey has no legislative framework for carbon capture and storage ("CCS") and has not implemented the CCS Directive. Although an increasing number of research centres and academics have been carrying out internal CSS studies for some time, Turkey does not have a national CSS project in place.

H.4 Oil and gas platform electrification

Turkey has no legislative framework for oil and gas platform electrification or any current/planned platform electrification project.

H.5 Industrial hubs

Turkey's energy investments are widely dispersed throughout the country, eg renewable energy investments usually take place in the Aegean Region whereas oil and gas related facilities are mainly located at the South Eastern part of the country. Turkey's ultimate purpose is becoming an industrial energy hub as a country, due to its geopolitical position (between Asia and Europe) in terms of energy transmission. Through natural gas pipelines such as TANAP and TurkStream as well as the natural gas discovery in the Black Sea region in August 2020, Turkey plans to become a regional energy hub and secure its natural gas supply. In addition, Turkey also aims to become a solar and wind energy hub by 2023.

H.6 Smart cities

Turkey introduced the 2020-2023 National Smart Cities Strategy and Action Plan ("NSCSAP") by issuing a Presidential Circular on 23 December 2019. The NSCSAP specifies the objectives:

- creating an effective smart city ecosystem;
- increasing the smart city transformation capacity;

- creating a facilitating and guiding environment regarding smart city transformation; and
- ensuring smart city transformation in urban services.

The NSCSAP introduces a total of 40 actions to be implemented, the most significant of which are:

- preparing a local smart transition strategy for every city;
- forming a smart city index as an evaluation model;
- establishing sustainability tracking mechanisms such as the Smart City Technology Radar;
- increasing the human resource capacity and quality;
- improving the quality of smart city components; and
- providing the necessary governmental incentives to attract attention to smart transition.

NSCSAP also introduces a plan regarding the cities' smart energy transformation, which is increasing the maturity of smart energy by optimising energy resources, grid management and energy consumption, ensuring efficient use of energy and utilisation of renewable energy and alternative energy sources.

I. Environmental, social and governance (ESG)

Turkey does not have a standard environmental, social, and governance ("ESG") legal framework. Instead, ESG legal framework in Turkey is not fully consolidated, ie specific ESG related matters are addressed under, among other things, different pieces of legislation and regulatory resolutions.

In October 2020, the Capital Markets Board ("CMB") amended the Corporate Governance Communiqué, which sets out the corporate governance principles for listed companies. These principles require publicly listed companies to comply with the regulations in relation to environment, social, and corporate governance principles. The changes made to the Corporate Governance Communiqué state that publicly listed companies are required to report on their compliance with the Sustainability Principles Compliance Framework ("Framework"). The environmental principles under the Framework call on companies to disclose their policy, practice, action plan, environmental management systems, and their programme in the area of environmental management. The environmental principles encourage companies to set their targets to reduce their environmental impacts. Accordingly, Turkish energy conglomerates have begun to place more importance on ESG disclosures, particularly on environmental principles.

Endnotes

1. See www.teias.gov.tr/tr-TR/kurulu-guc-raporlari.
2. See www.neighbourhood-enlargement.ec.europa.eu/system/files/2022-10/T%C3%BCrkiye%20Report%202022.pdf.
3. Seewww.elder.org.tr/Content/yayinlar/TAS%20EN.pdf.
4. See www.epdk.gov.tr/Detay/Icerik/3-0-107/yillik-sektor-raporu.
5. Ibid.
6. See www.pmrturkiye.csb.gov.tr/wp-content/uploads/2020/12/Turkiyede-Sera-Gazi-Emisyon-Ticareti-Sisteminin-Kurulmasina-Yonelik-Yol-Haritasi.pdf.
7. See www.enerji.gov.tr//Media/Dizin/EIGM/tr/Raporlar/TUEP/T%C3%BCrkiye_Ulusal_Enerji_Plan%C4%B1.pdf.

Energy law in Ukraine

Recent developments in the energy sector in Ukraine

Glib Bondar, senior partner, and Anna Mykhalova*, associate, Avellum

In 2021-2022, Ukraine completed the following tasks:

- introduced the PSO financial model;
- approved the Second Nationally Determined Contribution to the Paris Agreement, according to which, Ukraine promises to reduce the greenhouse gas ("GHG") emissions by 65% by 2030 from 1990 levels. Ukraine's previous commitment was to reduce the GHG emissions by 40%;
- adopted the Law "On Energy Efficiency";
- joined the NATO Energy Security Centre of Excellence; and
- certified the electricity TSO for synchronisation with European networks (ENTSO-E) and fully synchronised with ENTSO-E.

The synchronisation with ENTSO-E had been scheduled for 2023, however, on 16 February 2022, the Ukrainian power system was urgently synchronised with ENTSO-E following Russian military aggression against Ukraine.

The Ministry of Energy is also working on the development of the Energy Strategy of Ukraine until 2050 and the Hydrogen Strategy of Ukraine.

Energy efficiency

On 13 November 2021, the new Law "On Energy Efficiency" ("Law") came into force to replace the outdated 1994 law. Over 40 pieces of secondary legislation are still to be drafted by the Government to make the Law operational.

The Law brings Ukrainian energy efficiency standards in line with the EU Directives 2009/125/EC, 2012/27/EC and Regulation (EU) 2017/1369. It outlines the principles of state policy in the field of energy efficiency, such as smart metering and a smart grids system, energy management and audits. The law also introduces energy efficiency criteria for public procurement procedures by state organs and local administrations; they will be required to purchase equipment with the highest of energy efficiency characteristics.

Importantly, the Law removed certain technical obstacles for entering into contracts with energy service companies (ESCO contracts), which paves the way for private investments into energy efficiency measures. It is estimated that ESCO contracts could result in an energy saving of up to 35%. For the first time, the Law introduces liability for businesses that fail to achieve the indicator of annual reduction in energy consumption (a fine of UAH510,000 and UAH1.02 million (approximately US$18,000 and US$36,000) for non-compliance below 50% and above 50% respectively). The National Energy and Utilities Regulatory Commission (NEURC) will administer the fines. The indicator may not be less than 0.8% of the average aggregate amount of energy transmitted calculated based on 2017-2019 figures. The businesses continue to assess the possible outcomes of this norm, which is a large element of economic, social and governance (ESG) commitments.

National action plan of energy efficiency

The Law envisages the creation of the National Action Plan of Energy Efficiency ("Plan"). On 29 December, the Government of Ukraine approved the Plan until 2030 and the programme of actions for 2021-2023 to implement the Plan. The Plan is expected to be revised every three years. The Plan is a milestone document specifying the means to achieve energy efficiency, timeframes, sources and amount of funds. Under the Law, Ukraine committed to invest 1% of its annual budget for energy efficient needs, although this figure is doubted by the professional community. The declared goal of the Plan is to reduce primary and ultimate energy consumption to 91.5 million and 50.5 million tonnes of oil equivalent by 2030 (a reduction of 22.3% and 17.1% respectively). The territorial communities will need to develop their own municipal energy efficiency plans within three years. The existence of such plans would be a precondition to receiving support from the state budget.

Thermal modernisation programme

At the end of 2021, the President of Ukraine announced the start of the "Great Thermal Modernisation" programme to enhance energy efficiency of public and residential buildings. On 23 December 2021, the Cabinet of Ministers of Ukraine approved a draft law and is expected to introduce it to the Parliament to create the legislative framework for the programme. Although few details are available now, the programme is claimed to become a driver for Ukraine's economy and energy sector. The declared goal for 2022 is to enhance energy efficiency in 5,000 multi-apartment buildings. Experts claim such a big plan cannot rely only on state funds, which is why the removal of technical obstacles for ESCO contracts is timely.

Ukraine is on the right track to keep in step with world energy efficiency trends, but it is the quality of the proposed executive decisions that will determine its success.

*Anna Mykhalova left the firm in March 2023

Overview of the legal and regulatory framework in Ukraine

A. Electricity

A.1 Industry structure

Nature of the market

On 11 June 2017, the Law of Ukraine on the Electricity Market became effective ("Electricity Market Law"). The Electricity Market Law introduced a legal framework for the operation of a new liberalised electricity market in compliance with the TEP.

The new liberalised electricity market was launched on 1 July 2019 and consists of several submarkets (see section A.3).

Key market players

The key market players are: (i) producers, (ii) traders, (iii) suppliers, (iv) market operator, (v) DSOs, (vi) TSO and (vii) State Enterprise "Guaranteed Buyer" ("Guaranteed Buyer").

Producers

Producers are entities licensed to generate electricity. Electricity producers include thermopower plants ("TPPs"), nuclear power plants ("NPPs"), hydro power plants ("HPPs") and renewable power plants ("RPPs"). The largest electricity producers are the state enterprise National Nuclear Energy Generating Company Energoatom ("Energoatom"), state-owned Public Joint-Stock Company Ukrhydroenergo ("Ukrhydroenergo") and the largest privately owned group of energy companies in Ukraine, ie DTEK.

Traders

Traders are licensed legal entities that buy electricity solely for the purpose of reselling it, except for sales under a contract for the supply of electricity to a consumer. Traders may sell and purchase electricity on the submarkets, including the bilateral contracts market, but are prohibited from supplying electricity to end consumers.

Suppliers

Suppliers are entities licensed to supply electricity to end consumers at free non-regulated prices.

The Market Operator is a legal entity responsible for organisation of the purchase and sale of electricity on day-ahead and intraday markets. The Market Operator cannot perform electricity generation, electricity transmission, electricity distribution, electricity supply to customers and trade activities.

DSOs

The distribution system operators ("DSOs") are entities licensed to distribute electricity through regional electrical grids. The Electricity Market Law requires the DSOs to be unbundled from electricity generation, supply and transmission including in terms of ownership.

TSO

The transmission system operator ("TSO") is a state-owned company that obtained the licence for electricity transmission. The functions of the TSO are currently performed by the Private Joint Stock Company "National Power Company '"Ukrenergo'" ("Ukrenergo"). On 3 December 2021, the Energy Community published a positive opinion on the certification of Ukrenergo - the Ukrainian electricity TSO, as an independent system operator ("ISO") in accordance with requirement of the Electricity Market Law and the TEP.

Guaranteed Buyer

The Guaranteed Buyer is a state enterprise that is obliged to purchase electricity from the renewable energy source ("RES") producers to which the '"green tariff'" was granted or for which the purchase price was established through auction regime.

Regulatory authorities

The National Energy and Utilities Regulatory Commission ("NEURC" or "Regulator") is a central executive body with a special status of a state regulator in the electricity sector. The NEURC performs its functions based on Law of Ukraine "On the National Commission for State Regulation in the Energy and Utilities Sectors" No. 1540-VIII dated 22 September 2016.

Under the Electricity Market Law, the NEURC has powers for the state regulation by means of, among other things, the following: (i) issuing licences for electricity generation, electricity transmission, electricity distribution, electricity supply to customers, trade activities, (ii) issuing licences to the Market Operator and the Guaranteed Buyer for the performing of their functions, (iii) approval of certain licensing rules, (iv) taking decisions on the certification of the TSO, (v) approval market rules, day-ahead and intraday market rules, transmission system code, commercial metering code, retail market rules etc, (vi) forming the tariff policy, and (vii) exercising monitoring.

The Ministry of Energy is a central executive body responsible for the state management body in the electricity sector. Under the Electricity Market Law, the powers of the Ministry of Energy, include the following: (i) formation and implementation of the state policy in the electricity sector, taking into account the Energy Strategy of Ukraine, and formation of the oversight state policy in the electricity sector, (ii) preparation of the state target programmes, (iii) preparation and approval of safety rules for, and monitoring of, the electricity supply, and (iv) preparation and approval of technical regulations.

Certain aspects of the electricity sector are regulated by the Ministry of Ecology and Natural Resources and the State Agency on Energy Efficiency and Energy Saving.

Legal framework

The electricity industry in Ukraine is primarily regulated by the Electricity Market Law and other less complex laws and regulations, including, but not limited to:

- Law of Ukraine "On Combined Production of Heat and Electrical Energy (Cogeneration) and Use of Waste Power Potential";
- Law of Ukraine "On Alternative Energy Sources";
- Law of Ukraine "On Amendment to Certain Laws of Ukraine on Improving the Conditions for Supporting the Production of Electricity from Alternative Energy Sources";
- Law of Ukraine "On Environmental Impact Assessment";
- NEURC Resolution "On Transmission System Code";
- NEURC Resolution "On Distribution System Code";
- NEURC Resolution "Code of Commercial Accounting for Electric Power";
- NEURC Resolution "On Market Rules";
- NEURC Resolution "On Approval of Certain Normative Acts Regulating the Activity of the Guaranteed Buyer and Electricity Offtake under the FiT";
- CMU Resolution "On Approval of the Procedure for Electronic Auctions for the Sale of Electricity under Bilateral Contracts and the Procedure for Selection of Auction Organizers Authorized to Conduct Electronic Auctions for the Sale of Electricity under Bilateral Contracts";
- NEURC Resolution "On Day-ahead and Intraday Market Rules"; and
- NEURC Resolution "On Retail Market Rules".

Implementation of EU directives

On 6 June 2019, the Parliament ratified the updated Annex XXVII Energy Cooperation including Nuclear Issues to the EU-Ukraine Association Agreement ("Annex"), which aims at bringing Ukrainian electricity sector regulations in line with key parts of the EU acquis or body of law. This Annex provides for a number of EU Directives and Regulations in the electricity sector, among others, which Ukraine should implement:

- Third Electricity Directive;
- ERS Directive (Renewable Energy Directive);
- New Electricity Regulation;
- REMIT;
- Security of Electricity Supply and Infrastructure Investment Directive;
- Inter-transmission Guidelines Regulation;
- Electricity Markets Regulation;
- Network Code on Demand Connection Regulation;
- Grid Connection Regulation;
- Network Code Requirements Regulation; and
- Statistics on Natural Gas and Electricity Prices Regulation.

In addition, in 2017, the Parliament adopted the Electricity Market Law to implement the Third Electricity Directive, the New Electricity Regulation, and the Security of Electricity Supply and Infrastructure Investment Directive. As of 1 July 2019, the Electricity Market Law became fully effective.

A.2 Third party access regime

Equal access to the electricity market and to the services of network operators is guaranteed to generating companies and electricity suppliers that have obtained relevant licences. However, if the limit of operational safety of the integrated power system ("IPS") of Ukraine is reached, the TSO should take measures to temporarily suspend the issuance of technical conditions and/or provide written opinions/recommendations on fulfilling technical measures to ensure proper and sustainable operation of electricity facilities in the IPS of Ukraine and/or in its relevant parts.

Connection services are provided by the DSOs on a 'turn-key' basis for a fee, with the price depending on the type of connection (ie standard or non-standard). The Transmission System Code and Distribution System Code constitute key regulatory framework on connection matters.

A.3 Market design

Starting from 1 July 2019, a single-buyer electricity market was replaced by a liberalised electricity market, which comprises of the sub-markets such as: (i) the market of bilateral agreements (over-te-counter ("OTC") market), (ii) the day-ahead market, (iii) the intraday market and (iv) the balancing market, and also (v) the ancillary services market, as well as (vi) the retail electricity market were introduced.

Bilateral agreements (OTC) market

The market of bilateral agreements is based on forward sale/purchase contracts between the following market participants: (i) producers; (ii) suppliers, (iii) the TSO, (iv) DSOs, (v) traders, (vi) the Guaranteed Buyer and (vii) customers.

Day-ahead market

The day-ahead market is a power exchange where market participants submit their bids on a competitive basis. The bidding auction takes place one day before the actual delivery of electricity.

Intraday markets

The intraday market is a supplementary market, where the electricity is traded continuously after there is no more bidding on the day-ahead market. On the intraday market, market players may update their trading positions based on the existing supply and demand and current system conditions, as they approach real time.

Balancing market

In the balancing market, the TSO balances the supply and demand of electricity with the help of balancing services providers. To become a balancing services provider, the market participant must enter into the balancing market participation agreement with the TSO. The TSO carries out the purchase and sale of balancing electricity based on bids from the balancing services provider and the actual activations of the corresponding hour. Electricity is purchased and sold in the balancing market to ensure real-time balance between production volume, imports, exports and consumption.

Ancillary services market

In the ancillary services market, the TSO is expected to enter into agreements with market participants for the purchase of the relevant electricity ancillary services (such as frequency containment reserve, automated and manual frequency restoration reserve and restoration reserve services) to comply with the reliability requirements of the power system of Ukraine.

Retail market

In the retail market, consumers purchase electricity directly from suppliers. Qualified customers should be able to purchase electricity at their discretion from independent suppliers or guaranteed suppliers (at contractual prices), while non-qualified customers will only be able to purchase from guaranteed suppliers (at the regulated prices established by the NEURC).

A.4 Tariff regulation

Under the liberalised electricity market rules, electricity producers are able to trade electricity on any of the markets, save for certain regulatory limitations, at competitive prices. A separate regime applies to electricity produced from RES, which may be traded at the green tariff or the auction prices.

Since 1 July 2019, due to the introduction of a new electricity market model in Ukraine, the two separate tariffs for TSO services were introduced: a tariff for electricity transmission services, and a tariff for dispatch (operational and technological) control services. Both tariffs are paid by DSOs, consumers, producers, traders, electricity suppliers and other electricity market participants. Both tariff levels are established by the NEURC annually on a cost recovery basis.

A.5 Market entry

Mandatory licensing is established for activities such as generation, transmission, supply of electricity to a consumer, trading and conducting functions of the Market Operator or the Guaranteed Buyer. Combined power and heat generation, heat power generation at TPPs or at facilities using RES, transportation of thermal energy by main and distribution thermal grids, as well as supply of thermal energy are also subject to licensing.

The Regulator issues licences for an unlimited term. In the event of a breach of licensing conditions by the licensee, the Regulator may revoke the licence.

Licences issued by the Regulator do not cover activities related to the construction of generation facilities, transmission and distribution networks.

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The Electricity Market Law imposed public service obligations ("PSOs") on:

- the Guaranteed Buyer, the universal services suppliers, the TSO to increase the share of electricity produced from RES for the period of the "green tariff" and auctions regime support granted to RES producers; and
- the TSO (until 1 July 2024) and producers engaged in combined heat and power generation at TPPs, the decision of which was made by the Government, to increase the efficiency of combined heat and power generation. At the same time, to date, no producer engaged in combined heat and power generation has claimed any amounts as the form of the agreement with the TSO (under which they could receive compensation) was not approved.

To cover the Guaranteed Buyer's reasonable expenses for performing the PSO function for the purchase of electricity from the RES producers under the "green tariff" or the auction prices, the Guaranteed Buyer ensures an increase in the share of electricity produced from RES.

With effect from 1 October 2021, the Government also imposed a new PSO mechanism providing for moving from commodity-based PSO to the financial PSO, under which in respect of PSOs:

- universal services suppliers must supply electricity to household customers at regulated prices;
- universal services suppliers must provide the Guaranteed Buyer with services to ensure the availability of electricity for domestic consumers;
- Guaranteed Buyer must provide producers with services to ensure the availability of electricity for domestic consumers and to compensate the universal services suppliers for any reductions incurred between the fixed tariff for households and market price of electricity;
- DSOs must purchase a base load from Energoatom in the Integrated Power System of Ukraine trade zone to cover their own technological expenses at a price of 1,700UAH/MWh (the price is subject to quarterly indexation to the industrial producer price index); and
- Energoatom and Ukrhydroenergo must compensate the Guaranteed Buyer for losses incurred in context of universal services suppliers deficit coverage without electricity flows.

In case of default by the universal services supplier, the last resort suppliers are obliged to supply electricity to household customers at regulated prices..

Smart metering

Under the applicable regulatory framework, there are no regulations on smart metering. However, Ukrenergo plans to implement the smart grid system in Ukraine to improve the effectiveness and reliability of electricity supply, significantly increase faultless performance of power grids and protect the environment.

Electric vehicles

Ukrainian law currently provides for certain tax incentives (in particular, a value added tax ("VAT") exemption) with respect to the import into Ukraine of vehicles equipped exclusively with electric motors.

Pursuant to requirements of the ERS Directive, two laws aimed at promoting development of electric transport in Ukraine were adopted in August 2021.

In particular, the adopted laws temporarily:

- enable taxpayers to include expenses related to the purchase of electric vehicles ("EVs") for a tax discount and reduce their taxable income;
- extend VAT relief for components imported to the customs territory of Ukraine for the manufacture of EVs;
- relieve from taxation the profit from sales of own-produced lithium, lithium-ion (lithium polymer) batteries, chargers for these batteries and own-manufactured EVs;
- relieve from excise duty car bodies imported to the customs territory of Ukraine for the manufacture of EVs.

The adopted laws also relieve from import duty until 1 January 2029 components imported to the customs territory of Ukraine for the manufacture of EVs.

A.7 Cross-border interconnectors

On 16 March 2022, the power system of Ukraine was fully synchronised with the Continental European network (ENTSO-E).

Electricity import, transit and export are regulated by the Electricity Market Law, which aims to implement the New Electricity Regulation. Also, as Ukraine has ratified the Energy Charter, networks for electricity transit are provided on a non-discriminatory basis with due regard to technical limitations.

Access to the cross-border capacities of interstate electricity networks are obtained at auctions, which are held by the TSO. The TSO makes every effort to achieve the integration of Ukraine's energy system into ENTSO-E, which includes the introduction of joint auctions with neighbouring TSOs of ENTSO-E and Moldova to distribute the capacity of interstate crossings.

B. Oil and gas

B.1 Industry structure of the market

Ukraine has made significant progress in regulating its upstream sector and has become much closer to aligning its market with European standards. The Law of Ukraine "On the Natural Gas Market" ("Natural Gas Market Law") created a framework for the development of a liberalised and competitive gas market, where each user can freely choose suppliers and purchase gas at market prices.

Key market players

State-owned NJSC NaftoGaz, is the largest energy company in Ukraine, with operations spanning natural gas, oil and gas condensate exploration and production, gas and oil storage and oil transmission, gas and oil wholesale and retail trading, as well as refining and sale of petroleum products. Until January 2020 it was a vertically integrated company engaged in the full cycle of gas and oil exploration operations: drilling, development and production; transport, refining and storage; and supplying natural gas and liquefied petroleum gas (LPG) to consumers. However, to meet the requirements of the TEP, Ukraine unbundled Naftogaz by transferring the Gas Transmission System Operator of Ukraine (GTSOU) from NaftoGaz to state-owned Main Gas Pipelines of Ukraine. GTSOU operates the gas transmission trunk lines but Naftogaz continues to operate the gas storage facilities since unbundling. Regional gas distribution and supply companies hold permits from UkrTransGaz to transport gas through main and regional transmission pipelines and are responsible for gas distribution.

State participation in oil and gas exploration and production activities is carried out by NJSC Nadra Ukrayny, which conducts geological surveys, provides resource and economic estimates and enters into joint-venture agreements with private investors. NaftoGaz and its subsidiaries hold the largest share of all oil and natural gas produced in Ukraine. UkrGazVydobyvannya is the company affiliated with NaftoGaz responsible for gas production and LPG/compressed natural gas (CNG) production. Gas production of the numerous independent oil and gas producers operating in Ukraine has been increasing steadily. UkrTransNafta, another subsidiary of NaftoGaz, operates the oil pipeline system. UkrNafta is the main oil producer and also produces a small amount of gas.

Regulatory authorities

The regulatory authorities include:

- The Ministry of Energy, which is responsible for the formation and implementation of state policy in oil and gas industry, determines the priorities in the development of the energy sector;
- The Ministry of Ecology and Natural Resources, which is responsible for the environmental protection and ecological safety;
- The State Geology and Subsoil Service, which issues special permits for subsoil use (including permits for subsoil areas containing oil and gas reserves), suspends, cancels and reissues such permits; and
- The NEURC, which is a permanent central executive body with a special status in charge of, among others activities related to transportation, distribution, storage (injection, offtake), and supply of natural gas, liquefied natural gas ("LNG") installation services, as well as activities related to the transportation of oil, oil products and other substances by pipelines.

Legal framework

The principal legislative acts governing mining and oil and gas exploration activities in Ukraine are the Code on the Subsoil ("Subsoil Code"), and the Laws of Ukraine "On Oil and Gas," "On Production Sharing Agreements," "On Mining in Ukraine", Law of Ukraine "On Pipeline Transport" and "On Gas (Methane) of Coal Fields."

The Natural Gas Market Law regulates the midstream and downstream oil and gas operations. The Law of Ukraine "On Ensuring Transparency in Extractive Industries" defines the disclosure obligations of the upstream market participants and the relevant state authorities.

The Subsoil Code defines the subsoil as 'a part of the earth's crust underlying the land surface and the bottom of bodies of water and stretching to the depths accessible for geological exploration and development'. The subsoil is the exclusive property of the people of Ukraine and may be granted to Ukrainian and foreign legal entities and individual entrepreneurs for use only.

On 1 April 2018, the Law of Ukraine on Amendments to Certain Legislative Acts of Ukraine Regarding Deregulation of the Oil and Gas Industry became effective. The law significantly reduces the number of permits required for the exploration and production of oil and gas.

Under Ukrainian law, the following activities on the oil and gas market require licences:

- transportation of oil and oil products through principal Ukrainian pipelines; and
- commercial operations on the natural gas market related to the transportation, distribution, storage and supply of natural gas and LNG installation services.

The State Geology and Subsoil Service is working on a new modern Subsoil Code. It is expected to create an electronic subsoil user account, the procedure of organising auctions selling special extraction permits and production sharing agreement contests, the possibility of alienating the subsoil usage rights to third parties, and other clear procedures and new institutes (which are known in Europe and the US, but are new for Ukraine). These changes should promote further foreign investment into the oil sector.

Implementation of EU gas directives

On 6 June 2019, Ukrainian Parliament ratified Annex XXVII to the EU-Ukraine Association Agreement, which provides for a number of EU Directives and Regulations in the oil and gas sector, among others, which Ukraine should implement.

EU Gas Directives and Regulations:

- Third Gas Directive;
- New Gas Regulation;
- Safeguard of Security of Gas Supply Directive;
- Network Code Regulation;
- New Gas Network Code Regulation; and
- Network Code on Tariff Structures Regulation.

B.2 Third party access regime to gas transportation networks

The Natural Gas Market Law provides for the independence of the TSO and for the ownership unbundling model, which aims to ensure non-discriminatory access of all interested market players to the gas transportation networks. The gas TSO must provide access to the system to market participants through a network connection agreement.

The procedure to access the gas distribution system is provided by the Gas Distribution System Code. The operator of the gas distribution system enters into agreements with customers (individuals or legal entities) to connect them to the system. The Gas Distribution System Code provides for equal rights of access to the gas distribution system to all market participants. Market participants and customers enter into agreements on distribution of natural gas with the gas DSOs.

B.3 LNG terminals and gas storage facilities

Ukrtransgaz manages one of the largest underground gas storage facilities infrastructure in Europe with 11 storage facilities throughout Ukraine. Overall capacity of the underground gas storage facilities equates to 31 billion cubic metres. The company provides access to storage facilities to market participants and customers. Resolution of the Regulator No. 1150 dated 24 June 2020, establishes tariffs for services on storage (injection, withdrawal) of natural gas in the underground storage facilities of Ukrtransgaz. The operator of the gas storage facility must act in a non-discriminatory manner when entering into agreements on storage (injection, withdrawal) with customers.

Market participants also have equal rights in terms of access to LNG facilities. The operators of the LNG facilities provide access to the facilities on the basis of agreements, similar to the procedure for receiving access to underground storage facilities.

B.4 Tariff regulation

The Regulator establishes tariffs for the transportation and storage of oil and natural gas. On 24 December 2019, the Regulator defined tariffs for the points of entry to and exit from the Ukrainian gas transmission system for the period of 2020-2024, which became effective on 1 January 2020; the tariffs for storage services (injection, withdrawal) of natural gas in underground gas storages of Joint Stock Company Ukrtransgaz on 24 June 2020; and the methodology for the setting of tariffs for the transportation of oil (petroleum products) by main pipelines on 25 May 2017.

B.5 Market entry

As part of the Ukrainian gas market integration into the corresponding EU energy market, on 1 January 2020, Ukraine effected the separation of its natural gas transmission operations from the extraction and supply operations ("Unbundling") and GTSOU became fully operational. The Unbundling facilitates the non-discriminatory access to the Ukrainian GTS for all market participants and was effected based on the independent system operator model in line with the Government's Resolution "On Unbundling of Natural Gas Transmission Activity and Enabling Activity of Transmission System Operator" and the Law of Ukraine "On Amendments to Certain Laws of Ukraine in Connection with the Separation of Natural Gas Transportation Activities". Additionally, third parties may enter into product sharing agreements with licensed market participants to invest in the production of oil and gas. For gas transportation, distribution and storage, customers and market participants have the right to enter into a network connection agreement with the gas transmission system operator, an agreement on distribution of the natural gas with the gas distribution system operator and agreements on storage (injection, withdrawal) with the operator of the gas storage facility.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

According to the Natural Gas Market Law, special obligations may be imposed on market participants to ensure public interests in the functioning of the natural gas market. On 19 October 2018, the Government passed the Resolution on Imposing Special Obligations of Natural Gas Market Participants for Ensuring Social Interest in the Process of Natural Gas Market Operation (PSO obligations). The resolution imposed special obligations on Ukrgasvydobuvannya to sell all marketable natural gas to Naftogaz, and Naftogaz was obliged to sell such gas at a regulated price to certain customers, including heat-generating entities. The PSO obligations of Naftogaz terminated on 20 May 2021. The gas-supplying entities fulfilling PSO obligations are entitled to compensation from the State.

Smart metering

The Law of Ukraine on Ensuring of Commercial Accounting of Natural Gas provides for an obligation on gas operators to install individual meters for consumers; gas supply to customers is subject to individual meters being installed. Meters should be installed for all customers by 1 January 2023. The Regulator supports the implementation of smart metering in Ukraine, which will supply the statistics for the actual amount of gas consumption.

B.7 Cross-border interconnectors

On 31 December 2019, Naftogaz, GTSOU and Gazprom entered into a set of agreements to continue Russian gas transit through Ukraine until 2024. The package includes interconnection agreement between GTSOU and Gazprom and agreement on organisation of transit between Naftogaz-Gazprom settling conditions and transit volumes. The new agreement envisages at least 225 billion cubic metres of gas transition based on "pump-or-pay" principle (unlike the "take-or-pay" principle incorporated in the previous contract). The agreement may be prolonged for ten more years.

Ukraine also enhances cooperation with the European TSOs. In 2015, Ukrtransgaz and Hungarian TSO FGSZ signed interconnection agreement (interconnection points in Berehove, Ukraine and Beregdaróc, Hungary).

In 2016, Ukrtransgaz and Romania's National Gas Transmission Company Transgaz signed interconnection agreement (interconnection points in Orlivka, Ukraine and Isaccea, Romania).

In December 2019, GTSOU signed interconnection agreements under EU standard business rules with FGSZ (Hungary), with Moldovatransgaz LLC, and Moldovagaz JSC (Oleksiivka, Grebeniki, Caushan, Ananiev, Lymanske interconnection points), and with Slovak TSO Eustream (Budintse and Uzhgorod-Velka Kapusany interconnection points).

In June 2020, GTSOU and Polish Operator Gazociagów Przesyłowych GAZ SYSTEM S.A. concluded new interconnection agreement uniting existing two interconnection points Drozdowicze and Hermanowice into one single virtual interconnection point.

C. Energy trading

C.1 Electricity trading

See section A.3 for electricity trading rules applied in the industry. More specifically, with respect to the bilateral trading market, the Electricity Market Law does not provide for the establishment of a central platform and trading takes place over-the-counter. The Electricity Market Law also does not establish a specific form of a contract for bilateral trading and the parties may negotiate the terms of their contracts without any limitations (as, for example, could have been provided by a model contract).

In addition, electricity trading can occur on one of the commodity exchanges. For example, the Ukrainian Energy Exchange is a centralised trading platform for the sale and purchase of electricity under bilateral agreements. Certain state-owned companies, which are required by operation of law to sell their electricity on electronic auctions, other market participants that wish to sell electricity on a voluntary basis, as well as Energoatom, Ukrhydroenergo (which are subject to the public service obligations) participate in the auctions held by the Ukrainian Energy Exchange.

Trading on other markets is done based on model forms of contracts, which are established by law.

The balancing market is the last stage for electricity trading. It plays an essential role, as production and consumption levels must match during the operation of electric power systems, to avoid storing large quantities of electricity, which is not economically convenient.

In the balancing market, the purchase and sale of electricity is carried out to ensure a real-time balance of production, import, export, consumption of electricity and settlement of imbalances. The mechanism of the balancing market, and the pricing, is determined by the Market Rules approved by the NEURC.

C.2 Gas trading

Unbundling of the gas TSO provides for implementation of principles established in EU directives and for the liberalisation of the natural gas market. Obtaining access to capacity and the provision of services for transportation, including services on regulation of the daily imbalance, are included in the natural gas transportation service and are provided under the transportation agreement between the customer and the TSO. The TSO is responsible for regulation of any imbalance of the system, which is calculated as the difference between the volumes of natural gas entering through the entry points and the volumes of natural gas exiting through the exit points, on the basis of actual data received through the allocation procedure, in the context of transmission service customers.

The Natural Gas Market Law envisages the concept of supplier of last resort, who may not refuse to enter into contracts with private consumers if the previous supplier could not continue its operation.

D. Nuclear Energy

Ukraine is heavily dependent on nuclear energy and currently has 15 reactors located at four nuclear power stations ("NPS") generating about half of the state's electricity. All Ukrainian NPS are operated by Energoatom. Ukraine is the eighth in the world in terms of installed NPP capacity. Following the results of 2017, Ukraine was third in the world in the share of NPP electricity in the total electricity production in the country.

According to the Ministry of Energy, the electricity produced by NPPs constituted 50.5% of Ukraine's total output as of February 2021.

On 31 August 2021, Energoatom signed a memorandum with Westinghouse for the construction of new nuclear energy reactors in Ukraine.

On 2 September 2021, Energoatom signed a memorandum with NuScale Power anticipating the construction of small modular reactors ("SMR") in Ukraine. NuScale will provide Energoatom with its expertise on SMR technology, assist with the assessment of proposed construction sites, project development, cost research, technical analysis, licensing, engineering and design.

The general provisions on nuclear waste management in Ukraine are provided by the Law of Ukraine on Radioactive Waste Management. This law allocates the competence in the area of radioactive waste management between various public authorities, and sets out the rights and obligations of individuals and legal entities when dealing with radioactive waste. In particular, it provides that only those persons that obtain the respective permit can manage radioactive waste as a business activity.

The updated Annex XXVII Energy Cooperation including Nuclear Issues to the EU-Ukraine Association Agreement provides for a number of EU Directives in the nuclear energy sector, which Ukraine should implement, including:

- Exposure to Ionising Radiation Directive;
- Supervision and Control of Radioactive Waste and Spent Fuel Directive;
- Euratom Directive;
- Nuclear Safety Directive; and
- Spent Fuel and Radioactive Waste Directive.

On 10 November 2020, the State Inspectorate for Nuclear Regulation obtained the status of observer at the European Nuclear Safety Regulators Group (ENSREG). This allows Ukraine to better integrate into the European network of regulators, participate in expert discussions of new technologies and processes, as well as to improve cooperation in the field of nuclear safety and radioactive waste management.

E. Upstream

Exploration and production are subject to obtaining special permits, which are issued by the State Geology and Subsoil Service. The special permits that may be issued for the use of oil and gas bearing subsoil include permits for:

- geological studies of oil and gas bearing subsoil, including pilot production;
- geological studies of oil and gas bearing subsoil, followed by oil and gas production (industrial development of fields);
- oil and gas production (industrial development of fields); and
- construction and operation of underground oil and gas storage facilities.

Subsoil users have the right to carry out geological studies, undertake the comprehensive development of mineral deposits and other works in accordance with the provisions of a special permit or production sharing agreement, and to handle minerals produced from such deposits unless otherwise provided by statute or the applicable special permit. Subsoil users must use the subsoil for its intended purpose, to ensure a comprehensive geological study and to ensure the sustainable use, and protection of, the subsoil.

Naftogaz group (Ukrgasvydobuvannya and Ukrnafta) carried out most of the exploration and production of oil and gas in Ukraine. In 2020, Naftogaz extracted 1.95 million tonnes of oil and gas condensate, and produced 15.3 billion cubic metres of natural gas (76%). Private companies accounted for the rest 24% of gas production or 4.9 billion cubic metres.

F. Renewable Energy

F.1 Renewable energy

The renewable energy sector is currently in a transition period in Ukraine. The law provides for both auction and non-auction subsidies. Both imply that the Guaranteed Buyer must buy out generated energy at the established tariff. The legislation is transitioning towards auctions and stepping back from the green tariff.

The relevant changes were introduced in April 2019 by the Law of Ukraine on the Amendment of certain laws of Ukraine on facilitation of competitive conditions for the production of energy from alternative sources.

Under this law, business entities that produce solar or wind energy must participate in auctions if their capacity exceeds 1MW and 5MW, respectively. Other business enterprises (subject to certain restrictions by types of energy) may participate in auctions on a voluntary basis.

To date, the auctions system has not yet been launched.

The green tariff system remains in force for the following entities:

- facilities brought into operation prior to 1 January 2020;
- facilities having executed the pre-PPA with the Guaranteed buyer by 31 January 2019, provided they will be brought into operation within two years from execution of the pre-PPA (for solar plants) and within three years (for wind plants);
- solar plants with capacity less than 1MW; and
- wind plants with capacity less than 5MW or having less than three wind turbines.

F.2 Renewable pre-qualifications

The following documents are required for an auction pre-qualification procedure (the auction system has not been launched yet and the list of pre-qualifications may be updated closer to the launch).

To participate in the auction, the bidders must submit, among other things: (i) documents confirming secured land rights (title or land-use rights in respect of the land plot(s) suitable for development and maintenance of a power plant), (ii) executed grid connection agreement, and (iii) the irrevocable bank guarantee in favour of the Guaranteed Buyer in the amount of €5./kW.

F.3 Biofuel

The key legislative act regulating the production of biofuels is the Law of Ukraine on Alternative Types of Liquid and Gas Fuel, which establishes the concepts of conventional and alternative fuels, defines the categories of alternative types of fuel and provides free access to the biofuels market for all producers.

In 2015, amendments to the Law of Ukraine on Alternative Types of Liquid and Gas Fuel established the required percentage of biofuel in motor petrol produced or sold in Ukraine at 7%, starting from 1 January 2016.

The Tax Code of Ukraine provides for tax reductions in cases relating to the use of biofuel. In particular, it established a zero rate excise tax for bioethanol used for the production of certain types of fuel.

G. Climate change and sustainability

G.1 Climate change initiatives

In January 2020, the Ministry of Energy published Ukraine's 2050 Green Energy Transition Concept (Ukraine Green Deal) and presented it to EU officials as a commitment of Ukraine to meet the objectives of the European Green Deal. Overall, the concept focuses on reducing greenhouse gas ("GHG") emissions through improving energy efficiency and boosting the deployment of renewable energy.

In July 2018, Ukraine published its 2050 Low Emission Development Strategy. This strategy provides emission reduction pathways for the energy and industry sectors based on four scenarios containing different ambition levels of decarbonisation measures and policies.

G.2 Emission trading

Ukraine does not participate in the EU Emission Trading System ("ETS"). However, the commitment for establishing the national ETS is provided by Annex XXX to the Association Agreement between the EU and the European Atomic Energy Community and their Member States and Ukraine requiring Ukraine to implement certain provisions of the EU ETS Directive, including to:

- adopt the relevant legislation and designate the respective competent authority;
- establish the monitoring, reporting, verification ("MRV") and enforcement systems;
- establish a system for issuing GHG emissions permits; and
- issue the allowances to be traded domestically among installations in Ukraine.

The law on Basic Principles of Monitoring, Reporting and Verification of GHG Emissions, entered into force on 1 January 2021. Ukrainian authorities have indicated that Ukrainian integration into the ETS will not take place before 2025.

G.3 Carbon pricing

In 2017, the Natural Resources Ministry introduced the Low Emissions Development Strategy for the Period Until 2050, which is considered a solid basis for the development of carbon capture and storage ("CCS") systems. There are a number of other soft laws with the aim of cutting down carbon dioxide ("CO_2") emissions adopted by the Government, including The Framework of "Green" Energy Transition until 2050, the Renewed Strategy for Low-Carbon Development until 2050 etc.

In addition to these strategies and frameworks, there is the Law on the Basic Principles of Monitoring, Reporting and Verification of GHG, the Law on the Regulation of business activities concerning ozone-depleting substances and fluorinated GHGs.

Since 2011, Ukraine has a carbon tax that applies to CO_2 emissions from stationary sources in the industry, power, and buildings sectors. In November 2018, the Ukrainian parliament decided to steadily increase the carbon tax rate from January 2019 onwards. But even with this increase the rate remains below 1US$/tCO_2$ in 2020 and still is the lowest carbon price in the world. Moreover, those enterprises, that emit less than 5 tonnes of CO_2 per year, are not subject to carbon tax.

A registered draft law increasing carbon tax in three times as a part of a renewed eco-tax is still under discussion.

There is also a registered draft law that provides for the establishment of the Decarbonisation Fund aimed at funding projects for decreasing CO_2 emissions. This draft law also contains provisions on the increase of carbon tax.

G.4 Capacity markets

Neither the payments for long-reserves nor a separate capacity market (or capacity payments) have been implemented in Ukraine.

H. Energy transition

H.1 Overview

The energy transition is one of the obligations Ukraine took upon under the EU-Ukraine Association Agreement. On 21 January 2020, the Minister of Energy presented a draft concept of Green Energy Transition of Ukraine until 2050 developed in line with global energy tendencies and sets the following main goals:

- energy self-sufficiency and resistance to safety challenges;
- sustainable energy production and consumption; and
- a climate-neutral economy until 2070.

The main directions regarding anticipated decarbonisation are: energy efficiency and energy saving; renewable energy sources; waste management; innovative agriculture and forestry; digitalization of economic processes.

Decarbonisation of the energy sector should be ensured by a gradual "green" transition and a decrease in the share of extractive industries in the economy and export.

In the electric power industry, parallel processes of modernisation, reduction of GHG emissions and gradual reduction of coal generation through social acceptability should take place.

In the heat supply sector, it is expected to expand the use of highly efficient cogeneration and tri-generation. New cogeneration plants for district heating should primarily focus on the use of biomass and biogas.

H.2 Renewable fuels

The development of green hydrogen production (based on electrolysis of water using renewable electricity) is part of the Ukraine's chosen direction. The Ministry of Energy and more than 20 Ukrainian companies have joined the European Clean Hydrogen Alliance to coordinate efforts to develop hydrogen energy. According to estimates, Ukraine could establish at least 10GW of electrolysed hydrogen capacity by 2030. There is no demand yet in Ukraine for such volumes of hydrogen, so production is mainly being considered for export to the EU. Hydrogen produced in Ukraine could cover one-eighth of the capacity required by the EU to reduce GHG emissions. Ukraine is currently working on its National Hydrogen Strategy and expects to adopt it in the coming months. To date, there is no unified statutory act regulating hydrogen in Ukraine.

H.3 Carbon capture and storage

Absorption of CO_2 emissions due to carbon capture, storage and utilisation technologies is one of the measures provided for under the 2050 Low Emission Strategy of Ukraine. It is envisaged to increase the share of highly efficient cogeneration with a mandatory audit of the economic feasibility of its introduction in the regions of Ukraine, as well as to stimulate the development and use of carbon capture, storage and utilisation technology at large incinerators, to comply with Ukraine's International Commitments and improve the energy efficiency of the economy.

However, current priorities are focused on technologies for increasing coal-fired plant efficiency and emissions reductions rather than on carbon capture and storage.

H.4 Oil and gas platform electrification

Electrification of oil and gas operations is not yet regulated in Ukraine.

H.5 Industrial hubs

Ukraine has adopted a Law "On Industrial Parks" that provides for the creation, operation, and state support of industrial parks in Ukraine. Foreign investors in Ukraine can run businesses in industrial parks, as well as participate in their creation. An industrial park should be used for at least 30 years. The following types of activity are allowed within industrial parks of Ukraine: processing industries, industrial and/or household waste processing (except for waste disposal), scientific and technical activities, and information and telecommunications activities. Participants of an industrial park must acquire a right to a land plot and/or other real estate located within the territory of an industrial park and enter into an agreement with the management company on carrying out the economic activity within the territory of an industrial park in accordance with the industrial park concept. The law stipulates that initiators, participants and management companies of industrial parks, which are registered with the state register of industrial parks, are entitled to the following state incentives: full or partial compensation for interest rates on loans taken for equipping or carrying out business in industrial parks; financing of the construction, refurbishment, repair of engineering infrastructure for the development, equipping, and operation of industrial parks; compensation in respect of the costs incurred for connection to the engineering networks; and tax and customs benefits.

Additionally, the 2020 State Regional Development Strategy, the 2020 Concept of State Economic Programme of Industry Development and the 2020 Strategy of Small and Medium Business Development approved by the Government provide for the creation of scientific-innovative production clusters in high-technology industries and establishment of legislative framework for the procedure of funding (co-funding) of clusters.

H.6 Smart cities

Ukraine has a number of initiatives that bring together Ukrainian cities and amalgamated territorial communities, city government experts, representatives of Ukrainian technology companies and international businesses, public and non-profit organisations, scientific and academic communities to build smart urban infrastructure in Ukraine.

To transform Kyiv into a technologically advanced city, the deputies of the city council approved the Kyiv Smart City 2020 Concept. The concept includes an access to the open city budget, e-auction, e-petition, emergency road works map, e-application for kindergartens, and a number of other services etc.

In comparison, Vinnitsa, implemented such measures as: (i) the reconstruction of Kosmonavtiv avenue by creating separated cycle tracks, equipping it with modern street LED lighting, charging stations for gadgets, WIFI and a "Safe City" video surveillance system, (ii) switching public transport to over 70% of urban electric transport, (iii) the introduction of a Vinnitsa Citizen Electronic Card, a combination of a single electronic ticket, a municipal medical card, and many other services, (iv) a subsidies calculator, (v) an open budget established to promote transparency and free public access to information concerning the planning and execution of city budget, (vi) e-queue for civil service centres, etc.

One of the novelties introduced in Ternopil was the Open City Project initiated by the Eastern Europe Foundation, which provides opportunities to post opinions on drawbacks in the city, and track their correction. Other initiatives include the installation of a centralised video surveillance system of the city, an infographic representation of an open city budget, real-time public transport monitoring.

Initial steps towards smart cities, investment incentives and organisational issues are underway in Poltava, Lviv, Dnipro, Odesa, Kharkiv and other cities.

I. Environmental, social and governance (ESG)

ESG principles are yet to become mainstream for businesses in Ukraine, but DTEK is leading the charge in the energy utility sector. To achieve ESG objectives, DTEK has adopted twelve of the United Nations Sustainable Development Goals. It can be expected that DTEK's commitment will propel the entire Ukrainian business community towards the fulfilment of ESG standards. DTEK promotes incorporation of the "system value" concept in Ukraine, specifically integrating it into the national recovery strategy. The "system value" approach includes the expansion of renewables, grid upgrade and interconnection, the development of smart solutions and efficiency to create employment and make an important contribution to the post-Covid economic recovery, as well as helping to advance the clean energy transition.

Energy law in United Kingdom

Recent developments in the UK energy market

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Energy security and achieving independence from fossil fuel imports are at the forefront of recent UK energy policy in the wake of exposure worldwide to volatile energy markets and the continuing ambition to reach net zero by 2050.

In March 2023, the UK Government announced a comprehensive package of policy announcements relating to climate policy, energy security and green finance, which sets out a roadmap to reaching the Government's net zero ambitions by 2050 while achieving independence from fossil fuel imports.

The key proposals include a plan to 'Power up Britain' through investment into renewables and nuclear, and a green finance strategy that aims to encourage green finance and investment in the UK with the aim of becoming the world's first net zero-aligned financial centre.

Powering up Britain

The Powering up Britain Plan addresses the areas of energy security and net zero growth, setting out individual plans for each area, and focusing on four key areas of security:

- energy security, by achieving greater independence from fossil fuel imports;
- consumer security, by reducing energy bills and making wholesale electricity prices among the cheapest in Europe;
- climate security, by supporting industry in moving away from fossil fuels; and
- economic security, by reducing inflation, boosting growth and delivering high-skilled jobs.

The plan also contains the Government's response to the outcome of the Independent Review of Net Zero, which was commissioned to assess how the UK could better meet its net zero commitments in a manner that is affordable, efficient, pro-business and which takes into account the dynamic geopolitical landscape. The response includes, among other things, the publication by the Government of its 2023 Green Finance Strategy (see below).

Energy security

The Energy Security Plan sets out a roadmap towards making the UK more energy independent, secure and resilient, and seeks to build on the ambitions set out in the 2022 British Energy Security Strategy and the 2021 Net Zero Strategy for increasing the overall share of domestic energy production and reducing energy demand.

Domestic energy production

To increase the overall share of domestic energy production, domestic renewable electricity generation capacity is to be scaled up and, as the North Sea basin declines, domestic production of oil and gas is to be maximised.

The scaling up of domestic renewable electricity generation capacity includes putting an appropriate policy framework in place by 2024 to support investment in large-scale, long-duration electricity storage.

Key commitments under the Energy Security Plan include actions aimed at enhancing security of gas supply, such as:

- reviewing the role of gas storage in ensuring security of gas supply;
- assessing security of gas supply; and
- consulting on a policy framework for biomethane from 2026.

Buildings and industry energy demand

The plan also sets a new target of reducing energy demand from buildings and industry by 15% by 2030 through a £6.6 billion ("bn") integrated plan, with a further £6bn earmarked for the period 2025-2028. The proposed measures include aimed at improving the energy efficiency of buildings, products, business and industrial processes, and replacing fossil fuel heating with clean heat alternatives.

Net zero growth

The Net Zero Growth Plan sets out a delivery framework for the UK's long-term decarbonisation trajectory. The plan is set out with a view to improving the competitiveness of the UK economy and aims to:

- ensure a clean and secure supply of energy;
- reduce demand by increasing the energy efficiency of homes and businesses; and
- support the economy through the energy transition.

Some of the key proposals set out in the plan include:

- offshore wind: providing up to £160 million in funding for port infrastructure projects required to deliver floating offshore wind installations under a Floating Offshore Wind Manufacturing Scheme;
- solar: forming a taskforce to oversee delivery of 70GW of solar generation capacity by 2035;

- nuclear: setting up Great British Nuclear to deliver a new nuclear programme, starting with a competitive process to select the best Small Modular Reactor technologies (April 2023);
- hydrogen: confirming of the first winning projects from the £240 million Net Zero Hydrogen Fund and introducing new legislative powers to design the new hydrogen transport and storage infrastructure business models by 2025;
- carbon capture, usage and storage ("CCUS"): eight projects selected to move to Phase 2 of Track 1 of the Government's CCUS clustering process; commencing in 2023 a selection process to bring in further CCUS projects within the Track 1 clusters by 2030;
- sustainable aviation fuel ("SAF"): setting out, by way of consultation, full details of the SAF mandate policy;
- gas/electricity rebalancing: outlining a clear approach to gas/electricity rebalancing by the end of 2023 to 2024; and
- heat networks: extending capital support for low carbon heat networks to 2028, including £220 million for the Heat Network Transformation Programme ("HNTP") over the years 2025-2026 and 2026-2027. The Government is providing over £0.5bn investment in funds and programmes to improve existing heat networks and develop new ones.

The plan also sets out proposals for various national policy statements for consultation, including in the areas of:

- energy;
- renewable energy infrastructure;
- electricity networks infrastructure;
- natural gas electricity generating infrastructure; and
- natural gas supply infrastructure and gas and oil pipelines.

The plan also considers proposals on carbon leakage and addresses carbon budgets. A public consultation (open from 30 March 2023 to 23 June 2023) considers a range of policies on carbon leakage including the introduction of a carbon border adjustment mechanism ("CBAM"), mandatory product standards and other policy measures aimed at mitigating the risk of carbon leakage that may undermine domestic decarbonisation measures.

Carbon leakage refers to situations where for economic reasons relating to climate policies a business may transfer production to another country that has less stringent emission constraints. The proposals under the plan draw closely on the EU CBAM, which is set to apply from October 2023.

The delivery of carbon budgets is set out in a carbon budget delivery plan, which is a long-term dynamic plan for the 15-year transition to 2050 that takes a market-led approach. The carbon budget delivery plan is designed to adopt and change in line with future technological and economic changes in the energy sector.

2023 Green Finance Strategy

The UK Government has set an ambition to become the first global net zero aligned financial centre. The 2023 Green Finance Strategy sets out how the Government intends to mobilise the investment needed to meet its climate objectives and sets a target of raising at least £500 million of private finance annually by 2027 to support the achievement of the UK's environmental targets, rising to more than £1bn by 2030.

The strategy recognises that in order to achieve this target, central government, public finance institutions and local authorities all have a role to play in formulating clear policies to boost investor confidence, providing incentives to de-risk projects and assisting the private sector identify sound investment opportunities.

Detailed investment roadmaps for various areas in the energy sector are due to be published throughout 2023, including on offshore wind, hydrogen, CCUS and heat pumps. Funding and finance models for net zero projects are to be explored by Government ahead of the next spending review. The strategy also envisages work with the Green Finance Institute to explore how blended finance models can be used to more strategically mobilise private finance to support green objectives.

REMA

The exposure in recent years to volatile global gas markets prompted the Department for Energy Security and Net Zero ("DESNZ") (formerly the Department for Business, Energy and Industrial Strategy (BEIS)) to instigate a Review of Electricity Market Arrangements ("REMA"). The REMA aims to determine how electricity trading will change in Great Britain ("GB") and seeks to completely overhaul all non-retail electricity markets. A key outcome of initial consultations was that, while decoupling gas and electricity prices remains on the table, the Government will not adopt pay-as-bid pricing.

It is expected that the Government will push forward with steps to de-couple the market between fossil fuel and renewable generation and take steps to reform the capacity market. This may result in changes to the key market players, regulators and the legal framework currently in place.

Energy price guarantee

To deal with volatile wholesale markets, and the price exposure of consumers under the existing default tariff cap, an Energy Price Guarantee was introduced by the UK Government on 1 October 2022. The guarantee sets fixed amounts which suppliers may charge consumers both for standing charges and unit prices for a period of two years. The guarantee builds on the existing cap regime, under which a price cap is set for all domestic customers, not just those using prepayment meters.

Energy bill

In April 2022, the UK Government and Ofgem published their joint response to the Future System Operator ("FSO") consultation and set out a commitment to proceed with the nationalisation of the National Grid Electricity System Operator (NGESO) and the creation of the FSO.

The FSO could be established by, or in, 2024 depending on when the Energy Bill comes into law (see below). The objectives of the FSO include supporting the transition to net zero and ensuring the security of gas and electricity supply in GB.

The Energy Bill, first introduced to the UK Parliament on 6 July 2022, focuses on energy security in GB, in part through making provision for a FSO/Independent System Operator and Planner ("ISOP"). The proposed FSO/ISOP will be a fully independent system operator and, among other things, will undertake the planning for the electricity and gas systems, and will be responsible for long-term forecasting and market strategy functions.

The Energy Bill is a significant piece of the proposed legal framework in GB pursuant to the latest REMA arrangements to further change the electricity market.

In addition to making provisions on energy production and security, the Bill makes provision for regulation of the energy market, licensing of carbon dioxide transport and storage, and commercial arrangements for CCUS and hydrogen production. The Bill also makes provision on new technology for, among others, low-carbon heat schemes and hydrogen grid trials, and for amendments to the Petroleum Act.

Under the proposed amendments to the Petroleum Act, the Secretary of State is provided powers to create a charging scheme that could cover any of the statutory functions undertaken under part 4 of the Petroleum Act, including activities carried out after approval of a decommissioning programme. Part 4 provides a framework for the orderly decommissioning of disused offshore installations and offshore pipelines on the UK continental shelf. The charging scheme would specify the functions for which a charge can be applied.

The Bill provides for the North Sea Transition Authority ("NSTA") to have stronger powers when companies are subject to a change of control. The proposed amendments would require a licensee to apply to the NSTA for consent, in writing, at least three months prior to the desired date of the change of control. A licensee undertaking a change of control without the consent of the NSTA could result in its licence being revoked.

As of June 2023, the Bill continues to progress through parliament.

Overview of the legal and regulatory framework in United Kingdom

A. Electricity

A.1 Industry structure

Nature of the market

The market in Great Britain (England, Wales and Scotland) ("GB") is fully liberalised.

Key market players

Amongst the biggest electricity generators in the UK are Scottish Power, SSE, EDF, RWE, Drax, Uniper, Orsted, EEX and EPH. In recent years there has been an increase in small independent generators joining the electricity generation market.

There are four separately owned and operated transmission networks in the UK. In England and Wales, the National Grid owns and operates the transmission network through its subsidiary the National Grid Electricity Transmission plc ("NGET"). Northern Ireland Electricity Networks Ltd owns the transmission network in Northern Ireland, and in Scotland there are two systems, owned by SP Transmission plc (a subsidiary of SP Energy Networks) and Scottish Hydro Electric Transmission plc (part of the SSE plc Group).

National Grid operates the transmission system in Great Britain through its subsidiary National Grid Electricity System Operator ("NGESO") as the Electricity System Operator ("ESO"), a role that is split from role of Transmission Owner ("TO").

Distribution networks are also owned by SP Energy Networks, the SSE Group, UK Power Networks, Western Power Distribution, Northern Powergrid, Electricity North West, and Northern Ireland Electricity Networks. Ofgem and the Department for Energy Security and Net Zero ("DESNZ") (then Department for Business, Energy and Industrial Strategy ("BEIS")) have published a plan on a smart, flexible energy system (the "Smart Systems and Flexibility Plan"), which, among other things, envisages the role of distributors evolving and becoming Distribution System Operators ("DSOs") where they are more active managers of their networks in order to facilitate integration with the National Grid as the TSO.

Regulatory authorities

The Gas and Electricity Markets Authority ("GEMA") regulates the power and onshore gas industries in GB and was created under the Utilities Act 2000. GEMA acts through Ofgem (ie the Office of Gas and Electricity Markets).

Ofgem has powers under, among others, the Electricity Act 1989 ("Electricity Act"), the Gas Act 1986, the Energy Acts ("EA") 2004, 2008, 2010, 2011 and 2013, and the Electricity and Gas (Market Integrity and Transparency) (Enforcement etc) Regulations 2013. The equivalent body in Northern Ireland is the Utility Regulator (the Northern Ireland Authority for Utility Regulation ("NIAUR")).

Ofgem's main objective as electricity and gas regulator is to protect the interests of existing and future consumers in relation to electricity conveyed by distribution or transmission systems and gas conveyed through pipes. Consumer interests are taken to include lower bills, reduced environmental damage, improved reliability and safety, and an overall better quality of service.

One of Ofgem's principal roles is to set the price control for the monopoly activities of gas and electricity transmission and distribution businesses (both licensed and unlicensed).
The promotion of competition is also a key objective. Ofgem is required to have regard to: (i) securing that all reasonable demands for electricity and gas are met; (ii) the need to secure that licence holders can finance certain regulated activities; and (iii) the need to contribute to the achievement of sustainable development.

Ofgem has powers to investigate and prosecute criminal offences under the Electricity and Gas (Market Integrity and Transparency) (Criminal Sanctions) Regulations 2015 and the Electricity Act. Ofgem can also impose financial penalties of up to 10% of a licence holder's turnover and issue orders for securing compliance for breaches of licence conditions. Ofgem's Statement of Policy with respect to Financial Penalties and Consumer Redress[1] outlines the criteria used to evaluate breaches and the relevant procedures.

Ofgem also has concurrent powers with the Competition and Markets Authority ("CMA") to enforce the Competition Act 1998 and, for infringements prior to the end of the Brexit transition period, Articles 101 and 102 of the Treaty on the Functioning of the European Union in the electricity and gas sectors. Ofgem can impose directions and penalties of up to 10% of a company's applicable worldwide turnover for competition breaches.

Legal framework

The other key legislative provisions for the electricity sector in GB are set out in the Electricity Act (as amended and supplemented) and the Third Energy Liberalisation package[2].

Under the Electricity Act, it is an offence to carry out any of the activities of electricity generation, transmission, distribution, interconnector operation, supply or the provision of a smart meter communication service, without a licence granted by Ofgem, or an exemption. The exemptions to the licensing regime apply mainly to small-scale generation, distribution and supply. Licence applications are submitted to Ofgem, which grants the licences and enforces compliance with licence conditions.

The enactment of the Electricity and Gas (Internal Markets) Regulations 2011 extended Ofgem's enforcement powers to cover unlicensed supply and distribution activities. This continues to apply as retained EU law in GB as of 1 January 2021, whereas Northern Ireland remains subject to the EU law version subject to the Northern Ireland Protocol.

Implementation of EU electricity directives

Following the UK's departure from the EU ("Brexit"), much of EU-derived legislation concerning the electricity industry continues to apply and have effect in domestic law by way of the European Union (Withdrawal) Act 2018. However, there has been and will no longer be any further implementation beyond 31 December 2020.

Under the Electricity and Gas (Internal Markets) Regulations 2011 changes were introduced to implement parts of the Third Energy Liberalisation package into UK legislation. These Regulations: (i) designated Ofgem as the National Regulatory Authority ("NRA") for GB; (ii) enhanced the level of information provided to customers; (iii) reduced the time it takes for customers to switch suppliers; (iv) altered the licence modification and appeals process; (v) implemented the unbundling of energy supply and production from network operators; (vi) included a procedure for TSOs to certify independence; and (vii) introduced a third party access regime for licence exempt distributors.

The Regulations also introduced greater regulation for those exempt from the requirements to hold a distribution or supply licence.

Subsequent Electricity and Gas (Internal Markets) Regulations in 2014 and 2017 have implemented further European legislation, eg in relation to capacity allocation and congestion management. The 2014 and 2017 Regulations have not been repealed following the end of the Brexit transition period and are therefore also retained EU law in GB, along with a 2019 Regulation of the same subject matter, which deals with third country interconnectors and new network codes and guidelines specific to GB among other things.

A.2 Third party access regime

Licensed electricity distributors have a duty under the Electricity Act to connect a person who requests a connection to their distribution system. The distributor or Distribution Network Operator ("DNO") is obliged to provide standard terms and to quote charges for a connection based on a published connection charging statement. In addition, certain licence-exempt electricity distributors are required to allow third party supply access following the Electricity and Gas (Internal Markets) Regulations 2011.

In GB, electricity is traded bilaterally between suppliers and generators. The governance arrangements of GB's electricity balancing and settlement is set out in the Balancing and Settlement Code ("BSC"), which is administered by Elexon, an industry body that manages electricity trading in England and Wales.

The balancing mechanism is used by National Grid to accept offers to increase or decrease generation or consumption depending on demand. Licensed distributors, licensed suppliers and certain generators enter into a multilateral Distribution Connection and Use of System Agreement ("DCUSA"), which forms the contractual arrangement for the payment of system use charges by each supplier (or generator) to the relevant distributor and a standard set of connection terms for end customers that will apply in the absence of a bespoke bilateral connection agreement.

Distributors are obliged under their distribution licence to provide certain services for the industry. These services are set out in the Retail Energy Code ("REC")[3], which replaced the Master Registration Agreement ("MRA") on 1 September 2021. The REC combines the former MRA obligations with other operational codes and the Supply Point Administration Agreement. The REC was created following consultations by Ofgem on its proposal to implement a faster, more reliable switching service for domestic electricity and gas via a singular dual-fuel code. Under the REC, both licensees and non-licensees can propose modifications, access data and services. The managerial function of the code has moved away from a self-governance model supervised by Ofgem (as it was under the MRA) to an empowered code manager function.

Generators and customers wishing to have a direct connection to the transmission system must become a party to the Connection and Use of System Code ("CUSC"), which provides the legal framework for connections to, and use of, the transmission system. All licensed generators and suppliers are required to be parties to the CUSC under the terms of their licence and to comply with the Grid Code. The CUSC also sets out the methodologies used to calculate the National Grid's connection charges for connection to, and use of, the transmission system.

Following consultation in 2022, Ofgem published its minded-to decisions on electricity network access and forward-looking charges including[4]:

- Reforming forward-looking charges charged by transmission and distribution networks to improve signals to users to make better use of existing network capacity and reforming network access arrangements to clarify access rights and choices. Transmission network use of the system ("TNUoS") charges are paid by the generator and incentivise generation closer to demand. Though initially expected to be reviewed, TNUoS charges were removed from the scope of the Significant Code Review ("SCR") and will be reviewed separately. Ofgem has asked NGESO to lead task forces on future arrangements. The connection boundary (also known as the distribution charging connection) will be reduced for reinforcement and removed entirely for demand. Also, distribution connection access rights will be overhauled as Ofgem introduces better non-firm and new time-profiled options, but these will not be available for small users or at the transmission level.
- Reforming residual charges (eg, top-up charges to allow recovery of total allowed revenues and historic costs of network investment) charged by the transmission and distribution networks. Ofgem was concerned the existing framework would lead to inefficient use of the network, adversely impacting consumers. Therefore, the reform will levy a residual charge on final demand users only and create one fixed charge band for domestic users, whereas non-domestic users are subject to a banded approach based on voltage levels. There has been some criticism of Ofgem in deciding to not incentivise lower usage, and thus benefit the environment, by opting for a flat rate.

- Reforming embedded benefits (charging arrangements for smaller generators connected to the distribution system) in line with the above underlying changes. Certain benefits have been entirely removed, such as for the TNUoS demand residual, whereas others have been tweaked in how they are determined, such as for balancing service charge payments. These changes mostly impact small distribution-connected generators below 100MW who benefit from the saved costs embedded benefits create.

In order to implement the changes of the SCR, licence-holders had to raise and make the necessary changes to the DCUSA and, once contemplated, the changes had to be submitted by the DNOs to Ofgem for approval. The changes have been approved and the reforms became effective on 1 April 2023.

A.3 Market design

Capacity market

The UK capacity market and contract for difference regime are well established, with state aid clearances for the capacity market process and the enduring Contract for Difference ("CfD") regime initially awarded in July 2014.

The capacity market is intended to increase the security of electricity supply during peak demand periods, particularly in view of the expected increase in intermittent renewable and inflexible nuclear generation in the future). The capacity market operates concurrently with the electricity market and other National Grid services to ensure a balanced system.
The high-level powers necessary to enable the design and implementation of the capacity market are contained in the EA 2013.

Ofgem is given the power to make and amend the Capacity Market Rules under the Electricity Capacity (Amendment) Regulations 2016.[5] The Secretary of State retains responsibility for certain aspects of the capacity market, such as the amount of capacity to procure, eligibility for capacity auctions and whether or not to hold an auction.

Ordinarily, National Grid holds auctions annually to find the capacity needed to meet demand at the lowest cost to consumers. Generators bid at the lowest price for which they can provide capacity. The capacity market does not encourage or incentivise certain technologies.

The annual "T-4" auctions provide capacity for four years in advance. Payments to the generators are met by the suppliers who pass this cost on to the consumer.

The one-year ahead auctions ("T-1" or "TA" auctions) are intended to support the integration of demand side response ("DSR") and small-scale generation technologies, which may have difficulties in committing capacity four years ahead. See also section F.2 Renewable pre-qualifications.

Emissions performance standard

The Emissions Performance Standard ("EPS") imposes a statutory limit on the amount of CO_2 fossil fuel operated power stations are permitted to produce annually as part of the electricity generation process. Under the EA 2013, EPS applies to new fossil fuel power stations over 50MW (eg, those power stations which received development consent after 18 February 2014), and the limit is set at 450g/kWh (or 450kg/MWh) at a load factor of 85%. This was extended by the Emission Performance Standard Regulations 2015 to old power stations over 50MW which had received planning consent before 18 February 2014 when they replace or add a main boiler. There is a reduction to EPS annual emissions calculated by reference to certification under the Combined Heat and Power Quality Assurance Standard ("CHPQA").

BEIS (now DESNZ), in October 2017, confirmed following consultation its support for closing all unabated coal power stations by 2025. A Government response to consultation published in January 2018 indicated a new emissions intensity limit would be set for coal generating units with a thermal capacity of 300MW thermal from 1 October 2025.

No new policy measures for the EPS are expected as BEIS, following its conducting of a five-year review of the EPS in 2018, announced there would be none.

Consumer redress orders

The underlying gas and electricity legislation to grant formal powers to Ofgem was amended under the EA 2013. The amendments enabled Ofgem to compel licensed (and some unlicensed) gas and electricity businesses to offer redress to consumers, in addition to its existing powers to issue a financial penalty for breach of licence conditions or other relevant requirements.

Ofgem is empowered to issue consumer redress orders, which may provide for: (i) compensation to be paid directly to the consumer; (ii) publication of a written statement outlining the contravention and consequences; and/or (iii) the termination or amendment of the affected consumer's contract. The compensation, together with any financial penalty, is capped at 10% of the relevant company's turnover.

In addition, Ofgem has separate powers to require payments to those not directly affected by a contravention, such as a category of consumers (eg vulnerable consumers) or a charity, trust or organisation.

Levy control framework/control for low carbon levies

The Control for Low Carbon Levies ("Control") restricts the imposition of new low-carbon electricity levies until the burden of low carbon levy costs on electricity bills is seen to be falling. Based on Government forecasts, this Control will rule out any new levy spend until 2025. All existing contracts and commitments will however be respected, including the commitment of up to £557 million (in 2011-2012 prices) for further CfDs confirmed as part of the Clean Growth Strategy.[6]

A.4 Tariff regulation

The framework for setting price controls for gas and electricity transmission and distribution networks is called RIIO (Revenue = Incentives + Innovation + Outputs) and is described as a performance-based model. The model incentivises DNOs to develop a long-term strategy for delivering network services to their customers through allowed revenues control. RIIO sets the outputs that network companies need to achieve and the revenues they are permitted to collect through charges to network users during the control period. The outputs include social, safety and environmental obligations.

The first price controls ("RIIO-1") for electricity transmission were set in 2013 for the period 1 April 2013 to 31 March 2021; the first price control for electricity distribution ran from 1 April 2015 to 31 March 2023.

The second price controls ("RIIO-2") are an investment programme to transform the energy networks and the electricity system operator to deliver emissions-free green energy in GB. Ofgem has decided to set the length of the RIIO-2 period as five years, but with the flexibility to set allowances for some activities over a longer period where companies show evidence of net benefits to consumers. The second price control for electricity distribution runs from 1 April 2023 to 31 March 2028.

Ofgem also decided to set up independent user and consumer engagement groups to challenge companies' business plans, where it provides better value for consumers. It is consulting on the proposed methodology for determining financing costs (including cost of debt and equity) and introducing return adjustment mechanisms.

A default tariff cap for every supply company was introduced by the Domestic Gas and Electricity (Tariff Cap) Act 2018. The cap applies to standard variable tariffs or default tariffs and sets a maximum rate that suppliers can charge default tariff customers per day and a maximum rate per unit of energy. In 2022, Ofgem announced that the default tariff cap will be updated on a quarterly basis rather than every six months to ensure that the cap reflects changes in the cost of supplying energy more quickly. The cap level for charge restrictions period ("cap period") 10a (from 1 April 2023 to 30 June 2023) has been set at £3,280, for a typical default tariff customer, a decrease of 23% on the previous cap period.

A.5 Market entry

Electricity suppliers

In order to successfully enter the market, prospective independent electricity suppliers are encouraged to seek advice from both Ofgem and DESNZ directly as well as separate legal advice in relation to regulatory compliance. Ofgem suggests that the process to become a licensed supplier may take up to 12 months.

To obtain an electricity supply licence, the prospective entrant must apply to Ofgem and pay an application fee. The supply licence allows the licensee to supply electricity to premises (both domestic and non-domestic), and contains information on the licensees' obligations as a supplier, customer interaction, and how to structure and market its products. The Electricity Act allows the Secretary of State to provide exemptions to the requirement for a licence. As well as the supply licence obligations, licensees must comply with industry codes which include technical information relating to accessing industry infrastructure and services.

Alternative market entry routes include purchasing pre-qualified 'off-the-shelf' licences whereby a shelf company acquires the relevant licences before being purchased by the prospective entrant. Licence Lite is a scheme that allows new entrants to enter into a third party licensed supplier agreement ("TPLS") with an existing supplier. The existing supplier undertakes the more complicated areas of supply work (for instance, qualification and industry code compliance) and Ofgem will grant a Licence Lite direction to the new entrant following entry into the TPLS. Ofgem has stated that it intends to put in place new entry requirements with increased information to be provided by prospective suppliers, which is awaited.

Generators

Most companies engaged in the generation of electricity must obtain a generating licence under the Electricity Act, unless an exemption applies. Companies must make an application to Ofgem for a generating licence. Exemptions can be granted individually or to a particular class of persons. Generating plants of 50MW and below can usually benefit from a class exemption, meaning that individual exemption decisions by DESNZ are not required.

Onshore generating stations at or below 50MW and all applications for onshore wind farms require planning permission from the local planning authority pursuant to the Town and Country Planning Act 1990. Onshore generating stations above 50MW, except for onshore wind farms, require development consent from the Secretary of State pursuant to the Planning Act 2008.

For offshore generating stations between 1MW and 100MW, section 36 consent is required from the Marine Management Organisation pursuant to the Electricity Act 1989. Above 100MW, offshore generating stations require development consent from the Secretary of State pursuant to the Planning Act 2008.

Certain regulated activities in English inshore and offshore areas will require a marine licence from the Marine Management Organisation. This includes construction, alteration or improvement works; dredging; deposits; incineration of any substance or object; removal of any substance or object; and scuttling of any vessel or floating container.

With regard to overhead electric lines, consent will be required either under section 37 of the Electricity Act 1989 or development consent under the Planning Act 2008 depending on a large number of factors including, but not limited to, the nominal voltage, length and height of the proposed line.

National Policy Statements published under the Planning Act 2008 set out the Government's policy with regard to the granting of development consents for renewables, fossil fuels, oil and gas supply and storage, electricity networks and nuclear.

The information above relates only to England. From 1 April 2019, the Wales Act 2017 devolved the power to approve certain generating projects to the Welsh Ministers (including the power to grant approval for any type of offshore project of up to and including 350MW in Welsh territorial waters and the Welsh Zone).

A.6 Public service obligations, smart metering and electric vehicles

Public service obligations (PSOs)

The Electricity and Gas (Energy Company Obligation) Order 2018 ("ECO") is the primary legislation governing public service obligations that energy companies must meet while carrying out their services.

Under ECO, any licence holder supplying gas (in accordance with the Gas Act 1986) is considered a participant and must adhere to ECO. ECO requirements mirror those in Article 3 of the EU Electricity and Gas Directives, which include quality of supply, universality of supply, reasonable and fair pricing and environmental considerations.

The ECO seeks to alleviate fuel poverty by obliging larger energy suppliers to provide subsidies for the installation of insulation and heating measures to, and reducing the cost of, heating for low-income, fuel-poor and vulnerable households and communities. The ECO fourth obligation period (ECO4) applies to measures installed from 1 April 2022 and covers a four-year period until 31 March 2026.

Responsibility for fulfilling the savings target obligation is borne by the suppliers, which are each allocated a proportion of the overall target obligation in accordance with their market share during a given sub-phase.

Smart metering

Powers to introduce smart metering for electricity and gas were included in the EA 2008 and extended in the EA 2011. This is intended to provide consumers with more accurate bills and to enable easier grid balancing through the availability of real-time data.

The rollout of smart meters throughout UK households commenced in 2011 and is due to end in 2025.

Ofgem has set binding annual installation targets for all gas and electricity suppliers to roll out smart and advanced meters to their remaining non-smart customers by the end of 2025. It is estimated that by 2030, the introduction of smart meters will have delivered approximately £5.7bn of net benefits to consumers, energy suppliers and networks.

A centralised data communications company ("DCC") will provide communications services to and from gas and electricity smart meters. The Government has awarded the first DCC licence to Smart DCC Ltd, a subsidiary of Capita plc. Stage 1 of the Smart Energy Code ("SEC"), which will until 2025 form a contractually binding agreement between suppliers, network operators, the DCC and other authorised parties. Contracts have also been awarded to Communications Service Providers (Telefonica and Arqiva) and the Data Services Provider (CGI). Domestic suppliers are required to become a DCC User under the SEC under their licence conditions.

The Smart Meters Bill 2018 extended DESNZ (then BEIS) powers to develop and oversee regulations relating to smart metering, to include a special administration regime for the DCC and new powers allowing Ofgem to modify industry codes and documents to deliver market-wide half-hourly settlement using smart metering data. A 4-year smart metering policy framework has allowed the Government to set each energy supplier an individual target on a trajectory to 100% coverage, subject to annual tolerance levels that apply as a percentage of customer base.

The Energy Bill, as introduced into Parliament on 6 July 2022, makes provisions to extend by five years the time for the Government to exercise powers under the EA 2008 in relation to smart meters, to 1 November 2028.

Electric vehicles

The Government's Net Zero Strategy[7], among other things, confirmed the end of sales of new petrol and diesel cars and vans, accelerating the previous 2040 target, with hybrid vehicles to follow by 2035. The Automated and Electric Vehicles Act 2018 provides for the creation of regulations relating to the installation and operation of charging points. This includes provision for the transmission of data relating to charge points (which could affect National Grid and DNOs).

The Department for Transport's Electric Vehicle Infrastructure Strategy[8] included the requirement for all new homes with associated parking to have chargepoints installed at the point of construction. The Government's £950 million Rapid Charging Fund will support the rollout of at least 6,000 high powered chargepoints across motorways and major A-roads by 2035.

Ofgem has indicated that the current regulatory arrangements may need to be adapted to the rise in EV use (for instance, the current legislative framework works on the basis that gas and electricity are supplied to 'premises', and current supply licence obligations may reduce the viability of innovative charging or bundled products). In its report Enabling the transition to electric vehicles: The regulator's priorities for a green[9], fair future, Ofgem confirmed its support for flexible charging to promote charging at times where there is sufficient network capacity and for time of use tariffs for EV users to encourage users to be flexible with their energy demand. Ofgem also noted that industry should focus on minimising overall system costs for consumers (including non-EV users) and therefore network companies should not expect to be remunerated for reinforcement of networks alone where more cost-effective solutions exist.

A.7 Cross-border interconnectors

There are eight interconnectors in operation:

- IFA1 (France, a 2.000MW DC link owned and operated by National Grid and the French Grid Operator, RTE);
- IFA2 (France, a 1,000MW DC link owned and operated by National Grid and RTE);
- Moyle (Ireland, a 500MW link between Scotland and Northern Ireland owned and operated by Mutual Energy);
- BritNed (the Netherlands, a 1,000MW DC link owned and operated by BritNed Development Limited, a joint venture between National Grid and the Dutch system operator, TenneT);
- Nemo Link (Belgium, a 1,000MW link owned by National Grid and the Belgian transmission system operator, Elia);
- North Sea Link (Norway, owned and operated by National Grid and Statnett);
- EWIC (Ireland, a 500MW link owned by EirGrid Interconnector DAO); and
- Eleclink (France, a 1,000MW capacity owned by Getlink (that owns the Channel Tunnel concessionaire Eurotunnel).

Further projects (GridLink (France), FABLink (France/Alderney), Viking (Denmark), NeuConnect (Germany) and Greenlink (Ireland)) will assist by bringing additional capacity to the UK's supply portfolio.

The UK interconnector regime specifically allows for and encourages merchant interconnectors to be developed by private investors. In contrast, other jurisdictions tend to look to incumbent TSOs for development of interconnectors.

The regulatory regime for interconnectors is the 'cap and floor' regime. Pursuant to this regime, developers identify, propose and build interconnectors and the cap and floor mechanism regulates how much they can earn from the project. If revenues exceed the predetermined cap, the excess amounts are returned to National Grid. Conversely, if revenues fall below the predetermined floor level, revenues are topped up by consumers (via TNUoS charges) up to the level of the floor. This developer-led focus aims to balance incentivising investment, through a market-based approach, with both risks and rewards for project developers. The levels of the cap and floor are set based on forecast information and remain fixed for the regime duration. Ofgem operates application windows in which developers submit projects to be considered for the cap and floor regime. The third cap and floor application window closed in January 2023 and all seven electricity interconnector projects that had submitted applications were successful in proceeding to the initial project assessment stage.

B. Oil and gas

B.1 Industry structure

Oil

Nature of the market

Oil from the North Sea enters GB through privately owned pipeline networks that connect to onshore terminals, where the liquids are refined.

The North Sea oil is processed and refined in the UK's six main oil refineries, ie Humber refinery, Lindsey refinery, Grangemouth refinery, Stanlow refinery, Pembroke refinery and Fawley refinery. Products from these refineries are distributed domestically and internationally via freight, pipeline and sea.

Gas

Nature of the market

Gas from the North Sea enters GB through privately owned pipeline networks that connect to onshore terminals where the gases are processed.

All gas entering the high-pressure National Transmission System ("NTS") has to conform to a specification that is set out in the Gas Safety (Management) Regulations 1996. The UK was the first country in the world to fully open its downstream gas market to competition. The downstream gas market is based around the relationship between transporters, shippers and suppliers. Transporters own and operate the pipeline networks (the transportation and distribution systems) and are subject to price control through their licence conditions. Shippers contract with gas transporters for transportation of gas through their pipeline networks. Gas is redelivered to shippers at exit points and sold immediately by shippers to suppliers. Suppliers are the only licensees that have contracts to sell gas to end customers.

The market is fully liberalised in that all gas consumers that are connected to licensed networks are free to choose their own supplier. Customers connected to private unlicensed networks may in many cases also be able to choose their own supplier following the implementation of the Electricity and Gas (Internal Markets) Regulations 2011. The gas market is unbundled pursuant to the full ownership unbundling model in that no licensed gas transporter may hold a gas shipper licence, gas supplier licence or be a gas producer (unless the gas transporter licence contains a condition that gas must not be conveyed to 100,000 or more sets of premises).

Key market players

The North Sea remains a key source of gas for the UK, with around 38% of gas and 75% of oil demand having been sourced from the UK Continental Shelf ("UKCS") in 2021.[10] Gas is also imported through pipelines from Norway, Belgium and the Netherlands as well as liquefied natural gas ("LNG") terminals. In 2021, LNG imports accounted for 17% of the gas supplied to the UK through production and imports, up from 22% in 2020.[11]

On 31 January 2023, National Grid plc announced that it had completed the sale of 60% equity interest in its UK gas transmission and metering business to a consortium comprising Macquarie Asset Management and British Columbia Investment Management Corporation. The distribution networks are operated by Cadent Gas.

The other four distribution networks are owned by Scotia Gas Networks Limited (owned by a consortium of Apple Newco Limited (indirectly wholly-owned by Ontario Teachers' Pension Plan Board), UK Gas Distribution 2 Limited (indirectly owned by Brookfield Super-Core Infrastructure Partners), and Speyside Bidco Limited (wholly-owned by Global Infrastructure Partners)), Northern Gas Networks Limited (owned by a consortium of CK Infrastructure Holdings Limited, Power Asset Holdings Limited and Australian pension fund the SAS Trustee Corporation)[12] and Wales & West Utilities Limited.[13]

British Gas (owned by Centrica) dominates the GB gas market in terms of supply to domestic customers. Other significant gas suppliers include E.ON, EDF Energy, Scottish Power and Ovo Energy, all of which also participate in the electricity supply market.[14] Offshore, the position is more complex with a number of companies holding substantial portfolios of gas reserves in the North Sea. Key producers in terms of gas include BP, Shell, and Centrica.

In Northern Ireland, there are four gas transmission pipelines, respectively owned by Premier Transmission Limited, Belfast Gas Transmission Limited and BGE Northern Ireland.[15] There are three gas distribution companies: Firmus Energy (Distribution) Ltd, SGN Natural Gas Limited and Phoenix Natural Gas Limited. There are several gas suppliers, including SSE Airtricity Gas Supply (NI) Limited, Firmus Energy (Supply) Limited, Flogas Enterprise Solutions Limited and Electric Ireland.[16]

Regulatory authorities

Ofgem is responsible for regulating the downstream gas market, including the monopoly gas transmission and distribution networks. Ofgem is also responsible for the enforcement of the third-party access regime applicable to downstream gas infrastructure.

The North Sea Transition Authority ("NSTA") is the regulatory authority in the UK responsible for petroleum licensing and regulating the upstream oil and gas sector including: oil and gas licensing; oil and gas exploration and production; oil and gas fields and wells; oil and gas infrastructure; and carbon storage licensing.

The NSTA was known as the Oil and Gas Authority ("OGA") until March 2022. The new name embraces the authority's evolving role in the energy transition, including in the monitoring of greenhouse gas ("GHG") emissions, stewarding domestic production, assessing a net zero test for new developments and as the carbon storage licensing and permitting authority.[17]

NSTA offshore licensing rounds

The NSTA holds offshore petroleum licensing rounds, inviting applications from companies and making awards to those bids that promise to ensure economic recovery of the UK's oil and gas resources, whilst supporting the drive to net zero by 2050.[18]

In September 2022, the UK Government confirmed its support for a new licensing round, expected to lead to over 100 new licences.[19] This round officially opened on 7 October 2022 and applications were accepted until 12 January 2023.[20]

To encourage production as quickly as possible, the NSTA has identified four priority cluster areas in the Southern North Sea which are close to infrastructure, have known hydrocarbons and have the potential to be developed quickly and will seek to license those areas ahead of others.[21]

Best available techniques

The Department for Environment, Food and Rural Affairs ("DEFR") published a policy paper on 30 August 2022 in respect of establishing the best available techniques ("BAT") for the UK.[22] The policy paper outlines that the future development of the UK BAT conclusions ("BATC") will be led by:

- the UK Government;
- the Scottish Government;
- the Welsh Government; and
- the Northern Ireland Department for Agriculture, Environment and Rural Affairs.

The UK BATC will be determined through an evidence-based approach with industry, regulators and non-governmental organisations.[23]

The UK BAT system is expected to take between one to three years to create a set of BATCs, depending on the complexity of the industrial sector.

A government response and summary of responses was also published by DEFR and the devolved governments, in response to a consultation in January 2021 seeking views on a new process for developing new UK BAT to manage industrial emissions.[24] The government response confirms that a BAT common framework is being developed and has been provisionally agreed between the administrations, subject to parliamentary scrutiny.[25]

Legal framework

The key legislative provisions are set out in the Gas Act 1986 as amended by the Gas Act 1995, the Utilities Act 2000 and the EA 2004.

The EA 2008 contains the regulatory regime for offshore gas storage and unloading (eg, of LNG), as well as for the storage of CO_2. The EA 2011 facilitates the development of carbon capture and storage ("CCS") demonstration projects by amending the EA 2008 to provide the Secretary of State with a discretionary power to designate an offshore installation or pipeline which, when used for a demonstration project, removes the possibility that the organisation that had previously used the facilities only for petroleum production activities can be made liable for its decommissioning. The EA 2011 also amends the Pipelines Act 1962 to allow the compulsory acquisition of rights to transport CO_2 from the owners of the land through which pipelines pass.

Under section 5 of the Gas Act 1986 it is an offence to carry out any of the activities of transporting gas via pipelines, shipping or supplying gas or operating a gas interconnector without the benefit of a licence granted by Ofgem or an exemption. Ofgem grants licences, subject to certain conditions, and oversees and enforces compliance with licence conditions. Ofgem's enforcement powers extend to revoking licences and issuing enforcement orders and financial penalties. Ofgem can also make consumer redress orders, which require a licence holder to take remedial action where it has caused consumers loss, damage or inconvenience. Ofgem's enforcement powers also extend to unlicensed activities.[26]

Petroleum Act

The primary piece of legislation governing the exploration and production of crude oil, gas, and shale gas in the UK is the Petroleum Act 1998 (as amended) (the "Petroleum Act") which is supplemented by the Energy Act 2016 ("EA 2016"), the Infrastructure Act 2015 and various environmental and health and safety legislation.

The Petroleum Act regulates all oil and gas exploration and production in the UK, with the exception of onshore in Northern Ireland.[27] The Petroleum Act vests all rights to the UK's petroleum resources in the Crown, however the Act gives the Government the right to license the exclusive rights to search and explore petroleum sites. The Petroleum Act thus provides a mechanism by which the NSTA (as well as the Welsh and Scottish Ministers for onshore oil and gas in Wales and Scotland, respectively) grants licences to confer exclusive rights to 'search and bore for and get' petroleum. Those granted a licence are given the authority to conduct exploration and development within a particular geographic area.

Infrastructure Act

The Infrastructure Act 2015 modernises the framework for accessing underground resources and makes it more straightforward for companies to drill and search for oil, shale gas and geothermal energy. One of the ways that the Infrastructure Act 2015 does this is by defining the deep-level land as being at least 300 metres below the surface, by which licence holders are permitted to explore without seeking permission of the regulating authority (subject to rights of use of land).[28]

Energy Acts

The key elements of the EA 2011 are primarily the powers it provides the NSTA in relation to determining disputes by making appropriate binding determinations as to the terms and conditions for which parties can access upstream infrastructure, such as offshore pipelines, processing facilities, and onshore terminals.

The main feature of the EA 2016 is that it formally established the OGA (now the NSTA) as an independent body overseeing and regulating the oil and gas sector. The EA 2016 also amended the Petroleum Act to give the NSTA powers to oversee decommissioning activities by requiring an applicant of an abandonment programme to consult the NSTA. The Act also requires the Secretary of State to take into consideration the opinion of the NSTA on such consultations prior to approving an abandonment programme.

Downstream: Energy Act and Oil Stocking Order

Two primary pieces of legislation regulate the downstream sector. The first is the Energy Act 1976, which gives the Government wide powers in terms of regulating or prohibiting the supply, production, acquisition and/or use of petroleum products. This is primarily in consideration of national emergency circumstances. The second piece of legislation is the Oil Stocking Order 2012, which contains more detailed, mostly procedural, provisions concerning UK stockholding obligations and emergency measures.

Implementation of EU gas directives

Following Brexit, the EU Gas Regulation became retained EU law under the European Union (Withdrawal) Act 2018 and was amended so that it could operate effectively after the end of the UK-EU transition period.

In practice, this results in two versions of the legislation existing concurrently:

- the original EU version (which is applicable to the remaining 27 EU member states) as amended by any EU legislation taking effect after 1 January 2021; and
- the retained version of the EU Gas Regulation (the "UK Gas Regulation"), which is applicable in the UK and is based on the EU Gas Regulation as it stood on 31 December 2020 but incorporates changes made during the onshoring process to adapt the legislation to the UK context.[29]

The UK Gas Regulation is primarily concerned with the downstream gas industry. Whilst the UK Gas Regulation includes obligations for Ofgem, gas transmission system operators, other gas transporters, and gas interconnector operators, it is important to note that the majority of these obligations have already been implemented within the domestic framework of legislation, licences and industry codes in GB due to the prior implementation of the EU Gas Regulation.

The amendments introduced requirements for the legal and operational unbundling of gas storage system operators to ensure their independence and the enhanced requirement to grant third party access to storage facilities that are technically and/or economically necessary for providing efficient access to the system. The amendments also enable Ofgem to enforce compliance with new obligations (including obligations relating to transparency and the publication of daily information about gas flows and capacity) imposed directly on operators of gas storage and LNG facilities.

The legislative requirements for operators of gas storage, including LNG storage, facilities include;

- rules requiring the legal and functional separation of gas storage operators from any parent and affiliate undertakings involved in gas production or storage (unless they benefit from a minor facility exemption);
- a requirement for Ofgem to publish criteria regarding the availability of the exemption from the requirement to provide negotiated third party access for minor facilities, and to publish details of facilities to which negotiated third party access is available; and
- a requirement for gas storage operators and owners of gas processing facilities to consult system users when developing commercial conditions for the provision of ancillary services.

Operators of gas storage and LNG facilities are subject to application process requirements for third party access exemptions for new or expanded infrastructure, including requirements to comply with capacity allocation rules. They are also affected by confidentiality requirements restricting the use and disclosure of information by operators of gas storage and LNG facilities.

Ofgem has been given enforcement powers by making the obligations relating to gas storage and LNG facilities into 'relevant requirements' for the purposes of the Gas Act 1986 (allowing Ofgem to issue enforcement orders and impose financial penalties of up to 10% of annual turnover). Obligations on owners of gas processing facilities relating to accessing or operating a gas transporter's pipeline, an interconnector, a gas storage facility or an LNG import facility are also enforceable as 'relevant requirements'.

B.2 Third party access to gas transportation networks

The contract for the use of the transportation systems is referred to as a Network Code. Each licensed transporter is obliged by its licence to have a Network Code which incorporates the Uniform Network Code ("UNC"), that contains the principal terms for access to, and use of, the pipeline network and can only be changed with Ofgem's approval, and the transporter's own network specific terms. In order to be a party to a Network Code, a new entrant must first acquire a shipper's licence and then sign the relevant framework agreement acceding to the terms of the code. Each code is a multi-party contract between the relevant transporter and all shippers using its transportation system. Access to the networks is therefore available on a non-discriminatory basis.

Gas transportation prices are regulated by Ofgem through a licence condition restricting revenue by overall or average prices. Ofgem also controls charges in relation to system operation, gas storage and metering both at the NTS as well as the distribution networks level. Gas transporter licences require licensees to prepare a charging methodology which is reflective of cost and which encourages competition. As with electricity transmission and distribution, the regulatory framework for gas transportation and distribution uses the RIIO (Revenue = Incentives + Innovation + Outputs) formula.

Shippers pay transporters a number of charges for using their networks, with the main charges relating to system capacity, volumes transported (commodity charges) and balancing charges. Each shipper is required to hold a volume of entry capacity to put gas on to the relevant network. Entry capacity is allocated via auctions and capacity can be purchased on a day-ahead, rolling month-ahead, annually auctioned monthly, or annually auctioned quarterly basis (for capacity that will be available from two to 16 years after the auction date). There is also a secondary capacity market between shippers.

The commodity charges levied by each transporter relate to the costs of transporting gas to NTS exit points and within local distribution networks. Balancing charges relate to charges levied where a shipper's inputs and offtakes are not in balance. Where this is the case, the shipper will have been deemed to have entered into a transaction with the transporter for the sale or purchase of gas as applicable. The transporter will calculate a buy price or sell price, depending on the level of imbalances and the cost to the transporter of supplying the relevant gas themselves. The transporters are incentivised through their price control mechanism to minimise these imbalance charges. Where the volumes of gas put onto the system or taken off the system differ from the shipper's nominations, the shipper will also have to pay scheduling charges.

All title to gas in the relevant network is held by the transporter. Title transfers from the shipper to the transporter at the entry point and is re-transferred to the shipper at the exit point. The transporter's liability for off-specification gas is strictly limited and calculated by reference to the volume of off-specification gas actually off-taken by a shipper. All gas that is put onto the NTS must meet the specification set out in the relevant regulations.

RIIO-2

The second RIIO phase, ie RIIO-2, covers the five-year period from 1 April 2021 to 31 March 2026. RIIO-2 is designed with the same objective as RIIO-1, ie to encourage network companies to provide safe and reliable services, innovate to reduce network costs for consumers and play a bigger role in delivering a low carbon economy with wider environmental considerations in mind.

Interconnectors

The interconnector licence provides a 'switching' mechanism for conditions that introduce third party access obligations. This enables Ofgem to 'switch on' or 'switch off' specific conditions in relation to a particular licence. In order to suspend the operation of (ie switch off) a relevant condition, Ofgem has to be satisfied that all of the criteria for derogations and/or exemptions from the third party access regime under European law have been satisfied. Where such conditions cease to be satisfied, a relevant condition may be switched back on. The overriding objective behind the regulations is that licensees are to make available the maximum capacity at all entry and exit points. This mechanism remains in place following the introduction of the Electricity and Gas (Internal Markets) Regulations 2011, but the regulations amend the standard conditions of the licence to reflect the requirements of the Third Energy Package in relation to new infrastructure exemptions from third party access. The changes apply to any new applications for an exemption for a new interconnector, or modifications to an existing interconnector. Exemptions continue to be granted by Ofgem but the Agency for the Cooperation of Energy Regulators and the European Commission (the "Commission") will have a greater role in the final decision.

Ofgem needs to approve the capacity allocation mechanism to be used when allocating and managing capacity in the interconnector before granting the exemption. Licensees that were exempt from third party access obligations for the purposes of the Second Energy Package can continue to operate under the terms of that exemption order, and will not be obliged to comply with the ownership unbundling requirements imposed by the regulations. As well as requiring gas transporters to be certified as independent by Ofgem, the regulations impose the same requirement on the operators of gas interconnectors. Prior to granting certification, Ofgem must be satisfied that the ownership unbundling tests have been satisfied, or that a derogation or exemption is available.
Full unbundling, the independent system operator model, the 'unbundling derogation for arrangements providing greater independence than the independent transmission operator (''ITO'') model', and the ITO model are available for gas interconnectors.

B.3 LNG terminals and gas storage facilities

The UK has a number of LNG terminals, located in England and Wales. The South Hook and Dragon LNG terminals (owned by Qatar Petroleum International. ExxonMobil and Total; and Shell and Petronas respectively) are located at Milford Haven in South Wales. On the east coast, the Isle of Grain terminal (National Grid) is located in Kent in the south of England, the largest terminal in Europe with 1 million cm of tank space, and the Gasport floating LNG terminal (Excelerate Energy) is located in Middlesbrough, Teesside. in the north of England.

B.4 Tariff regulation

A new bill to cap poor value energy tariffs was passed in Parliament on 18 July 2018, under which Ofgem are required to cap standard variable and default energy tariffs. The cap came into force at the end of 2018 and remained in place until 2020; Ofgem will recommend whether the cap should remain on an annual basis up to 2023. In 2022, Ofgem announced that it would review the level of the cap at least every three months instead of every six months while it is in place.

B.5 Market entry

Gas suppliers, shippers, transporters and interconnector operators require a licence from Ofgem, unless an exemption applies. Each licence sets out a number of requirements for market accession, including requirements for transporters and shippers regarding maintaining and becoming a party to the relevant Network Code. A separate licensing regime applies for offshore gas storage activities. Such offshore activities also require a lease or licence from the Crown Estates.

B.6 Public service obligations and smart metering

Public service obligations (PSOs)

The ECO is the primary legislation governing PSOs that energy companies must meet while carrying out their services. For more on the ECO see section A.6.

Smart metering

Ofgem has set binding annual installation targets for all gas and electricity suppliers to roll out smart and advanced meters to their remaining non-smart customers by the end of 2025.[30] For more on smart metering see section A.6.

B.7 Cross-border interconnectors

The UK has the following cross-border gas interconnectors:

- the Interconnector UK linking the Bacton terminal to the gas hub at Zeebrugge in Belgium;
- the Balgzand and Bacton Line ("BBL") linking Bacton with Balgzand in the Netherlands, which has been granted a third party access exemption; and
- the 'Moffat' interconnector, which consists of two pipelines and which runs between Moffat in Scotland and the Republic of Ireland.

The Langeled Pipeline links the Easington Gas terminal in England to the Nyhamna terminal in Norway but is not, for legal purposes, an interconnector. There is also a gas interconnector between Twynholm in Scotland and Ballylumford in Northern Ireland (the Scotland to Northern Ireland Pipeline) ("SNIP"), which is owned and operated by Premier Transmission Limited.

C. Energy trading

C.1 Electricity trading

No separate licence is currently required for wholesale electricity trading, which does not involve supply to customers. Most trading is physical trading, with a small amount of financial trading. Some participants will require Financial Conduct Authority ("FCA") approval for their activities.

All licensed electricity companies in GB must sign up to the Balancing and Settlement Code ("BSC"), which contains the rules and governance arrangements that facilitate wholesale electricity trading and electricity balancing in GB. Other parties, such as investment banks, may sign the BSC and participate in the market as non-physical traders. All generators and suppliers have energy accounts with the market operator, Elexon Limited ("Elexon"). Electricity 'trades' for contracted generation and consumption are notified to Elexon and reflected in these accounts, which are also credited and debited with any physical metered volumes flowing onto and off the electricity network as energy is generated and consumed. Notifications only cover volumes traded and the dates when the trade is effective. Elexon is a subsidiary of National Grid and is ring-fenced from National Grid's other activities.

The standard form bilateral trading contract, ie the Grid Trade Master Agreement ("GTMA"), does not have a delivery point and does not claim to transfer title to volumes of electricity. Trades may also be made under an International Swaps and Derivatives ("ISDA") Master Agreement with an electricity schedule to fit with the BSC notification processes, or bespoke power purchase agreements can be used. In practice, if a generator fails to deliver the relevant volume of power to the grid a supplier can offtake the traded volume without incurring any imbalance charges, and the generator will incur the imbalance charges. Imbalances are settled centrally via BSC Central Systems, a closed system whereby all surplus cash and any deficits are distributed and charged equally to all parties, respectively. If notifications are not made, or are made incorrectly, then the parties will incur imbalance charges as their energy accounts will not match their physical position for a given settlement period as per the metered volumes recorded. The notification procedure is a single notification process; one of the parties to a trade will agree to make the notification, or the parties have to find a third party to perform this role. Notifications can be adjusted at any time prior to gate closure (see below) and mistakes can usually be identified and mitigated before any imbalance costs are incurred.

Each generator and supplier must also notify its expected physical position to National Grid under the terms of the Grid Code, and corresponding provisions of the BSC. The party designated as the lead party will usually be responsible for making a notification known as a physical notification, which covers the expected level of generation and consumption for a particular settlement period. To assist with the balancing, trading and financial settlement process, each day is currently divided into 48 settlement periods of 30 minutes each. BSC parties may only notify wholesale trades to Elexon up to one hour before the start of the settlement period to which a trade relates, ie gate closure. At this point the physical notification becomes a final physical notification and parties must adhere to these. During the one-hour window between gate closure and the start of a settlement period, a secondary market operates to balance the system, ie the balancing mechanism. During this period, National Grid will consider the final physical notifications it has received and the steps that need to be taken to balance the system in real time.

Each physical participant is required to submit bids to the balancing mechanism to either increase or decrease the volumes of electricity that they deliver or offtake from the system. Depending on the operational position, National Grid will accept the most appropriate bids or offers. The price of the bids and offers accepted is used as part of the calculation of the relevant imbalance prices. For each settlement period Elexon establishes the extent to which a party is in imbalance by comparing the volume of power delivered or offtaken from the system by a party against that party's energy account. If the physical position does not match the notified contractual position, that party is out of balance. If a generator delivers less power than it has sold or a supplier takes more power than it has purchased, that party is 'short'. If a party is short, then to the extent of the shortfall, Elexon will charge that party the 'system buy price'. If a generator provides too much power, or a supplier offtakes too little power (or, to use industry terminology, they are 'long'), then it will be paid the 'system sell price'. Each settlement period has a single cash-out (system buy/sell) price.[31]

C.2 Gas trading

Gas trading requires the trader (or its agent) to hold a gas shipper's licence in order to notify trades for the physical conveyance of gas. There is also a small amount of financial trading permitted of gas as a commodity, and FCA approval may be required for some participants. This reflects how Ofgem views trading to be a separate activity from shipping and creates the role of Trade User in the Uniform Network Code. Many parties however continue to hold a gas shipper's licence. Gas trading in the UK is subject to UK REMIT (as retained EU law), EIR and MiFIR for the purposes of transparency and regulation of financial instruments.

Gas trading occurs at a number of points in or between pipeline systems. Gas is predominantly traded at the National Balancing Point ("NBP"). NBP is a notional point, which is used for gas trading and calculating transportation charges relating to traded gas within the NTS. Shippers trade gas between themselves within the NTS at the NBP, as it is the place where all gas entering or leaving the NTS is assumed to originate.

Beach contracts are usually entered into on the terms of the updated Beach 2015 contract, which is a physical contract with provisions relating to title, quality and pressure. The 'Beach' is the point where offshore gas comes ashore and is about to be put onto the NTS. An imbalance regime exists relating to failure to deliver the relevant quantities of gas and for any shortfalls the seller pays the buyer the higher of the 'system average price' or 'system marginal buy price'. These are two of the prices NGG uses for the balancing regime under its Network Code.

Trades between shippers, and exchange-based trading generally, are normally on the terms of the NBP 2015, or under an ISDA Master Agreement, with a specific gas annex.

Neither the NBP nor the ISDA contracts are physical contracts in the sense that they do not provide for the transfer of title to physical volumes of gas, as title to gas within the NTS rests with NGG. Instead, each party makes nominations to NGG which adjust the volumes of gas that the relevant party recognises as having been delivered to or taken off the NTS by the relevant shipper.

Shippers nominate the volumes of gas that they will put on to the NTS on a day-ahead basis. Shippers can adjust their positions by making re-nominations or submitting NBP trades, at any time up to 3.59am on each gas day. The gas day runs from 5am on each calendar day to 5am on the following calendar day, a change reflected in the NBP 2015 terms as part of the EU harmonisation at the time.

A dual notification system is operated so both parties must make the notification and if the notifications do not match NGG will reject the relevant trade. The NBP trading system has its own credit cover provisions which are separate from the credit cover that shippers provide in relation to their transportation charges. If one party makes an error in its notification, it will be liable to pay deemed imbalance charges to the other party, which are the imbalance charges that the other party would have incurred if the relevant trade were the only transaction that party had entered into on that day.

The imbalance prices mentioned above are calculated by NGG on a daily basis and relate to the prices that NGG pays, or is paid in the market for the balancing actions it takes. NGG can trade gas via an exchange (it is the only gas transporter that can trade gas in this way) and NGG's licence incentivises it to minimise imbalance charges.

Gas transporters trade gas between themselves under the terms of the 'offtake arrangements document', which is part of the UNC.

Shippers sell gas to suppliers immediately after exit points from pipeline systems, although typically most suppliers also hold gas shipping licences and operate as one integrated entity.

D. Nuclear energy

Nuclear energy

There are currently 9 nuclear reactors operating on 5 sites in Britain, which provided 14.8% of the UK's electricity in 2021. All of Britain's operating nuclear power stations (including Sizewell B – Britain's newest nuclear power station which began operation in 1996) are owned and operated by EDF Energy Nuclear Generation Limited (formerly British Energy Generation Limited), a part of EDF Energy, one of the UK's largest electricity generators of which Centrica also owns a 20% share.

Sizewell B is a pressurised water reactor and the rest of EDF Energy's reactors are advanced gas cooled reactors. Dungeness B situated near Romney Marsh, Kent; Hunterston B in North Ayrshire, Scotland, and Hinkley Point B located near Bridgwater, Somerset all ceased generation in June 2021, January 2022 and August 2022, respectively. The majority of the UK's nuclear power fleet is expected to cease operation by 2030, with only Sizewell B estimated to continue generating electricity until 2035.

Nuclear decommissioning

The Magnox stations are owned by the Nuclear Decommissioning Authority ("NDA"), which is a non-departmental government body established in April 2005 under the EA 2004 to oversee clean-up, decommissioning and operation (pending clean-up and decommissioning) of certain civil nuclear sites in Britain. In particular, designated sites at Sellafield. Calder Hall, the Low Level Waste Repository near Drigg, Capenhurst, Dounreay, Windscale. Harwell, Winfrith. Springfields, Chapelcross. Bradwell. Berkeley, Wylfa, Trawsfynydd, Oldbury, Sizewell A, Hunterston A. Dungeness A and Hinkley Point A. The NDA put in place a series of management and operations contracts (Site Licence Company Agreements) to manage and decommission the sites and has run competitions for the award of these contracts in order to open up the nuclear clean-up and decommissioning industry to competition.

The NDA's operational structure is based on a subsidiary operating model, with Sellafield ltd., Magnox ltd., Dounreay Site Restoration ltd., Nuclear Waste Services and Nuclear Transport Solutions being its current subsidiaries. The NDA envisages that this group will grow following the upcoming decommissioning of nuclear plants in the UK.

EDF are, under an agreement with the Government, responsible for defueling all 7 advanced gas cooler nuclear power stations, starting with Hunterston B and Hinkley Point B, which have already ceased operation. Once the reactors are emptied of fuel, they will be transferred to the NDA on a rolling basis, whose subsidiary Magnox will complete the rest of the decommissioning process.

The NDA is also responsible for planning and implementing a geological disposal facility ("GDF") for the long-term disposal of high level radioactive waste. To facilitate this, in 2007 the NDA acquired the shares in UK Nirex Limited, the organisation that was responsible for carrying out research into long-term solutions for safe and environmentally sound disposal of radioactive waste, and the Nirex staff were integrated into the Radioactive Waste Management Directorate of the NDA. Community partnerships and working groups around the UK are exploring whether a geological disposal facility ("GDF") could be built in their area. These disposal facilities involve isolating radioactive waste deep underground in rock that is suitable to ensure no harmful quantities of radioactivity reach the surface. Construction of such facilities will begin only when a suitable site is identified, and all necessary consents and permits are obtained. The relevant community must also indicate its willingness to host the facility. It is estimated that, based on latest planning assumptions, that a GDF could be ready to receive intermediate level waste between 2050-2060.

Nuclear new build

In light of the expected closure of the UK's existing civil nuclear reactors, and amid increasing concern in relation to climate change, decreasing supplies of fossil fuels, security of supply and increasing demand, the private sector in the UK has the option of constructing new nuclear power stations. Further to this, NNB Generation Company Limited ("NNB"), a joint venture between EDF and CGN, a Chinese state-owned nuclear operator, is constructing a nuclear power station in southwest England. NNB has signed a CfD for Hinkley Point C and the project is under construction with commissioning planned for June 2027.

On 27 January 2022 and in support of its Ten Point Plan for a Green Industrial Revolution published in November 2020, the Government announced an investment of £100 million to support the continued development of the Sizewell C nuclear power plant in Suffolk. The announcement follows the Government's decision in November 2021 to invest £210 million in the development of the world's first small modular reactors. The Sizewell C nuclear power plant is slated to produce 3.2 GW of electricity and support up to 10,000 jobs across the UK. The £100 million investment takes the form of an option fee over certain rights over the land of the Sizewell C site as well as shares in the Sizewell C company. If Sizewell C reaches a final investment decision (expected in 2023), the Government will receive a reimbursement of the option fee with a financing return, either in the form of cash or equity in the project.

Development of the Bradwell B project in Essex by a joint venture of CGN and EDF is at an early stage, with investigative site works ongoing and GDA approval being sought for the UK HPR1000 technology. A stage one consultation ran between 4 March 2020 and 1 July 2020 in accordance with the obligation on developers within the Planning Act 2008 to consult widely with the surrounding community and other organisations such as councils, businesses and community groups.

One regulatory change that was introduced to facilitate nuclear new build in the UK is the Generic Design Assessment Process ("GDA"). The GDA enables regulators to consider the safety, security and environmental impact of each of the industry's preferred reactor designs, at the request of a reactor vendor, in advance of any consideration of the impact of each reactor at a particular site when the prospective operator applies for a nuclear site licence.

On 7 April 2022, the Government announced its British energy security strategy which would involve setting up a £120 million Future Nuclear Enabling Fund supported by a new government body, the Great British Nuclear Vehicle, tasked with assisting new build nuclear projects through every stage of the development process.

Legislative framework

The key legislation for the nuclear industry is the Nuclear Installations Act 1965 ("NI Act"), the Nuclear Installations Regulations 1971 ("NIR1971"), the Environmental Permitting (England and Wales) Regulations 2010 ("EPR 2010"), the EA 2004, the EA 2008, the EA 2011 (in particular, in relation to the funding of waste management and decommissioning costs associated with new nuclear build), EA 2013, the Nuclear Energy (Financing) Act 2022 and several pieces of legislation governing the transport of radioactive materials.

The NI Act sets out the licensing, liability and insurance regime in respect of the installation and operation of nuclear reactors (except any reactor comprised in a means of transport) and nuclear installations. The NIR 1971 prescribes those installations that require a licence to be granted under the NI Act (which include not only large-scale commercial nuclear reactors, but also research reactors, nuclear fuel manufacturing and isotope production facilities, fuel reprocessing and the storage of radioactive matter in bulk).

Under the NI Act, a licence is required for the installation and operation of a nuclear reactor/installation. Nuclear site licences may only be granted to a body corporate and are not transferable. The EPR 2010 subsumed the Radioactive Substances Act 1993 and sets out the regime for the authorisation of the disposal of radioactive waste. The EA 2008 imposes duties on energy companies wishing to construct new nuclear reactors in the UK to adopt a programme for the funding of the costs of waste management and decommissioning for the new plant, where such programme is pre-approved and overseen by the Secretary of State. The EA 2011 allows the Secretary of State contractually to restrict his powers to unilaterally modify such a programme after its approval. Amendments have been made to the decommissioning provisions, including section 66 of the EA 2008, which allows the Government to be paid directly for providing a waste repository, and section 46 of the EA 2008, which provides greater certainty to investors in new nuclear power with regard to how the funded decommissioning powers will operate.

The EA 2013 Act gives power to the Office for Nuclear Regulation ("ONR") to grant site licences to the operators of those nuclear reactors and installations prescribed under the NI R 1971. The ONR is the regulator responsible for licensing nuclear installations. Under the NI Act, the ONR is required to attach such conditions to a nuclear licence as it thinks fit in the interests of safety. Currently, the ONR imposes a set of 36 standard conditions, each of which define areas of nuclear safety to which a licensee should pay attention in order to ensure safe operation of the site (eg there are conditions in respect of what nuclear matter may be brought onto the site, training of staff, control of organisational change and the requirement to establish a nuclear safety committee). Some conditions impose duties on the licensee, while others require the licensee to devise and implement 'adequate arrangements' (eg to control any change in its organisational structure). Each licence may also include such additional site-specific conditions as the ONR thinks fit, depending on its assessment of the site concerned. The ONR may also, at any time, attach conditions relating to the handling treatment and disposal of nuclear matter.

A nuclear site licence is non-prescriptive and sets goals for the licensee, generally leaving the method of implementation to the licensee. The licence conditions are flexible as the ONR may, at any time, amend or revoke any existing licence condition.

A licence can be revoked by the ONR or surrendered by the licensee at any time (though see below as to the period of responsibility). The ONR must consult the Environment Agency before revoking a licence. The Environment Agency and the Scottish Environment Protection Agency are responsible for safeguarding the environment.

The NI Act enacts the provisions of the Paris Convention on Third Party Liability in the Field of Nuclear Energy and the Brussels Convention Supplementary to the Paris Convention to both of which the UK is a contracting state. These Conventions set out the arrangements for compensation for nuclear damage arising from nuclear incidents at civil nuclear sites and during the transportation of nuclear matter between operators in different territories. The Nuclear Installations (Liability for Damage) Order 2016/562 ("Order") amends the NI Act to reflect changes to the Paris and Brussels Conventions brought by the 2004 Protocols. The amendments include increased liability caps and limitation periods and expanded scope of claims and possible claimants. In light of this, the 2004 Protocols have amended the definition of nuclear installations under the Paris Convention to include nuclear waste disposal facilities and these are now covered by the liability regime.

Under the Paris and Brussels Conventions, the right to compensation for damage caused by a nuclear incident may be exercised only against the operator liable for the damage, this is unless national law gives a direct right of action against the insurer or other financial guarantor. Under the Conventions, the operator has a right of recourse against third parties to the extent expressly provided for by contract or, if the damage caused results from an intent to cause damage, against the individual acting or omitting to act with such intent.

The NI Act places a duty on the licensee to secure that no occurrence involving nuclear matter and no emission of ionising radiation causes injury to any persons or damage to property (other than its own property). In addition, the Order introduced the following new categories of damage that can be compensated for: (i) environmental reinstatement costs; (ii) loss of income due to nuclear damage restricting economic interests in use or enjoyment of the environment; (iii) costs of preventative measures following a nuclear incident or where there is a grave and imminent threat of such incident taking place; and (iv) personal injury and property damage caused by taking preventative measures.

The 2004 Protocols have also extended the geographical scope of the Paris Convention to allow compensation for damage suffered in countries that are not signatories of the Paris Convention and that: i) did not have nuclear installations in their territory at the time of the nuclear incident; and ii) have equivalent reciprocal nuclear liability regimes.

Following the 2004 Protocols, the Order makes provisions to allow the government of another country to bring representative proceedings in the UK on behalf of its people (nationals and persons resident or domiciled in that country). Equally, the Secretary of State is given power to represent UK nationals and people domiciled or resident in the UK in claims under the Paris Convention in Paris Convention signatory countries and territories. Generally, a licensee is responsible under its licence for the 'period of responsibility', which is the period running from the date of the grant of the licence and ending with the earlier of either (a) the date when the ONR notifies the licensee that there is no longer any danger from ionising radiation on the site; or (b) the date when a new licence has been granted in respect of that site. There are circumstances under the NI Act in which a former licensee could incur liability beyond its period of responsibility.

Following the entry into force of the Order, licensee's and disposal site operator's duties to compensate are limited under the NI Act to the equivalent of €700 million per occurrence immediately upon entry into force of the Order (1 January 2022) and a further €100 million each year thereafter up to a maximum of €1.2bn. Lower national liability caps may be set for certain categories of sites as follow: (i) the equivalent to €70 million for low risk sites; (ii) the equivalent to €80 million for low risk transport sites; (iii) the equivalent to €160 million for intermediate risk sites.

Where the applicable liability limit above is exhausted, liability is passed on to the UK Government up to a maximum of €1.5bn for damage incurred in a country that is a party to the Brussels Convention or €700 million otherwise. Claims on such public funds are to be made by bringing proceedings against the appropriate authority.

Claim for personal injury must be made within 30 years of the date of the relevant occurrence and 10 years for all other claims. This is an absolute time bar for all claims and overrides all other statutory limitation periods.

The NI Act sets out the insurance/indemnity obligations imposed on the holders of site licences and operators of disposal sites. They must hold the appropriate level of insurance or an indemnity to the appropriate level (as may be determined by the Secretary of State, with the consent of the Treasury), which may be any amount up to the current limit on liability.

The insurance cover required to be held under the NI Act relates to claims in the aggregate (whereas the limit on liability is per occurrence) and could, therefore, be exhausted if there were a number of occurrences in the same period of responsibility. In this case, if insurance cover were to be exhausted, the Secretary of State may direct that a new cover period begins from a specified date.

In addition, the Energy Bill ("Bill") which is being considered by Parliament at the time of printing (Summer 2023) makes provisions to enable UK's accession to the Convention on Supplementary Compensation for Nuclear Damage ("CSC"). The CSC is a freestanding independent instrument designed to provide compensation for damages in the case of a nuclear incident and may be used as a supplementary to the Paris Convention and the Vienna Convention on Civil Liability for Nuclear Damage 1963. A key advantage of the CSC is that contracting parties agree that jurisdiction over claims relating to nuclear damage or injury can only be in the courts of the country where the incident occurred. It is open to all states regardless of whether they have nuclear installations, so long as the state has national legislation consistent with the uniform rules on civil liability laid down in the Annex to the CSC.

The Bill would amend the NI Act so as to implement the requirements of the CSC. Key amendments are those to s.16, including new subsections which set out the liability limits for claims relating to the CSC, where the amount payable by:

- a person would be up to the equivalent in sterling of 300 million special drawing rights apart from interest or costs (this relates to CSC-only claims);
- the appropriate authority would be up to €1.5bn in the aggregate and apart from interest or costs (this relates to non-CSC-only claims for compensation that are special relevant claims);
- the appropriate authority would be up to the equivalent in sterling of the aggregate of €700 million and the value of the CSC international pooled funds in the aggregate and apart from interest or costs (this relates to non-CSC-only claims for compensation that are CSC claims);
- the appropriate authority would be up to the equivalent in sterling of the aggregate of €1.5bn and the value of the CSC international pooled funds in the aggregate and apart from interest or costs (this relates to non-CSC-only claims for compensation that are both special relevant claims and CSC claims).

Euratom

Following Brexit, the UK left the European Atomic Energy Community ("Euratom'). To provide for continuity in the civil nuclear sector, the Government put in place relevant measures to ensure that the UK nuclear industry can operate independently of Euratom as a responsible nuclear state and ensure continuity of trade in the civil nuclear sector.

Existing safeguards arrangements under Euratom are replaced by the:

- Nuclear Safeguards (EU Exit) Regulations 2019;
- Nuclear Safeguards Fissionable Material; and
- Relevant International Agreements (EU Exit) Regulations 2019, which were made on 7 February 2019 under the EA 2013 (as amended by the Nuclear Safeguards Act 2018).

These set out the new domestic framework for civil nuclear safeguards, and came into force on 31 December 2020 (the end of Brexit implementation period), with the exception of certain provisions of the Nuclear Safeguards (EU Exit) Regulations 2019 which came into effect on 31 January 2021.

The Nuclear Safeguards (Fees) Regulations 2021 were made in December 2021 and came into force on 1 April 2022 to allow the ONR to recover costs from the nuclear industry for the functions it carries out in relation to nuclear safeguarding. The UK has also signed safeguards agreements with the International Atomic Energy Agency.

The UK has signed bilateral nuclear cooperation agreements with Australia, Canada and the US replacing the nuclear cooperation agreements which were previously in place with Euratom; and has updated the existing bilateral nuclear cooperation agreement with Japan. These set the framework for continued civil nuclear trade after the UK has exited Euratom. The UK and Euratom also entered into a bilateral nuclear cooperation agreement which came in effect on 30 April 2021.

The Nuclear Energy (Financing) Act 2022 ("NEFA") makes provisions for the implementation of the regulated asset base model ("RAB") as a way to finance nuclear power stations in Britain. Under the CfD financing model, developers need to fund the construction of a nuclear power station and can only receive revenue once the plant begins to generate electricity.
In contrast, the RAB mechanism enables regulated revenue stream throughout the construction, commissioning and operation phases of a nuclear plant. A charge will be put on electricity suppliers, the cost of which is expected to be passed down to consumers and paid through their electricity bills.
The Secretary of State has the power to determine whether a nuclear company can benefit from the RAB model on the basis of a set criteria for designation. After a notice about the designation of a nuclear company has been served and published by the Secretary of State, its electricity generation licence will be modified to reflect how the project will be regulated under the RAB model and its allowed revenue. Ofgem will regulate the nuclear company on the basis of these modified terms and conditions. Ofgem will be responsible to determine the amount of the allowed revenue.

Given that the RAB model stipulates that suppliers and consumers will fund new nuclear projects during construction, and possibly through most of the operation phase, the NEFA sets out a special administration regime for nuclear companies financed this way. It also amends provisions of the Energy Act 2008 to clarify the circumstances in which secured creditors and security trustees will not be considered as being 'associated' with site operators for the purposes of funding decommissioning of nuclear sites.

E. Upstream

UK Petroleum sector

The upstream petroleum sector in England. Wales and Scotland is regulated by:

- the NSTA in respect of licensing and regulatory matters (including environmental regulation for offshore operations);
- the Health and Safety Executive ("HSE") through its Energy Division ("ED") in respect of health and safety from work in the offshore oil and gas industry on UKCS;
- the Environment Agency, in respect of environmental matters onshore; and
- the Treasury, in respect of fiscal matters and tax.

The various roles carried out by the NSTA, the ED and the Environment Agency with respect to the petroleum sector are determined by legislation.

This summary is principally concerned with the offshore upstream petroleum sector and will refer to the onshore upstream petroleum sector on an exclusions-only basis.
This summary does not extend to the upstream petroleum sector in Northern Ireland, for which a different devolved regulatory regime applies (and references to the UK should be construed accordingly).

As of 2021, 46.4bn barrels of oil equivalent have been extracted from the UKCS, with a further 4bn to 12bn recoverable barrels of (conventional) oil equivalent estimated to be remaining for extraction, as of 2021.[32]

Unconventional resources

In addition to conventional oil and gas. the UK is host to a developing onshore coal bed methane/vent gas and shale gas sector. From a petroleum licensing perspective there is currently no differentiation between exploitation of conventional and unconventional resources although additional consents will be required, particularly regarding access to coal formations (from the Coal Authority).

Petroleum licensing

Petroleum reserves in the UK are owned by the UK State ("State") (referred to as the Crown). Exploitation of petroleum reserves is contracted out on behalf of the Crown by the NSTA via the award of petroleum licences.

The principal regulator is the NSTA, which administers the petroleum licensing regime on behalf of the relevant Secretary of State. It is an offence to search for, bore for or get hydrocarbons either onshore or offshore unless the relevant person holds a licence in respect of such activities from the NSTA. The State does not itself participate in the petroleum sector, other than in its capacity as regulator, but benefits from the industry through the tax regime.

The NSTA is responsible for awarding petroleum licences. These comprise exploration licences (which cover any area of the UKCS that is not subject to a petroleum production licence) and petroleum production licences, which typically provide for initial and production phases during which the licensees are granted rights to explore for and produce petroleum in a specified area. The relevant legislation is the Petroleum Act 1998.

The NSTA awards petroleum production licences by way of licensing rounds which typically occur annually and invites applications for specific acreage (referred to as blocks or part-blocks) pursuant to the Hydrocarbons Licensing Directive Regulations 1995 (which implement the Hydrocarbons Licensing Directive). Licences incorporate standardised clauses referred to as the model clauses, which are set out in subordinate legislation.

Once a licence has been granted, NSTA consent is required in order to progress beyond the initial licence phase and through the subsequent licence phases. NSTA consent is also required to carry out drilling and development activities and cessation of production, among other things.

Licence structures have developed to incentivise licensees to maximise petroleum recovery by:

- requiring minimum work obligations (such as seismic acquisition and processing and exploration drilling) to be carried out under the licence in order to retain the licence interests;
- preventing licence acreage from being 'hoarded' by:
  - requiring relinquishment of significant areas (typically 50% of the whole area at such time) in order to progress through the licence phases to development and production or to extend any such phase;
  - pressuring companies that are not developing acreage into relinquishing it by describing acreage which joint venture groups are unable to progress as 'fallow' and publicly identifying those joint venture groups;
  - charging escalating 'rental' payments for each square kilometre of licence acreage; and
  - agreeing to optional minimum work obligations; this is typically effected by providing for a 'drill or drop' well which is intended to incentivise seismic acquisition and interpretation without the obligation to drill a well; however, if the option to drill the well is not taken up, then the licence will expire before the end of the relevant licence phase and if it is taken up then it will continue as if the well had always been a minimum work obligation (referred to as a licence with a 'drill or drop' commitment).

Innovate licence

The Innovate Seaward Production Licence ("Innovate Licence"), which was introduced in the 29th Licensing Round and fully implemented in the 30th Licensing Round, has replaced the earlier types of Seaward Production Licence (ie the 'Traditional', 'Frontier' and 'Promote' models). The new Innovate Licence is more flexible in that an applicant for this licence can propose the durations of the initial and second terms among other particulars of the work programme relating to the licence to be undertaken. This licence also has an initial term of up to nine years divided into three phases (Phases A and B are optional while Phase C is compulsory), which are:

- Phase A: a period for carrying out geotechnical studies and geophysical data reprocessing;
- Phase B: a period for undertaking seismic surveys and acquiring other geophysical studies; and
- Phase C: drilling.

A licence may only continue if the initial conditions under the first phase(s) is/are met.

Licensees

As part of the licence application process, prospective licensees must:

- fulfil the NSTA's residency requirements (principally by having a staffed presence in the UK or being a UK-registered company);
- demonstrate its financial capability to fund its licence commitments; and
- have sufficient technical expertise to either act as operator of the licence or, if a non-operator, exercise responsible oversight of the operations.

The NSTA may agree to licensees taking the form of a partnership on a case-by-case basis.

While not a licensing requirement, in addition to assessing financial capability to fund licence commitments, the NSTA will undertake analysis (particularly at the time of approval of any field development or M&A activity) in respect of the ability of the licensees to meet the costs of decommissioning the infrastructure used (or proposed to be used) in the production operations. In this regard, the NSTA's aim is to prevent the UK taxpayer from bearing decommissioning cost/risk.

One of the licensees must act as licence administrator, which is an informal role that includes dealing with licence rental payments and general administration of the licence. Typically, the party acting as operator fulfils this role.

Operatorship

Under the UK licensing regime one licensee must act as operator to organise and supervise the operations within the area covered by the licence. To act as operator in respect of a field, a licensee must be approved by the NSTA. NSTA approval is given once a licensee has demonstrated that it is competent to act as operator and typically this is assessed on the basis of financial, technical and environmental competencies. Equally, such approval can be withdrawn by the NSTA, again, on the basis of its assessed competencies. The NSTA differentiates between operatorship of exploration assets and production assets, and we set out below the matters which it is expected that the NSTA will take into account in assessing an application in respect of each type of operatorship.

For an exploration operator:

- management governance structure and systems (including details of key decision-making personnel and extent of reliance on contractors);
- capacity to ensure environmental protection, details of past record of compliance with environmental legislation and details of management of environmental responsibilities (including the company's environmental policy and environmental management system);
- capability and technical competence to plan, supervise, manage and undertake proposed exploration operations including interfaces with contractors (including details of previous operating experience);
- arrangements for pollution liability; and
- insurance coverage.

For a production operator, the matters set out in the paragraph above regarding exploration operatorship apply and would be tested in more detail with respect to the relevant field and development/production operations. In particular, this includes a detailed proposed management structure of the company in terms of organisation and responsibilities.[33]

Contracting practices

UK petroleum licences govern the relationship between the State and the licensees but do not provide for the relationship among multiple licensees, other than providing that licensees are jointly and severally liable for their obligations under the licence. As a consequence, there is a need for licensees to use contractual mechanisms to provide for the legal relationship as-between the licensees.

The UK petroleum industry has developed a model joint operating agreement ("JOA"), which is maintained by industry body Offshore Energies UK ("OEUK JOA"), formerly called Oil & Gas UK prior to 2022 before it refocused to low carbon technologies. The OEUK JOA is by far the most prevalent form of operating agreement in the UK industry, but it is not compulsory to use this document and there are a variety of other forms of operating agreement used (including the Association of International Energy Negotiators, formerly AIPN, JOA), albeit to a much lesser extent.

In addition to the OEUK JOA, there are a number of further agreements which are reasonably standardised in form and used in the UK petroleum sector, including:

- the NSTA model form licence assignment agreement ("Licence Assignment'), which is the form approved by the NSTA by which transfers of licences may be carried out (other than pursuant to the Master Deed);
- the LOGIC Master Deed ("Master Deed'), which is an executed framework agreement that provides for (i) the streamlining of existing pre-emption provisions in JOAs to which signatories to the Master Deed are party; (ii) the use of standardised transfer documentation to allow for collective assignment/novation of multiple agreements; and (iii) the administration of transfers of petroleum interests using a centralised attorney to execute the underlying documents on behalf of disinterested participants (those who are not acquiring or disposing of interests);
- the LOGIC standard contracts, which are a set of model service contracts providing for matters such as design, construction, drilling and other services; and
- the OEUK model form decommissioning security agreement ("DSA") which is used to provide a framework within which licensees (and other potentially liable parties) provide security in respect of their decommissioning obligations.

Additionally, given the reality that many licences contain multiple sub-groupings of different licensees with different participating interests in different part areas, there is a need to replicate several ownership of each sub-grouping of licensees in each part area. This is typically done by way of a deed of trust and cross indemnity commonly referred to as a trust deed. Unlike the above documents, there is no model form trust deed but it typically follows a relatively standardised structure.

Asset transfers

NSTA consent

Any transfer of rights under a petroleum licence will require prior consent from the NSTA. However, the NSTA has given an 'open permission' for security rights which allows for the creation of charges (other than Scottish law charges) over licence interests without consent, provided that the relevant licensee notifies the NSTA within ten days of the creation of the charge of the size of the loan secured, the licences affected and the identity of the holder of the charge. Typically, acquisition agreements include a condition to procure NSTA consent and completion documentation (such as a Licence Assignment or pursuant to the Master Deed) are only executed once NSTA consent has been obtained. Failure to obtain NSTA consent prior to effecting a transfer constitutes grounds for revocation of a licence by the NSTA.

Transfer process

Asset transfers are typically cumbersome in the UK petroleum industry due to the significant number of contracts (and counterparties to such contracts) that underpin petroleum interests and the consequent need to assign or novate those contracts. As mentioned above, licences may be transferred by way of a Licence Assignment or pursuant to the Master Deed.

In addition, any other contracts, such as JOAs, transportation arrangements, sales agreements and DSAs, will typically be transferred by way of novation agreements or pursuant to the

Master Deed. The Master Deed provides for parties to agreements to enter into one or more documents referred to as execution deeds which provide for the assignment of the relevant licence(s) and the novation of the other relevant agreements.

Changes of control

There is no restriction on the change of control of a licensee, however, upon a change of control, the NSTA may exercise certain powers under the licence to require a further change of control of the licensee and, failing that, to revoke the licence insofar as it relates to that licensee. In practice, licensees avoid this potential risk by seeking from the NSTA a comfort letter that the NSTA will not exercise its powers upon the relevant change of control. Any such comfort, however, will not be published and the NSTA will be mindful not to fetter its discretion. The NSTA confirmed its approach to using its change of control powers in guidance issued in December 2021.

The Energy Bill, introduced by the UK Government in July 2022, contains a provision to amend the model clauses requiring a licensee to apply to the NSTA for consent, in writing, at least three months prior to the desired date of the change of control. Under the new powers contemplated in the Bill, the NSTA would have the power to compel a licensee to provide information and only give consent subject to conditions, whereby any failure to comply is a sanctionable offence. As date of writing, the Bill is progressing through parliament.

Third party access

The UK does not operate a compulsory third party access regime in respect of upstream petroleum infrastructure. However, the Government has powers under the EA 2011 to require third party access to be given and to determine the terms and conditions for such access. We are not aware of the NSTA ever exercising its powers under the EA 2011 (or previous legislation on this matter). In order to provide greater clarity to applicants and infrastructure owners (and obviate the need for NSTA intervention). Oil and Gas UK and DECC (now DESNZ), working with the NSTA, prepared an Infrastructure Code of Practice, which sets out some principles representing the industry view of good practice both in terms of the process and the applicable commercial and contractual terms. DECC (now DESNZ), working with the NSTA, also published guidance on disputes over third party access to upstream oil and gas infrastructure, which takes into account input from the Office of Fair Trading on the application of competition law.

Decommissioning

The decommissioning of offshore oil and gas installations and pipelines is regulated by the Petroleum Act 1998 ("Petroleum Act"). Pursuant to section 29 of the Petroleum Act the Secretary of State may serve a notice on a person requiring them to prepare, submit and (once approved) carry out a decommissioning programme ("Section 29 Notice"). The OGA may only serve Section 29 Notices on persons falling within the categories provided in the Petroleum Act. The OGA's current practice is to serve Section 29 Notices in respect of each piece of offshore infrastructure on the operator and relevant licensees, JOA parties and any other owners of the offshore infrastructure at the time when a field development is approved. There is also scope for the OGA to serve Section 29 Notices on affiliates of these entities.

Holders of Section 29 Notices will often look to enter into DSAs in respect of each petroleum asset. The OGA has indicated that it will look favourably on the release of a transferring licensee from a Section 29 Notice where a satisfactory DSA has been entered into. The form of DSA has been approved by the OGA but the OGA has said it will not itself accept parent company guarantees or security from entities with credit ratings of less than A- (Standard and Poors or Fitch)/A3 (Moody's), although there is flexibility to this criteria depending on the level of risk and decommissioning costs and the other parties to the DSA.

Under section 34 of the Petroleum Act. it is still possible for the OGA to impose decommissioning liabilities on any person who is not subject to a Section 29 Notice but could have been served with such a notice at any time from the date of the first Section 29 Notice ("Section 34 Liability"), even if that person has been released from a Section 29 Notice. The Section 34 Liability brings great uncertainty to parties investing in the UKCS. DECC (now the OGA) has made it clear that it regards this power as something it holds in reserve and, to our knowledge, has never exercised this power to date.

DESNZ provides regulatory functions for offshore oil and gas decommissioning and the Secretary of State has the power to make regulations to charge for the costs associated with carrying out these functions. The current charging scheme is set out in the Offshore (Oil and Gas) Installation and Pipeline Abandonment Fees Regulations 2012, however with the industry evolving and the growing number of activities related to decommissioning, DESNZ has been unable to recover its full costs from the industry, which it considers inconsistent with the 'polluter pays' principle. Following a consultation in 2021, the Government introduced provisions under the Energy Bill that would amend the Petroleum Act and provide the Secretary of State with powers to create a charging scheme that could cover any of the statutory functions undertaken under part 4 of the Petroleum Act, including activities carried out after approval of a decommissioning programme. The charging scheme would specify which functions can be charged for.

Decommissioning liability has become a key issue in UK upstream M&A (and sometimes a stumbling block). Sellers will seek protection from future exposure, while buyers have to grapple with the complexity and assess the risks. In recent years the oil and gas industry, in consultation with DECC, has developed model form documentation for decommissioning security. DECC's involvement is significant as DECC has made it clear that such arrangements may be taken into account as part of DECC's own assessment of decommissioning security risk so long as they meet DECC's specific requirements. The OGA follows the same approach as its predecessor (DECC).

These agreements are separate from the underlying JOAs and provide for security to be held by independent professional trustees. Former owners (who may be direct parties) have rights under such agreements in recognition of their continuing exposure. Net cost and net value estimates used to calculate the level of required security pursuant to such agreements are subject to periodic independent evaluation.

Providers of decommissioning security prefer to issue corporate guarantees rather than procure letters of credit or similar security that tie up capital. Acceptance of guarantees by contractual counterparties turns on whether the guarantor has acceptable credit (usually defined by reference to specified minimum credit rating).

The OGA (now NSTA) Strategy[34] describes how it planned to manage decommissioning in support of maximising economic recovery ("MER"). In practice, MER should work by imposing a legally binding obligation on offshore infrastructure owners, licensees and others to take the necessary steps to assist the Secretary of State in meeting the net zero target.[35]

The OGA's (now NSTA) Decommissioning Strategy sets out how the OGA plans to manage decommissioning in support of the MER Strategy and the OGA's corporate plan. The Decommissioning Strategy is designed to ensure that the MER Strategy is met, including by exploring viable options for infrastructure use prior to decommissioning and that decommissioning is executed in a cost effective way without prejudicing value or regulatory compliance. This Decommissioning Strategy has been supported by the publication of revised Decommissioning Guidelines, which provide detail on the process and requirements for decommissioning offshore oil and gas installations and pipelines.

The key priorities of the Decommissioning Strategy are:

- cost certainty and reduction, including to set a target of a cost reduction relative to the 2015 base case cost in late-life asset management and the execution of decommissioning projects by at least 35%;
- developing an efficient and exportable low-cost and profitable decommissioning capability support by a competent and efficient supply chain; and
- working with the DECC (now BBS) and other relevant parties to identify and evaluate further opportunities to optimise decommissioning scope and to improve industry engagement with regulators.

The NSTA published a revised Decommissioning Strategy[36] designed to support the OGA Strategy, including by aiming to ensure that decommissioning is carried out in a cost-effective way in accordance with regulatory requirements consistent with the OGA Strategy (which includes assisting the Government with meeting its net zero target).[37]

The key priorities of the strategy are:

- planning for decommissioning: driving cost efficiency through effective late-life stewardship, creating a platform for timely delivery;
- commercial transformation: improving market efficiency, and establishing a competitive and sustainable market;
- supporting energy transition from late life into decommissioning: reducing GHG emissions from decommissioning and capitalising on opportunities to reuse or re-purpose infrastructure; and
- technology, processes and guidance: the development and deployment of technology, appropriate regulatory processes and clear guidance underpinning the delivery of the strategy.

In order to establish competitive and sustainable market, the strategy aims to:

- ensure infrastructure owners have clear and detailed plans for decommissioning three to six years prior to production ending;
- encourage collaboration between operators and supply chain, including in the adoption of new procurement models;
- maintain data transparency, where the NSTA will continue to provide as much as possible data for supply chain and infrastructure owners;
- coordinate decommissioning activity between and across infrastructure owners, geographically and in the supply chain in order to achieve decommissioning at scale;
- support energy transition from late life into decommissioning which includes reducing GHG emissions from decommissioning and helping to identify opportunities to repurpose and reuse infrastructure;
- support the development of new technologies, regulatory processes and clear guidance.

On 24 March 2021, the Government announced its commitment to the North Sea Transition Deal with the UK oil and gas sector which provides a blueprint for Government and sector cooperation to decarbonise North Sea production in line with the Government's net zero agenda. As part of the deal, the sector voluntarily commits to ensuring that 50% of its offshore decommissioning and new energy technology projects by 2030 will be provided by local businesses, helping to anchor jobs to the UK.

Tax

By way of summary, the following are the principal direct taxes which can apply to UK oil extraction.

Ring-fenced corporation tax

Ring-fenced Corporation Tax ("RFCT") is a modified form of UK Corporation Tax ("CT"). It applies to companies engaged in UK oil extraction activities (searching, extracting transporting to land and initial storage of oil/gas).

'Ring-fencing' is an important concept in the legislation. Broadly, oil extraction activities are treated as a separate trade, ie a ring-fenced trade. Losses and expenditure from outside the ring-fenced trade cannot reduce profits that are subject to RFCT. Losses within the ring-fence can be carried back as far as 2002, or carried forward against future profits, or group relieved.

As with CT, the starting point in calculating the RFCT profits and losses for a company is the statutory accounts of that company. RFCT is charged at a rate of 30%.

Petroleum revenue tax

Petroleum Revenue Tax ("PRT") is a tax on the profits resulting from UK oil and gas production. Its relevance is mostly historic; PRT was abolished on 16 March 1993 for all fields given development consent on or after that date and the rate of PRT (with respect to the fields that were given consent prior to that date) was reduced to 0% from 1 January 2016 onwards.

PRT is levied on a participator's share of profits from PRT fields (those fields to which PRT still applies). 'Participators' are usually the licensees of the PRT field and PRT is levied on a 'field by field' basis. Broadly, losses realised by participators in PRT fields can be carried forward or back against income of the participant from the same PRT fields.

Rather than using the statutory accounts of the taxpayer as a starting point, the calculation of profits and losses for PRT purposes is based on a strict and detailed set of statutory provisions. There are also various reliefs (such as an 'oil allowance1 and the 'supplement or uplift1) that can reduce the PRT charge for a given field.

A key feature of PRT is that it is deductible as an expense when calculating RFCT and the Supplementary Charge ("SC"). In other words, the payment of PRT reduces the taxable profits that are then subject to RFCT or SC. Computing the effective rate of tax for any given field is therefore not a simple additive process (unless, as is currently the case, PRT is charged at 0%).

Supplementary charge

The SC, ie supplementary charge, is levied on ring-fenced profits and calculated on virtually the same basis as RFCT save that no deductions are allowed for financing costs. The SC is an additional tax charged at 10% on top of the RCFT. Special tax reliefs from the SC may be available in the case of certain fields (for example those associated with complex or challenging extraction technology such as small fields, ultra-high temperature or pressure fields and ultra-heavy oil fields) and/or certain expenditure (as in the case of the brown field allowances).

The Cluster Area Allowance was introduced by the Finance Act 2015, with effect from 3 December 2014, in relation to high-pressure, high-temperature projects to exempt a portion of a company's profits from the SC. The amount of profit exempted is equal to 62.5% of the qualifying capital expenditure a company incurs in relation to a cluster area.

Relief for decommissioning costs

The Corporation Tax Act ("CTA") effectively limits the tax relief available for SC purposes for decommissioning costs. It restricts the use of SC losses occurring as a result of expenditure incurred in connection with decommissioning to 20% for decommissioning carried out on or after 21 March 2012. To tackle the level of uncertainty across the oil industry as to what relief would be available for decommissioning costs when the process starts, the Government has introduced 'decommissioning relief deeds'. Under the Finance Act 2013, the Government can enter into contracts (decommissioning relief deeds) with companies to make payments for the difference between the actual relief given for decommissioning costs and agreed reference amount.

Energy profits levy

The Energy (Oil and Gas) Profits Levy Act 2022 ("Energy Profits Levy Act") introduced a 25% oil and gas profits levy on companies carrying on a ring-fence trade. It applies to profits arising on or after 26 May 2022 and is intended to be temporary in nature. The Government intends to phase out the levy when oil and gas prices return to 'historically more normal levels', but the Energy Profits Levy Act also includes a sunset clause which means that the levy will by default expire on 31 December 2025. It is charged as if it were an amount of corporation tax.

The levy profits or loss for a qualifying accounting period are those that will be determined as a company's ring-fence profits or loss, on the basis that adjustments for certain assumptions are to be made, including leaving out account financing and decommissioning costs, as well as loss relief, group relief and group relief for carried forward loss. Levy relief for loss is made available by way of i) loss carry back of 12 months against previous levy profits (3 years for terminal losses), ii) loss carry forward to set against future levy profits, and iii) group relief in year to another company in the group with levy profits.

In order to encourage investment, levy profits can be reduced by both:

- the normal tax relief for such expenditure; and
- new 80% investment allowance which applies if, in a qualifying accounting period, a company has incurred 'investment expenditure'. This is defined as expenditure that is capital expenditure, operating expenditure or leasing expenditure which has been incurred for the purposes of 'oil-related activities' (broadly covering expenditure incurred in relation to increased oil extraction), provided that it has not been incurred for disqualifying purposes (connected with avoidance arrangements) and does not consist of financing or decommissioning costs.

F. Renewable energy

F.1 Renewable energy

UK renewables share of electricity generation increased to 41.4% in 2022, up from 39.6% in 2021, with the increase largely due to wind and solar generation. Wind generation had a 24.6% share of generation.[38]

There are a number of mechanisms that support renewable electricity generation in GB. The main sources of support are CfD for large-scale low carbon generation and feed-in tariffs ("FIT") for smaller-scale generation (see below). In recent years there have been a number of reforms within the renewable energy sector. For instance, the exemptions from the Climate Change Levy which previously benefited renewable energy generation are no longer available, and the Renewables Obligation is in the process of being replaced by CfD and was closed to new applicants on 31 March 2017. However, operators of stations that meet certain specified conditions may be eligible to apply for a grace period as set out by Ofgem guidance.

Contracts for difference (CfDs)

Introduced through EMR, CfDs support and incentivise large scale low-carbon electricity generation (including renewables, nuclear and fossil fuel plants fitted with CCS technology). CfDs provide increased certainty of revenue levels for generators, which in turn bring forward investment. Eligible generators enter into long-term contracts under which they are paid, or pay, the difference between a market reference price and a fixed strike price (being the price per unit of electricity generated, set at a level determined to be necessary to support the relevant generation technology). The counterparty pays the difference to the generator when the strike price is higher than the market reference price; the generator pays back to the counterparty the difference between the two prices when the market price is higher than the strike price. The counterparty to the CfD is the Low Carbon Contracts Company ("LCCC"), a Government-owned company which became fully operational in 2014. If the generator is able to sell power in the wholesale energy market at the market reference price, the CfD mechanism effectively fixes the price which the generator receives for its electricity.

The fifth CfD allocation[39] ("Round 5"), which has a budget of £205 million, is open to the following technology groups ("pots"):

- pot 1: energy from waste with combined heat and power ("CHP"), hydro (>5MW and <50MW), landfill gas, offshore wind, onshore wind (>5MW), remote island wind (>5MW), sewage gas, and solar photovoltaic ("PV") (>5MW)
- pot 2: advanced conversion technologies (ACT), anaerobic digestion (AD) (>5MW), dedicated biomass with CHP, floating offshore wind, geothermal, tidal stream, and wave

The delivery years for pot 1 are 2025/26, 2026/27 and 2027/28, and for pot 2 are 2026/27 and 2027/28.

The results of Round 5 are expected in July 2023.

Offtaker of last resort

The offtaker of last resort ("OLR") was introduced as part of EMR and commenced in October 2015. Concerns from the renewables industry about the lack of a route to market led to the introduction of a 'back-stop PPA' ("BPPA") for renewable generators holding a CfD. Under a BPPA, the OLR mechanism supplements and supports the new CfDs by giving additional comfort as to the minimum revenues that a project will receive. It is designed to reduce the risk of market failure, boost competition and, ultimately, reduce costs passed down to consumers. Eligible generators (namely, eligible renewable CfD generators) are provided with a guaranteed route to market for their power through a short-term BPPA with an OLR. The duration of a BPPA can be no longer than 12 months and the purchase price will be a specified discount below the market reference price.

This alternative route to market is facilitated by a competitive auction process. Ofgem identifies mandatory licensed suppliers who must participate in the OLR auction that year. All licensed suppliers can bid in the auction.

Renewables obligation

The Renewables Obligation ("RO") requires licensed suppliers to source a certain amount of electricity from renewable sources. It has been the principal support mechanism for large-scale renewable electricity generation but is in the process of being replaced by the CfD regime. Under the RO regime, licensed suppliers are required to surrender a certain number of Renewables Obligations Certificates ("ROCs") for each MWh of electricity they supply in each year to Ofgem. This demonstrates that a supplier has met its obligation to source electricity from renewable sources. ROCs are awarded to accredited renewables generators in respect of each MWh of renewable generation and can then be passed on to suppliers and/or traded on a secondary market. Suppliers meet their renewable obligation by purchasing these certificates and/or making a financial payment into the 'Buy-Out Fund'. Proceeds from the Buy-Out Fund are then recycled to those suppliers who met their obligations through the purchase of ROCs. The level of the obligation escalates on an annual basis.

With the exception of limited grace periods, the RO closed to all new applicants on 31 March 2017 pursuant to the Renewables Obligation Closure Order 2014. The closure also included the Renewable Obligation Scotland and the Northern Ireland Renewables Obligation. From April 2017, support for renewable energy generation has been available through the CfD mechanism instead. The RO, again subject to grace periods, was closed to new onshore wind generation from 13 May 2016 in GB and to new solar PV generating capacity on 1 April 2015 in England, Scotland and Wales. The grace periods allowed generators affected by the closure to be accredited under the RO in certain circumstances after the closure date. There have been five grace periods available for generating capacity (excluding solar PV and onshore wind). Although these individual grace periods were to end on different dates, guidance issued by Ofgem in April 2018 indicated that all grace periods would close by 31 January 2019. Where a generator is already accredited within the RO on 31 March 2017, it will continue to receive support under the RO until March 2037 at the latest. In order to avoid market volatility in the final years of this period, namely 2027 to 2037, the existing ROC regime (tradable commodities of no fixed price) will be replaced with a Fixed Price Certificate ("FPC") scheme. ROCs will have a fixed price based on their long-term value and these FPCs will be bought from generators by a purchasing body.

Feed-in tariffs (FITs)

A feed-in tariff is a financial incentive Government scheme for small-scale electricity generation from renewable or low-carbon energy sources. The scheme involves participating licensed electricity suppliers making payments on both the generation and export from eligible installations. Generation projects up to a capacity of 5MW for wind, hydro, solar PV or anaerobic digestion and up to 2kW for micro combined heat and power ("Micro CHP") are included.

The FIT scheme was temporarily suspended from 15 January 2016 to 7 February 2016, and changes relating to deployment caps and energy efficiency requirements for solar PV were introduced. Extensions to existing accredited FIT installations which were commissioned on or after 15 January 2016 are no longer eligible for the FIT scheme. On 1 April 2017, deployment caps and contingent degression specifically in relation to Micro CHP installations were introduced, and future generation tariff rates for anaerobic digestion installations were altered. The FIT scheme was closed to new applications from 1 April 2019 subject to limited grace periods for some installations which were commissioned before this date.

Renewables energy guarantees of origin

The Renewable Energy Guarantees of Origin (“REGO”) is a scheme that shows final consumers the proportion of energy produced from renewable sources. As part of the Fuel Mix Disclosure obligations of energy suppliers, the REGO aims to encourage transparency by allowing customers to see how much of their energy has been produced from renewable sources. Energy generating stations in the UK apply for REGOs through Ofgem's Renewables and CHP Register. Ofgem then issues REGO certificates to renewable energy suppliers (one certificate for every MWh of eligible renewable output). REGO certificates contain information on when, where and how the renewable energy was produced. Suppliers use the certificates to demonstrate the proportion of renewable energy from an energy supplier's overall energy mix. Corporate customers may also use REGOs as a way of evidencing their green credentials, for example under the Greenhouse Gas Protocol.

The Government continues to recognise REGOs issued in EU countries, allowing electricity suppliers in the UK to continue to use both EU and UK REGOs to comply with their fuel mix disclosure requirements, thereby protecting existing supply contracts from being compromised. However, UK REGOs are no longer recognised in the EU.[40]

F.2 Renewable pre-qualifications

Before taking part in a capacity auction, applicants that are eligible to offer capacity must go through a pre-qualification process run by the EMR Delivery Body (the "Deliver Body")[41]. The pre-qualification process takes place four months before each auction.[42]

Applications for participation in the capacity markets must be for a capacity type that falls into the definition of a capacity market unit ("CMU"), which is any of the following:

- a 'generating CMU', which is electricity generation or electricity storage as defined in Capacity Regulations that can be either capacity which is already built or capacity which is not yet built;
- a 'demand side response ("DSR") CMU', which can be either already operational or equipment that will meet these conditions prior to the commencement of the delivery year for which capacity market support is awarded;
- an 'interconnector CMU', which is any international 'electricity interconnector'. For the capacity markets, only that part of the interconnector situated within GB jurisdiction qualifies. The interconnector can be either commissioned or not yet built;
- a relevant CMU located in GB or GB's offshore area with a connection capacity of 2MW or more (subject to a very narrow exemption, allowing a 500kW minimum for generation-derived DSR participating in the second DSR specific transitional auction).

Wind and solar renewable technology can participate in the capacity market. The key among these requirements for eligibility to apply for the capacity auctions include that the applicant does not hold any of the following:

- a capacity agreement for the same capacity for a delivery year to which the relevant capacity auction will relate;
- low carbon generation support under the small scale Feed-in Tariff, Renewable Heat Incentive, Renewable Obligation Order or Contract for Difference Scheme in respect of the relevant capacity;
- certain grants under the New Entrant Reserve (NER) 300, the Energy Act 2010 Carbon Capture and Storage (CCS) demonstration project scheme, or the Science and Technology Act 1965 CCS support scheme;
- a Short Term Operating Reserve (STOR) contract with National Grid that was entered into before 1 August 2014 (unless this contract is to be terminated before the relevant capacity market delivery period commences). STOR contracts entered into after 1 August 2014 (together with other types of balancing service contracts with National Grid) can be held along with a capacity agreement;
- for certain applications, a capacity agreement terminated in the previous two years, eg where the CMU has been deemed a defaulting CMU due to reasons such as deemed unreasonable business behaviour or concerns over market manipulation, or an excluded CMU, which may have self-declared as retired or previously have declared itself non-operational.

Under the rules, capacity providers must declare certain low-carbon support received by the new build renewable technologies being introduced into the capacity market. Support declared by a capacity provider is deducted from capacity payments until fully offset, in order to prevent cumulation of state aid; outstanding support from a capacity provider can be directly recovered if it cannot be fully offset by deductions from remaining capacity payments. The amount of support directly recovered in this way cannot exceed the total amount of the capacity payments paid to the capacity provider.

Although participation in the capacity market is voluntary, a provider of an existing generating CMU or an existing interconnector CMU must formally opt-out of the capacity market if it does not wish to bid in a capacity auction and does not apply for pre-qualification[43].

The opt-out notification should state whether the CMU will be:

- Closed down, decommissioned or otherwise non-operational by the start of the relevant delivery year.
- Temporarily non-operational during the winter of the relevant delivery year.
- Remaining operational during the relevant delivery year.

The Capacity Market Rules have been modified[44] to temporarily allow plants that have been mothballed for longer than 24 months to apply to pre-qualify for Capacity Market auctions. This only applies for the 2022 pre-qualification window and the associated auctions in 2023.

The Delivery Body must consider applications for pre-qualification in accordance with the Capacity Market Rules, and inform the applicants of its decisions. Information from the pre-qualification process about opted-out capacity is also used to adjust the amount of required capacity.[45]

An application can have one of the three possible outcomes reflecting its status:

- Pre-qualified: The Application is pre-qualified to participate in the auction. Depending on the CMU type, some pre-auction activities may need to be completed to confirm participation in the auction.
- Conditionally pre-qualified: The application is pre-qualified, subject to fulfilling one or more conditions before the auction. Being conditionally prequalified will require applicants to either lodge credit cover or submit relevant planning consents, or both. Once the conditions are fulfilled, the application status changes from conditionally pre-qualified to pre-qualified.
- Rejected: The application is rejected and is not eligible to participate in the auction.

Unsuccessful applicants may dispute the decision, initially to the Delivery Body, and then to Ofgem, with final recourse to the High Court. The Delivery Body can consider information submitted by applicants to correct non-material errors in their pre-qualification applications. This is intended to reduce the risk of CMUs being excluded from participating in auctions due to non-material errors.

After making its pre-qualification decisions, the Delivery Body must notify the Secretary of State of the capacity of:[46]

- CMUs that are eligible to bid in the forthcoming auction.
- CMUs that were rejected in pre-qualification.
- Generating or interconnector CMUs that have "opted-out" for the relevant delivery year.

F.3 Biofuel

The use of bioliquids to generate electricity is supported through the Renewables Obligation so long as the sustainability criteria imposed by the Renewable Energy Directive are met. The use of biofuels for transport is supported through the Renewable Transport Fuels Obligation ("RTFO"). The RTFO is assessed based on who owns the fuel when it crosses the duty point (and fuel duty is chargeable). Suppliers of road and non-road mobile machinery (for example, bulldozers, and excavators) ("NRMM") fuel, who supply more than 450,000 litres of petrol, diesel, gas oil or renewable fuel in a given year, are subject to the RTFO.

Owners of biofuel at the duty point are awarded one Renewable Transport Fuel Certificate ("RTFC") per litre of biofuel, or kilogramme of biomethane, supplied. RTFCs may be traded between participants in the scheme. At the end of each yearly obligation period, suppliers of road and NRMM fuel demonstrate compliance with the RTFO by redeeming the appropriate number of RTFCs to demonstrate that they have supplied the required volume of biofuel. Alternatively, obligated suppliers can pay a buy-out price per litre of obligation. The buy-out price is set in the legislation underpinning the RTFO. Suppliers are permitted to carry over RTFCs from one obligation period to the next, provided that no more than 25% of the supplier's obligation to supply biofuel for the later year is met by carrying over RTFCs.

Under the amended RTFO Order the obligation has been extended to suppliers of fuel for NRMM. Particular renewable gaseous fuels are favoured to reflect their higher energy content: each kilogramme of biomethane is awarded 1.9 RTFCs and each kilogramme of biopropane or biobutane is awarded 1.75 RTFCs.

Renewable aviation fuel and renewable fuels of non-biological origin ("RFNBOs") are also rewarded (but not obligated) under the scheme. Biofuels derived from crops grown specifically for energy and RFNBOs are eligible for 2 RTFCs per litre or kilogramme supplied. However, a cap on the contribution that crop-derived biofuels can make towards discharging a supplier's obligation, the crop cap, has also been introduced.

This crop cap stands at 4% as an amount of the total relevant fuel supply. This cap will be periodically reduced, ultimately to 2% by 2032. There is also a target for the amount of a specific sub-set of advanced fuels, known as 'development fuels', as a share of the total relevant fuel supply; this target stands at 0.1% and will increase annually, ultimately to 2.8% by 2032.

G. Climate change and sustainability

G.1 Climate change initiatives

The Climate Change Act 2008 is the framework legislation containing statutory targets for GHG emissions reduction. The Act also established the Committee on Climate Change ("CCC"), which is an independent, statutory public body, tasked with assessing how the UK can best achieve its emissions reduction targets for 2020 and 2050 and the progress that is being made towards meeting statutory carbon budgets. The Act requires the CCC to advise on the level of each five-year carbon budget, how much effort should be made towards meeting the targets by the UK, and how much effort should be made by the part of the economy covered by cap and trade schemes (the traded sector), and by the rest of the economy (the non-traded sector).

Under the Paris Agreement,[47] the UK has obligations to communicate action plans setting out its objectives to tackle climate change and to peak GHG emissions as soon as possible and to reduce them from there on. The signatories of the Paris Agreement must also communicate nationally determined contributions to address climate change. The Paris Agreement has repeatedly been referenced in reports relating to the Government's climate change policy[48] and forms a notable part of the context of the Government's climate change policy but no measures have yet been taken purely on the basis of the Paris Agreement.

Under the Act, the UK is obliged to reduce emissions by 100% by 2050, thereby committing the country to be net-zero by mid-century (compared to 1990).[49] The UK Government has also implemented a 78% emission reduction target for 2035.[50]

The Industrial Decarbonisation strategy sets out how industry can decarbonise in line with net zero while remaining competitive and without pushing emissions abroad.[51] Separately, the North Sea Transition Deal sets out an ambitious plan for how the UK's offshore oil and gas sector and the government will work together to deliver the skills, innovation and new infrastructure required to meet stretching GHG emissions reduction targets.

Directed more generally at the economy at large, the UK's Net Zero Strategy: Build Back Greener[52] sets out policies and proposals for decarbonising all sectors of the UK economy to meet the UK's net zero target by 2050.

G.2 Emission trading

UK ETS

The UK commenced participation in the UK ETS on 1 January 2021, having left the EU ETS following the UK's leaving of the EU.

The UK ETS has to date been closely aligned to the EU ETS, which was transposed into UK law by the Greenhouse Gas Emissions Trading Scheme Regulations 2003. These have been replaced most recently by the Greenhouse Gas Emissions Trading Scheme Regulations 2012 ("2012 Regulations").

Installations engaged in the activities set out in Schedules 1 and 2 of the Greenhouse Gas Emissions Trading Scheme Order 2020 are within the scope of the UK ETS and regulated by the 2012 Regulations.

The UK ETS applies to the power generation sector, energy intensive industries and aviation.[53] Operators of installations covered by the EU ETS must hold a GHG permit (a statutory permit required by the regulation for installations which emit over a specified level of GHGs). Permits contain conditions that must be complied with, including monitoring and reporting requirements. The quantity of allowances that are allocated to the operator of an EU ETS installation represents the quantity of GHGs that the installation can emit without paying a financial penalty. Accordingly, it is the permit, and not the allowances, that authorises the emission of GHGs.

Carbon tax

The UK Government has announced it will introduce a Carbon Emission Tax ("Carbon Tax") to address the UK's carbon reduction commitments under the Climate Change Act 2008. The date from which the Carbon Tax would be applicable will be confirmed by the UK Government 'in due course'. Under this replacement scheme, all stationary installations which would have otherwise been captured by the EU ETS will have to pay £16 for each tonne of CO_2 emitted over and above the relevant installation's emission allowance. The respective installation's free allowance allocation rate will be set at future UK fiscal events.

The Government has published a draft statutory instrument which amends provisions of the GHG Regulations so that the existing monitoring, reporting and verification requirements for GHG emissions will remain operable, as these will provide information to allow for the implementation of the Carbon Tax.

G.3 Carbon pricing

The carbon price floor ("CPF") is a mechanism under the EMR which is used to support the price of carbon.

CPF aims to encourage low-carbon electricity generation in GB by increasing the price paid for CO_2 emissions. Fossil fuels used to generate electricity are taxed through the climate change levy or fuel duty.

Businesses using fossil fuels to generate electricity are required to pay the climate change levy or fuel duty at the carbon price support ("CPS") rate on those fuels. Tax becomes due when a quantity of a CPS rate commodity arrives at the site of the generating station, and is payable by the generating station's owner.

The CPF does not apply in Northern Ireland.

On 30 March 2023, the UK Government published a public consultation to consider potential policy measures to mitigate carbon leakage[54] risk in the future in the UK and help grow the market for low carbon products.[55] The policies under consideration include a carbon border adjustment mechanism ("CBAM") and mandatory product standards ("MPS"). The potential measures also include an emissions reporting measure aimed at supporting the implementation of such mitigation policies. The consultation is open for submissions until 22 June 2023, following which it will be reviewed by HM Treasury and the Department for Energy Security and Net Zero.

G.4 Capacity markets

See section A.3.

H. Energy transition

H.1 Overview

UK's latest vision of its energy transition is summarised in the 'Powering up Britain' policy,[56] which combines the ambition for greater energy security with the goal of becoming a net zero economy by 2050.

By replacing imported fossil fuels with wind, solar, hydrogen and nuclear power plants the UK plans to decrease energy prices, decouple itself from foreign dependencies, grow the domestic economy and become a net zero economy at the same time. The UK aims to double its domestic electricity generation by the late 2030s and to decarbonise the power sector by 2035.

H.2 Renewable fuels

Hydrogen

The UK Government's Hydrogen Strategy sets out that, while building the hydrogen economy, the most appropriate approach is to support multiple production routes, ie the production of green hydrogen (electrolysis), blue hydrogen (natural gas), and pink hydrogen (electrolysis via nuclear power) (together "low carbon hydrogen").

The Hydrogen Strategy indicates that the use of low carbon hydrogen may amount to about 20%-35% of the UK's final energy consumption in 2050, which is equivalent to about 250TWh-460TWh. It is also envisaged that high-grade British hydrogen will be produced for export.

To reach these levels of hydrogen use by 2050, the Government has identified key research and innovation needs to reaching commercial deployment of hydrogen. This includes the need to demonstrate that hydrogen is an efficient and reliable resource that can be produced at low-cost at increasing scales, which will enable it to be ready to be commercially deployed in the future.

The Government's 'British energy security strategy'[57] ("BESS") doubles the UK's ambitions for the production of low carbon hydrogen capacity from 5GW to up to 10GW by 2030. While acknowledging that the UK had virtually no low carbon hydrogen in the energy system, the BESS noted that by investing in the North Sea, renewable and nuclear the UK would be well-placed to exploit all forms of low carbon hydrogen production. To support this ambition of reaching 10GW or low carbon hydrogen capacity by 2030, the BESS sets out a number of supports to be implemented by 2025. These supports include the running of annual allocation rounds for electrolytic hydrogen, with the aim of having up to 1GW of electrolytic hydrogen in construction or operation by 2025, designing new business models for hydrogen transport and storage infrastructure, and levelling the playing field through putting in place a hydrogen certification system. The aim of the certification system is to ensure that hydrogen imported into the UK is of the same high standards that are envisaged for UK companies.

The Government has continually reiterated its commitment to developing the UK's low carbon hydrogen economy in, among other things, its hydrogen strategy updates, its Hydrogen Sector Development Action Plan, and the promotion of the production of hydrogen through investment and financial support.

Funding support

The Government is committed to supporting research and development of prototypes with the aim of assisting the availability of new technologies to enable commercial deployment of hydrogen and has launched several funding schemes to support this initiative.

The Net Zero Hydrogen Fund ("NZHF") of £240 million provides capital and development expenditure to support the commercial development and deployment of low carbon hydrogen production. The fund is open to individual applicants and collaborations.

Ammonia

The Government has made legally binding commitments to reduce ammonia emissions under the Convention on Long Range Transboundary Air Pollution (CLRTAP) and the National Emissions Ceiling Regulations (NECR). Under these obligations, the UK is required to reduce ammonia emissions by 16% by 2030, compared to emissions in 2005.

Ammonia emissions in the UK stem mainly from agriculture, industry and waste, with agriculture accounting for 87% of total ammonia emissions in the UK in 2021. The UK's Clean Air Strategy[58], among other things, outlines plans to support a reduction of emissions from ammonia in farming, which include practical elements such as the provision of grants, providing a national code of good practice and regulating to reduce to reduce ammonia emissions.

Liquid form ammonia is a carbon-free dispatchable hydrogen carrier and is considered could allow for cost-effective storage and distribution of large quantities of renewable energy. Feasibility studies and projects are underway, such as the Ammonia to Green Hydrogen Project[59] , which aim to develop commercially viable technologies and pathways that ammonia could be used to enable the realisation of the hydrogen economy.

H.3 Carbon capture and storage

The Government's 'UK capture, usage and storage deployment pathway: an action plan' commits the UK to invest £20 million in supporting the construction of CCUS technologies at industrial sites across the UK as part of a £45 million commitment to innovation and set out how it envisages to enable the first CCUS facility in the UK. The plan also sets out that the Government will invest up to £315 million in decarbonising the industry, including through the potential use of CCUS, and begin to work with the OGA, the industry and Crown Estate to identify existing oil and gas infrastructure which could be transformed to CCUS projects.

The framework for the licensing of CO_2 storage and the enforcement of the licence provisions is provided for under the EA 2008. It also applies existing offshore legislation (eg, the decommissioning legislation in the Petroleum Act 1998) to offshore structures used for the purposes of CO_2 storage. The Act also asserts the UK's rights to the use of the offshore sub-surface space for the storage of CO_2. The EA 2010 contained further provisions to enable the Secretary of State to provide financial assistance to CCS projects. The EA 2011 facilitates the development of CCS demonstration projects by amending the EA 2008 to provide the Secretary of State with a discretionary power to designate an offshore installation or pipeline, which, when used for a demonstration project, removes the possibility that the organisation that had previously used the facilities only for petroleum production activities can be made liable for its decommissioning. The EA 2011 also amends the Pipelines Act 1962 to allow the compulsory acquisition of rights to transport CO_2 from the owners of the land through which pipelines pass. In relation to CCS, the CCS Directive is fully implemented.

H.4 Oil and gas platform electrification

Plans for oil and gas platform electrification are part of the UK North Sea Transition Deal between the UK Government and the oil and gas sector. The transition deal aims to tackle the challenges of transitioning to a net zero economy and sets up emission reduction targets of 50% by 2030 against a 2018 baseline.[60] One of the short-term priorities is to reduce and eventually eliminate upstream emissions in exploration and production in the gas and oil sector. To achieve this, the industry, among other things, agreed to invest and deploy new technologies that allow for a step-change in emissions' reductions, in particular platform electrification. In return, the UK Government promised to identify and quickly deal with barriers to platform electrification.

In its 2021 Emissions Monitoring Report, the NSTA identified that in 2020 over 70% of all offshore upstream oil and gas industry emissions were the result of burning either natural gas or diesel for fuel, to power energy intensive processes on oil and gas platforms. It is estimated that by electrification of oil and gas platforms between 2-8 Mt CO_2 could be abated by 2030.[61]

To achieve the targets set out in the transition deal, the NSTA calculated that at least two operational electrification projects will be needed in the 2020s.

H.5 Industrial hubs

In its Industrial Decarbonisation Strategy, the UK Government has identified six industrial clusters in the UK: Humberside, South Wales, Grangemouth, Teesside, Merseyside and Southampton. These clusters emit around half of the industry's CO_2 emissions in the UK. While they contribute significantly to CO_2 emissions, their concentration in clusters also offers an excellent starting point for the reduction of emissions. Low carbon projects can be implemented in these clusters particularly efficiently, eg through shared infrastructure. Considering this, the UK Government set the aim to have the world's first net zero industrial cluster by 2040 and four low carbon industrial clusters by 2030.[62]

These clusters are also planned to be the starting point for a new carbon capture industry. The goal is to deploy CCUS in two industrial clusters by the mid-2020s, aiming for four of these sites by 2030, with the goal of capturing up to 10MtCO_2 per year. To achieve this goal, the UK Government has set up a £1bn Carbon Capture and Storage Infrastructure Fund boost the research and development in the sector.[63]

H.6 Smart cities

World Bank figures show that 84% of the UK's population in 2021 lived in urban areas, a percentage which continues to increase. On current estimates, 75% of global energy consumption occurs in cities, largely accounted for by buildings and transport. According to C40, which is a collaboration of almost 100 world leading cities working to deliver climate change solutions, an average of 60% of emissions is caused by the energy required to power, heat and cool buildings. Reducing emissions from cities is therefore critical in moves to meet net zero targets.

Smart systems play a critical role in the transition from fossil fuels to low carbon technologies. The UK Smart Systems and Flexibility Plan defines 'smart' as 'the ability of a device to respond in real time to communication signals, using digital technologies, to deliver a service'. Smart systems have been used for some time to facilitate the operation and management of real estate assets, using tech platforms in smart buildings for a variety of purposes from pure information gathering to energy management systems. Similarly, smart cities use smart, flexible systems to find solutions to the various challenges that they face. In terms of emissions' reduction, such systems contribute to flexibility in energy management such as by shifting demand, whether temporally or spatially across grids. This can be achieved by, eg, smart EV chargepoints which promote charging when demand for electricity is low, or by lighting, heating or cooling public spaces only when demand requires.

Such systems operate by collecting, processing and acting on electronic data from thousands of sensors and devices connected to the internet which provide information on how buildings, transport and public spaces are being used by people. Such systems may also detect where energy may be required from the grid and from where it might be made available, such as from vehicle-to-everything ("V2X") technology, battery storage or renewable energy generated by buildings, eg by solar capacity. The Internet of Things enables providers to anticipate and respond to consumer demand and allows consumers to adapt their behaviours to match times of abundant (so generally cheaper) supply. However, this reliance on data sharing and technology information systems gives rise to data protection issues and cybersecurity considerations. Different legal considerations may apply depending on whether data is collected in the public or the private realm. Legal agreements regarding data use and information sharing, or to site sensors and collection devices on private land, may be required between building owners and public authorities or service providers and between building owners and occupiers. However, given the objective of creating sustainable, smart, net zero cities, these challenges do not seem unsurmountable.

I. Environmental, social and governance (ESG)

The UK has shown an increased commitment to ESG in a regulatory and legislative context, specifically in relation to disclosure obligations.

All UK quoted companies have been required to report[64] on their GHG emissions as part of their annual directors' report and the Government has encouraged all other companies to undertake similar reports voluntarily. The Streamlined Energy and Carbon Reporting[65] framework expands similar reporting requirements beyond quoted companies. Large unquoted companies and large LLPs are required to report their UK energy use and associated GHG emissions (as a minimum relating to gas, electricity and transport fuel), an intensity ratio and information relating to energy efficiency. In addition to these duties, medium-sized and large quoted companies are also required to report their total global energy use and information relating to energy efficiency action.

The FCA's Policy Statement (PS20/17), and final rules and guidance in relation to mandatory climate-related financial disclosures for premium listed companies, are part of the FCA's sustained focus on climate-related issues in the UK. The FCA's Policy Statement (PS21/23) contains equivalent rules for standard listed companies which apply to accounting periods beginning on or after 1 January 2022. Both sets of requirements oblige listed companies to include a statement in their annual report, which sets out whether the annual report (or another document) contains disclosures consistent with the Task Force on Climate-Related Financial Disclosures ("TCFD") Recommendations and Recommended Disclosures, and to explain the reasons why if they have not made such disclosures.

The strategic report requirements contained in the Companies Act 2006 and Limited Liability Partnership Act 2000 require all listed and certain large companies and LLPs to include climate-related disclosures in their strategic reports.[66] These requirements, while differently worded, are also closely aligned with the TCFD Framework and reporting in line with the TCFD disclosures is understood to ensure compliance under this obligation.

Endnotes

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2. Implemented by the Electricity and Gas (Internal Markets) Regulations 2011, which amended the Gas Act 1086 and the Electricity Act 1989.
3. See www.retailenergycode.co.uk.
4. See www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-updates-our-minded-positions.
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26. Following the enactment of the Electricity and Gas (Internal Markets) Regulations 2011.
27. See www.gov.uk/guidance/oil-and-gas-petroleum-licensing-guidance.
28. See section 43 of the Infrastructure Act 2015.
29. The Electricity and Gas (Internal Markets) Regulations 2011 (which implemented the Third Energy Package) amended the Gas Act 1986 and the Petroleum Act 1998 with the result that access to both onshore and offshore gas storage facilities, as well as LNG facilities, is now governed by the amended Gas Act 1986.
30. See www.ofgem.gov.uk/energy-policy-and-regulation/policy-and-regulatory-programmes/smart-meter-transition-and-data-communications-company-dcc/smart-meter-transition-and-data-communications-company-dcc-supplier-smart-metering-installation-targets#:~:text=In%20January%202022%20a%20new,to%20binding%20annual%20installation%20targets.
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32. See www.nstauthority.co.uk/media/8394/reserves-and-resources-2022.pdf.
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34. The OGA Strategy, available at www.nstauthority.co.uk/news-publications/publications/2020/the-oga-strategy.
35. See www.nstauthority.co.uk/media/7538/decommissioning-strategy-may-2021.pdf.
36. See www.nstauthority.co.uk/news-publications/publications/2021/decommissioning-strategy.
37. See section 4 (page 6) of the revised Decommissioning Strategy, available at www.nstauthority.co.uk/news-publications/publications/2021/decommissioning-strategy.
38. See www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1147249/Energy_Trends_March_2023.pdf.
39. See www.gov.uk/government/publications/contracts-for-difference-cfd-allocation-round-5-core-parameters.
40. See www.ofgem.gov.uk/environmental-and-social-schemes/renewable-energy-guarantees-origin-rego/renewable-energy-guarantees-origin-rego-electricity-suppliers-and-generators/guarantees-origin-goos.
41. See EMR Portal, available at www.emrdeliverybody.com/cm/home.aspx.
42. Chapter 3 of the Capacity Market Rules sets out the details of the process of applying for pre-qualification, and the information that must be submitted. Available at www.gov.uk/government/publications/capacity-market-rules.
43. Rules 3.1 and 3.11, Capacity Market Rules.
44. See Capacity Market (Amendment) (No 2) Rules 2022.
45. Chapter 4 of the Capacity Market Rules sets out the detailed requirements for the Delivery Body's consideration of pre-qualification applications.
46. See Regulation 23, Electricity Capacity Regulations 2014.
47. The Paris Agreement entered into force on 4 November 2016 and was ratified by the UK on 17 November 2016. The overall objective of the Paris Agreement is to ensure that the global temperature increases above pre-industrial levels remains at no more than 2 degrees Celsius, but preferably 1.5 degrees.
48. See, for example, www.theccc.org.uk/wp-content/uploadv'2019/05/Net-Zero-The-UKs-contribution-to-stopping-gtobal-warming.pdf, which intermittently reference the Paris Agreement.
49. See the Climate Change Act 2008 (2050 Target Amendment) Order 2019, section 2(2).
50. See Carbon Budget Order 2021 (SI 2021/750).
51. HM Government, 'Industrial Decarbonisation Strategy' (March 2021) CP 399, available at www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/970229/Industrial_Decarbonisation_Strategy_March_2021.pdf.
52. HM Government, 'UK's Net Zero Strategy: Build Back Greener' (October 2021), available at www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1033990/net-zero-strategy-beis.pdf.
53. Available at www.legislation.gov.uk/uksi/2020/1265/contents/made.
54. According to the European Commission, "Carbon leakage refers to the situation that may occur if, for reasons of costs related to climate policies, businesses were to transfer production to other countries with laxer emission constraints. This could lead to an increase in their total emissions. The risk of carbon leakage may be higher in certain energy-intensive industries." See www.climate.ec.europa.eu/eu-action/eu-emissions-trading-system-eu-ets/free-allocation/carbon-leakage_en. This could happen, for example, where a company transfers production from one country to another country in an effort to avoid the higher costs of carbon.
55. See www.gov.uk/government/consultations/addressing-carbon-leakage-risk-to-support-decarbonisation.
56. See www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1147340/powering-up-britain-joint-overview.pdf.
57. See www.gov.uk/government/publications/british-energy-security-strategy/british-energy-security-strategy.
58. See www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/770715/clean-air-strategy-2019.pdf.
59. See for example, the Ammonia to Green Hydrogen Project, available at www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/880826/HS420_-_Ecuity_-_Ammonia_to_Green_Hydrogen.pdf.
60. See www.gov.uk/government/publications/north-sea-transition-deal/north-sea-transition-deal-accessible-webpage.
61. 2021 NSTA's Emissions Monitoring Report, p. 19, available at www.nstauthority.co.uk/media/7809/emissions-report_141021.pdf.
62. Industrial Decarbonisation Strategy, March 2021, Annex 3, www.assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/970229/Industrial_Decarbonisation_Strategy_March_2021.pdf. See also www.gov.uk/government/publications/design-of-the-carbon-capture-and-storage-ccs-infrastructure-fund/the-carbon-capture-and-storage-infrastructure-fund-an-update-on-its-design-accessible-webpage.
63. See www.gov.uk/government/publications/design-of-the-carbon-capture-and-storage-ccs-infrastructure-fund/the-carbon-capture-and-storage-infrastructure-fund-an-update-on-its-design-accessible-webpage.
64. The Financial Services and Markets Act 2000 (Over the Counter Derivatives, Central Counterparties and Trade Repositories) Regulations 2013.
65. See Companies (Directors' Report) and Limited Liability Partnerships (Energy and Carbon Report) Regulations 2018.
66. See Companies (Strategic Report) (Climate-related Financial Disclosure) Regulations 2021.

Glossary

AAU	assigned amount unit
AC	alternating current
ACER	Agency for the Cooperation of Energy Regulators
AEC	Atomic Energy Commission
AWP	Adria-Wien-Pipeline
bcm	billion cubic metres
BCR	balancing circle representative
BoA	board of appeal
BRP	balance responsible party
CBAM	carbon border adjustment mechanism
CBCA	cross-border cost allocation
CCAP	coordinated capacity allocation procedure
CCP	central counterparty
CCR	capacity calculation regions
CCS	carbon capture and storage
CDM	clean development mechanism
CEF	Connecting Europe Facility
CEF-E	Connecting Europe Facility for Energy
CEGH	Central European Gas Hub
CER	certified emissions reduction
CEREMP	Centralised European Register of Energy Market Participants
CfD	contract for difference
CHP	combined heat and power
CIS	Commonwealth of Independent States
CMP	congestion management procedure

CNG	compressed natural gas
CO2	carbon dioxide
COP21	2015 United Nations Climate Change Conference
CPI	consumer price index
DODO	dealer owned dealer operated
DSO	distribution system operator
E&P	exploration and production
ECC	European Commodity and Clearing AG
ECJ	European Court of Justice
ECN	European Continental Network
EDI	electronic data interchange
EEA	European Economic Area
EEPR	European Energy Programme for Recovery
EERA	European Energy Research Alliance
EEX	European Energy Exchange AG
EEZ	exclusive economic zone
EFET	European Federation of Energy Traders
EFTA	European Free Trade Association
EHV	extra high voltage
EIA	environmental impact assessment
E-Mobility	electro-mobility
EMT	European target market
ENC	European Network Code
ENTSO	European Network of Transmission System Operators
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSO-G	European Network of Transmission System Operators for Gas
ENVI	Committee on Environment, Public Health and Food Safety
EPAD	electricity price area differentials
ERU	emission reduction unit
ESA	EFTA Surveillance Authority
ESMA	European Securities and Markets Authority

ESRB	European Systemic Risk Board
ETF	exchange transfer facility
ETIP	European Technology and Innovation Platform
ETS	emission trading system
ETSO	European Technical Standard Order
EU	European Union
EU DSO entity	European Entity for Distribution System Operators
EUA	EU emission allowance
EV	electric vehicle
FAME	fatty acid methyl ester
FEP	First Energy Package
FIP	feed-in premium
FIT	feed-in tariff
FLNG	floating liquefied natural gas
FOU	full ownership unbundling
FRSU	floating storage and regasification unit
FSB	Financial Stability Board
GCs	green certificates
GGPSSO	Guidelines for Good Third Party Access Practice for Storage System Operators
GHG	greenhouse gas
GIPL	Gas Interconnection Poland-Lithuania
GJ	gigajoules
GO	guarantee of origin
GTC	general terms and conditions
GTE	Gas Transmission Europe
GTF	gas transfer facility
HHI	Herfindahl-Hirschman Index
HPP	hydroelectric power plant
HV	high voltage
HVDC	high voltage direct current
IAEA	International Atomic Energy Agency

IC	interconnector
ICBC	Commercial Bank of China
ICE	internal combustion engine
ICO	income cap order
ICT	information and communication technology
IEM	internal energy market
IGA	intergovernmental agreement
ILUC	indirect land use change
IMF	International Monetary Fund
INDC	intended nationally determined contribution
INECP	integrated national energy and climate plan
INOGATE	Interstate Oil and Gas Transport to Europe
IP	interconnection point
IPS/UPS	integrated power system/unified power system
IRR	internal rate of return
ISDA	International Swaps and Derivatives Association
IT	information technology
ITO	independent transmission operator
ITO-plus	a model of the ITO, which is more independent
ITRE Committee	European Parliament's Committee on Industry, Research, Telecoms and Energy
JI	joint implementation
JOA	joint operating agreement
km	kilometres
LFR	low flux reactor
LNG	liquefied natural gas
LPG	liquefied petroleum gas
LSO	LNG system operator
M&A	mergers and acquisitions
MoU	memorandum of understanding
MRC	multi-regional coupling
MSR	market stability reserve

MSW	municipal solid waste
MTV	market trade value
MVT	motor vehicle tax
Nasdaq	Nasdaq Commodities Exchange
NBP	national balancing point
NC	network code
NC CACM	network code on capacity allocation and congestion management
NC CAM	network code on capacity allocation mechanisms in gas transmission systems
NC DCC	network code on demand connection code
NC EB	network code on electricity balancing
NC ER	network code on emergency and restoration
NC FCA	network code on forward capacity allocation
NC GBTN	network code on gas balancing of transmission networks
NC HVDC	network code on high-voltage-direct-current connections
NC IDER	network code on interoperability and data exchange rules
NC RfG	network code on grid connection applicable to all generators
NC SO	network code on system operation
NC TAR	network code on harmonised transmission tariff structures for gas
NEEAP	National Energy Efficiency Action Plan
NGO	non-governmental organisation
NPP	nuclear power plant
NRA	national regulatory authority
NREAP	National Renewable Energy Action Plan
NTC	net transfer capacity
OECD	Organisation for Economic Co-operation and Development
OJEU	Official Journal of the European Union
OTC	over-the-counter
OTF	organised trading facility
OWF	offshore wind farm
PCG	parent company guarantee
PCI	Project of Common Interest

PCR	price coupling of regions
PEMS	portable emissions measurement systems
PJ	petajoules
PPA	power purchase agreement
PSO	public service obligation
PST	phase shift transformer
PV	photovoltaic
R&I	research and innovation
RAV	regulatory asset value
RBP	regional booking platform
RDE	real driving emission
RDF	refuse derived fuel
REFIT	regulatory fitness programme
RERA	renewable energy resource areas
RES	renewable energy sources
RES-E	renewable energy sources for electricity
RES-T	renewable energy sources in transport
REU	renewable energy unit
RR	required revenue
RTS	regulatory technical standards
SEP	Second Energy Package
SET Plan	Strategic Energy Technology Plan
SETIS	Set Plan Information System
SFT	securities financing transaction
SMEs	small and medium-sized enterprises
SMP	system marginal price
SOLRs	supplier of last resort
SPV	special purpose vehicle
SRF	solid recovered fuel
SSO	storage system operator
TAL	Trans-Alpine-Pipeline

TANAP	Trans-Anatolian Natural Gas Pipeline
TAP	Trans-Adriatic Pipeline
TCMV	Technical Committee for Motor Vehicles
TEN-E	Trans-European Energy Network
TEN-T	Trans-European Transport Networks in Europe
TEP	Third Energy Package
TPA	third party access
TPP	thermal power plant
TSO	transmission system operator
TYNDP	European Ten-year Network Development Plan
UGSF	underground gas storage facility
UN	United Nations
VBP	virtual balance point
VIU	vertically integrated undertaking
VTP	virtual trading point
WACC	weighted average cost of capital
WEP	wholesale energy product

Overview of the legal and regulatory framework in 41 jurisdictions

This table has been collated using information compiled by the contributing authors for their corresponding jurisdictions and on the basis of information available at the time of writing.

ALBANIA

GENERAL	National regulatory authority (-ies)	Enti Rregullator i Energjisë Elektrike (Albanian Energy Regulator) ("ERE")
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Transmission System Operator ("TSO") is unbundled. Unbundling of the Distribution System Operator is provided in the law.
ELECTRICITY	Principal electricity generator(s)	Hydropower plants (public and private)
	Transmission system operator(s)	Operatori i Sistemit të Transmetimit (TSO)
	Electricity distributor(s)	Operatori i Sistemit të Shpërndarjes ("DSO")
	Principal electricity supplier(s)	Furnizuesi i Sherbimit Universal (Universal Service Supplier) ("FSHU")
	Interconnectors	• Greece: 400kV • Montenegro: 400kV • Montenegro: 220kV • Kosovo: 400kV • Kosovo: 220kV
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer
	Transportation system operator(s)	Albgaz
	Gas distributor(s)	Albgaz
	Principal gas supplier(s)	Kevin-Gaz SH.A. (joint stock company)
	Interconnectors	Trans-Adriatic Pipeline

AUSTRIA

GENERAL	National regulatory authority (-ies)	Energie-Control GmbH ("E-Control") Other authorities involved in the energy sector include: • Federal Competition Authority • Federal Cartel Prosecutor • Federal Ministry for Climate Protection, Environment, Energy, Mobility, Innovation and Technology
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Austria has opted to provide system operators with the option to choose between the FOU, ISO and ITO models, and the fourth, more independent, 'ITO plus' model. The electricity TSO, Austrian Power Grid ("APG"), and the gas TSOs, Gas Connect Austria ("GCA") and Trans Austria Gasleitung ("TAG"), are certified as ITOs.
ELECTRICITY	Principal electricity generator(s)	• Verbund • EVN • Wien Energie
	Transmission system operator(s)	• APG • Vorarlberger Übertragungsnetz (VÜN)
	Electricity distributor(s)	• Wiener Netz GmbH • Vorarlberger Energienetze GmbH • TINETZ-Stromnetz Tirol AG • Salzburg Netz GmbH • Netz Oberösterreich GmbH • Evn Netz GmbH • Steweag-steg GmbH • Bewag netz GmbH • KNG Kärnten Netz GmbH • Energie AG There are more than 130 other electricity distributors.
	Principal electricity supplier(s)	• Verbund • EVN AG • TIWAG • Wien Energie Vertrieb GmbH
	Interconnectors	Austria has interconnectors with the Czech Republic, Hungary, Italy, Germany, Slovenia and Switzerland.

AUSTRIA

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Austria produces natural gas domestically and also imports from: • Russia • Norway • Germany
Transportation system operator(s)	• GCA • TAG
Gas distributor(s)	• GCA • EVN Netz GmbH • Wiener Netze GmbH • Gasnetz Steiermarkt GmbH
Principal gas supplier(s)	• Verbund AG • EVN AG • Wien Energie GmbH
Interconnectors	Austria has seven gas interconnectors: • TAG • Mach Baumgarten Pipeline (MAB) • South-East Gas Pipeline (SOL) • West Austria Gas Pipeline (WAG) • Hungarian Austrian Gas Pipeline (HAG) • Penta West Pipeline (PW) • Kittsee Petrzalka Pipeline (KIP)

BELGIUM

GENERAL	National regulatory authority (-ies)	• CREG (Federal Regulator) • VREG (Flemish Regional Regulator) • BRUGEL (Brussels Capital Regional Regulator) • CWaPE (Walloon Regional Regulator)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY[1]	Principal electricity generator(s)[2]	Wholesale market shares of power generated (Total: 68.4TWh in 2020) • ENGIE Electrabel (50TWh (73%)) • EDF Luminus (7.9TWh (11%)) • T-Power (2.4TWh (4%)) • E.ON (0.1TWh (0%)) • Other energy companies with a combined market share of below 3% (8.0TWh (12%))
	Transmission system operator(s)	• Elia System Operator SA/NV; and • Elia Asset NL
	Electricity distributor(s)[3]	• Fluvius (Flanders) • Gaselwest (Flanders) • Imewo (Flanders) • Iverlek (Flanders) • Intergem (Flanders) • Iveka (Flanders) • PBE (Flanders) • Sibelga (Brussels Capital Region) • ORES (Wallonia) • Resa (Wallonia) • AIEG (Wallonia) • AIESH (Wallonia) • REW (Wallonia) • NETHYS (Wallonia) • SEDILEC (Wallonia)
	Principal electricity supplier(s)[4]	• ENGIE Electrabel (69.5% market share)

BELGIUM

ELECTRICITY[1] (continued)	Interconnectors	• France • Luxembourg • Germany • The Netherlands • United Kingdom
GAS[5]	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	All-natural gas is imported. Belgium's gas imports in 2020 were from: • Norway (48.5%) • The Netherlands (41%) • United Kingdom (2.4%) • Russia (LNG) (3.8%) • Qatar (LNG) (2.1%) • Other sources (2.2%) There is no shale gas in Belgium.
	Transportation system operator(s)	Fluxys
	Gas distributor(s)[6]	• Enexis (Flanders/The Netherlands) • Fluvius (Flanders) • Gaselwest (Flanders) • Imewo (Flanders) • INTER-ENERGA (Flanders) • Intergem (Flanders) • Iveka (Flanders) • Iverlek (Flanders) • Sibelga (Brussels Capital Region) • ORES (Wallonia) • RESA (Wallonia) • SEDILEC (Wallonia)
	Principal gas supplier(s)[7]	In 2020, 25 supply companies (shipping) were operating on the Belgian market. Ordered by market share these companies are: • ENGIE Electrabel (36%) • EDF Luminus (11%) • Total Gas & Power (10%) • Eni S.p.A. (9%) • Wingas (5%) • Others (less than 5%)
	Interconnectors	• United Kingdom

Endnotes

1. See www.creg.be/sites/default/files/assets/Publications/AnnualReports/2020/CREG-AR2020-EN.pdf, pp.15-50.
2. Ibid, p.40.
3. See www.synergrid.be/index.cfm?PageID=16823#
4. Ibid, pp.19-20.
5. See www.creg.be/sites/default/files/assets/Publications/AnnualReports/2020/CREG-AR2020-EN.pdf, pp. 51.
6. See www.synergrid.be/index.cfm?PageID=16823#.
7. See www.creg.be/sites/default/files/assets/Publications/AnnualReports/2020/CREG-AR2020-EN.pdf, p.63.

BULGARIA

GENERAL	National regulatory authority (-ies)	Minister of Energy Energy and Water Regulatory Commission
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	Kozloduy nuclear power plant (2,080MW) Thermal power plants: • AES Maritza East I (670MW) • Maritza East II (1,556MW) • Maritza East III (906MW)
	Transmission system operator(s)	Electricity System Operator EAD
	Electricity distributor(s)	• Electrorazpredelenie Iug EAD (EVN grid) • Electrodistribution networks West AD (Eurohold grid) • Electrorazpredelenie Sever AD (Energo-Pro grid) • ERP Golden Sands AD
	Principal electricity supplier(s)	• Electrohold Sales AD (Eurohold sales) • EVN Bulgaria Electrosnabdyavane EAD (EVN sales) • Energo-Pro Prodazhbi AD (Energo-Pro sales) • ESP Golden Sands OOD
	Interconnectors	Bulgaria has electricity interconnectors with the following countries: • Greece • North Macedonia • Romania • Serbia • Turkey

BULGARIA

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia. Due to a contractual dispute with Gazprom in 2022, Bulgaria imports supplies from the USA and Azerbaijan. Shale gas deposits are available; however, the development of shale gas projects is currently suspended due to a moratorium imposed by the Bulgarian Parliament in 2012.
	Transportation system operator(s)	Bulgartransgaz EAD ICGB AD
	Gas distributor(s)	Most of the local distribution companies are subsidiaries of Overgas AD
	Principal gas supplier(s)	Bulgargaz EAD
	Interconnectors	Bulgaria has gas interconnectors with the following countries: • Romania • Turkey • Greece • North Macedonia • Serbia

CROATIA

GENERAL	National regulatory authority (-ies)	The Croatian Energy Regulatory Agency (*Hrvatska energetska regulatorna agencija*) ("HERA").
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - ITO • Gas - FOU (unbundling certification is still pending)
ELECTRICITY	Principal electricity generator(s)	According to HERA's licence registry a total of 99 companies are licensed as electricity generators, among which the most important is HEP Proizvodnja d.o.o..
	Transmission system operator(s)	Hrvatski operator prijenosnog sustava d.o.o. ("HOPS").
	Electricity distributor(s)	HEP Operator distribucijskog sustava d.o.o. ("HEP-ODS").
	Principal electricity supplier(s)	• According to HERA's licence registry a total of 11 companies are licensed as electricity suppliers, among which the most significant are: • HEP-Opskrba d.o.o. • HEP-Elektra d.o.o. • GEN-I Zagreb d.o.o.
	Interconnectors	• Croatia, ie HEP, has cross border interconnections with all of its neighbours (Slovenia ("SI"), Serbia ("RS"), Bosnia and Herzegovina ("BA") and Hungary ("HU")) save Montenegro and Italy. These are, among others: • Tumbri - Krško (SI) • Melina - Divača (SI) • Pehlin - Divača (SI) • Ernestinovo - Pecs (HU) • Žerjavinec - Heviz (HU) • Mraclin - Prijedor (BA) • Međurić - Prijedor (BA) • Đakovo - Gradačac (BA) • Đakovo - Tuzla (BA) • Ernestinovo - Ugljevik (BA) • Ernestinovo - Sremska Mitrovica (RS) • Konjsko - Mostar (BA) • Zakučac - Mostar (BA) • Plat - Trebinje (BA).

CROATIA

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer (mainly from Russia). No shale gas. The company HEP d.d. acted as the wholesale gas supplier to other Croatian suppliers with public service obligations for the needs of household customers until 31 March 2021. As of 31 March 2021, the role of the wholesale gas market supplier was abolished.
Transportation system operator(s)	PLINACRO d.o.o..
Gas distributor(s)	• According to HERA's licence registry a total of 30 companies are licensed as gas distributors, among which the two most important are: • HEP-PLIN d.o.o.; and • GRADSKA PLINARA ZAGREB d.o.o..
Principal gas supplier(s)	• According to HERA's licence registry a total of 39 companies are licensed as gas suppliers, among which the most important are: • HEP d.d. (HEP-Opskrba plinom d.o.o., HEP-Trgovina d.o.o., HEP-PLIN d.o.o.) • PRVO PLINARSKO DRUŠTVO d.o.o. • INA d.d. • MET Croatia Energy Trade d.o.o. • E.ON Plin d.o.o. • MEĐIMURJE-PLIN d.o.o. • GPZ-Opskrba d.o.o.
Interconnectors	• Rogatec between Croatia and Slovenia (Plinovodi d.o.o.) • Drávaszerdahely between Croatia and Hungary (FGSZ Ltd) • LNG terminal (LNG Hrvatska d.o.o.) (as of 1 January 2021)

CYPRUS

GENERAL	National regulatory authority (-ies)	The Minister of Energy, Commerce and Industry, who has overall responsibility for energy matters and policy. The Cyprus Energy Regulatory Authority (CERA), an independent authority with regulatory competence over the electricity and gas markets.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	Diesel powerplants
	Transmission system operator(s)	CTSO
	Electricity distributor(s)	EAC-Distribution
	Principal electricity supplier(s)	EAC-Supply
	Interconnectors	None
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Neither. Cyprus' own gas discoveries have not been exploited yet. To date, plans for importing gas have not materialised.
	Transportation system operator(s)	N/A
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	None

CZECH

GENERAL	National regulatory authority (-ies)	Ministry of Trade and Industry, Energy Regulatory Office, and the State Energy Inspection.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	ČEZ Group (approx. 68% of electricity used in the Czech Republic)
	Transmission system operator(s)	ČEPS, a.s.
	Electricity distributor(s)	ČEZ Distribuce a.s., E.G.D, a.s., and PRE Distribuce, a.s.
	Principal electricity supplier(s)	ČEZ Prodej, a.s., E.ON Energie, a.s., innogy Energie, s.r.o., Pražská energetika, a.s.
	Interconnectors	SEPS (Slovakia), PSE (Poland), APG (Austria), TENNET and 50Hertz (Germany)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer, majority of gas coming from Russia. Minor shale gas sources. Shale gas extraction is not economically and ethically feasible.
	Transportation system operator(s)	NET4GAS, s.r.o.
	Gas distributor(s)	GasNet, s.r.o. (in the central and northern parts of the country), E.G.D, a.s. (in the south) and Pražská plynárenská, a.s. (in Prague).
	Principal gas supplier(s)	innogy Energie, s.r.o., ČEZ Prodej, a.s., Pražská plynárenská, a.s.
	Interconnectors	NET4GAS operates a transit pipeline with three international transfer stations; these are at Lanžhot, Brandov and Hora Sv. Kateřiny. There are also two international transfer stations, one at Cieszyn and one at Waidhaus, both of which are outside of Czech territory.

DENMARK

GENERAL	National regulatory authority (-ies)	The Ministry of Energy, Utilities and Climate Control, which has overall regulatory and supervisory responsibility. Danish Energy Agency, which is a central agency under the ministry and to which the tasks linked to energy production, supply and consumption have been delegated.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ISO
ELECTRICITY	Principal electricity generator(s)	Wind/central and decentralised powerplants
	Transmission system operator(s)	Energinet
	Electricity distributor(s)	Energinet
	Principal electricity supplier(s)	Andel Energi (formerly SEAS-NVE), Norlys, Vattenfall, NRGI and Energi Danmark
	Interconnectors	Eastern Denmark: three interconnectors (to Sweden/Germany) Western Denmark: four interconnectors (to Norway, Germany, Netherlands & Sweden)
GENERAL	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Currently importer country (via Germany – mainly of Russian origin)
	Transportation system operator(s)	Energinet.dk
	Gas distributor(s)	Energinet.dk
	Principal gas supplier(s)	Energinet, HOFOR A/S, OK, Total Energies A/S, Ineos, Evida, Gas Storage Denmark A/S, Dansk Offshore (trade association)
	Interconnectors	One import/export connector to Germany (via Ellund) One export connector to Sweden (via Dragør)

ESTONIA

GENERAL	National regulatory authority (-ies)	Estonian Competition Authority
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU for electricity and gas
ELECTRICITY	Principal electricity generator(s)	Eesti Energia group
	Transmission system operator(s)	Elering
	Electricity distributor(s)	In total there are 33 electricity distributors. Elektrilevi, a subsidiary of the largest electricity supplier Eesti Energia, has the largest market share (approximately 86%).
	Principal electricity supplier(s)	In total there are 25 electricity suppliers active in the retail sales market. Eesti Energia has the largest market share (approximately 61%), followed by Elektrum Eesti (approximately 11%) and Scener (approximately 8%).
	Interconnectors	Connected with Finland, Latvia and Russia: • two interconnectors with total capacity of 1,000MW with Finland • three interconnectors with total capacity of 1,500MW with Latvia, including the latest interconnector with total capacity of 600MW becoming operational in 2021 • three interconnectors with total capacity of 650MW with Russia Synchronously interconnected with IPS/UPS.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Estonia imports natural gas from Russia. Approximately 84% of gas imports originate from Russia (directly, or via Latvia or Finland). Additionally, LNG is being imported from Finland, Lithuania, Poland and Russia. There is no shale gas.
	Transportation system operator(s)	Elering
	Gas distributor(s)	In total there are 23 gas distributors. Gaasivõrk, subsidiary of the largest gas importer and gas supplier Eesti Gaas, has the largest market share (approximately 82%).
	Principal gas supplier(s)	In total there are 31 gas suppliers active in the retail sales market. Eesti Gaas has the largest market share (75%).
	Interconnectors	Historically Estonia only had interconnectors with Latvia and Russia, and as of 2020 also has an interconnector with Finland.

FINLAND

GENERAL	National regulatory authority (-ies)	The national supervisory authority for electricity and gas markets is the Energy Authority (before 1 February 2014, the "Energy Market Authority"). In addition to the Energy Authority, the electricity and gas markets are overseen by the Finnish Competition and Consumer Authority and the Finnish environmental authorities.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Electricity: The Electricity Market Act requires legal and operational unbundling for both the transmission system operator ("TSO") and large and mid-size distribution system operators ("DSOs"). Unbundling through separate accounts is sufficient for small DSOs that have distributed less than 200GWh annually through their 400V network during the previous three calendar years. FOU applies to the TSO. Gas: On 1 January 2020, the natural gas market opened for competition in Finland due to Natural Gas Market legislation entering into force. Prior to 2020, there were no legal requirements in place regarding unbundling. Currently, there are no legal or operative unbundling requirements to fulfill, since Finland has decided that the provisions regarding unbundling are not applied to DSOs with less than 100,000 customers. All Finnish gas DSOs currently fall under this limit. Accounting unbundling is required from all DSOs. FOU applies to the TSO.
ELECTRICITY	Principal electricity generator(s)	• Fortum Oyj • Pohjolan Voima Oy • the forest industry
	Transmission system operator(s)	Fingrid Oyj
	Electricity distributor(s)	There are about 80 distribution network companies in Finland, the majority of which are owned or controlled by municipalities. The largest DSO in Finland, Caruna Oy, has about 714,000 customers. The 15 largest DSOs in Finland cover over 70% of the electricity distribution network, network users and revenue.
	Principal electricity supplier(s)	The Finnish electricity generation sector is characterized by a large number of actors. There are about 58 electricity suppliers in Finland and about 400 power plants, the majority of which are hydropower plants. The share of the three biggest generating companies of the total installed capacity is about 40%.
	Interconnectors	There are interconnectors between Finland and: • Sweden • Norway • Estonia • Russia Additionally, Finland's main grid is a part of the inter-Nordic synchronous system, which includes the transmission grids of Finland, Sweden, Norway and eastern Denmark.

FINLAND

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Baltic States by Balticconnector. Since May 2022, Russia has suspended gas imports to Finland. There are no known shale gas deposits in Finland.
Transportation system operator(s)	Gasgrid Finland Oy, a company fully owned by the State of Finland.
Gas distributor(s)	The distribution of natural gas to private households and other minor consumers is not significant in Finland. There are 18 natural gas DSOs. Most of the DSOs are owned by municipalities with a few owned by industrial users of natural gas.
Principal gas supplier(s)	Over 90% of the gas consumed in Finland is transmitted directly by Gasum Oy to end users, which are mainly industrial operators and energy and power companies. The retail sale of natural gas accounts for 7% of total consumption. Natural gas operations such as transmission activities may be carried out subject to a licence granted by the Finnish Energy Authority. However, the mere selling of natural gas does not require a licence but is subject to certain statutory requirements.
Interconnectors	All the gas that Finland consumes is currently being imported from the Baltic states through Balticconnector, ie a submarine interconnector between Finland and Estonia. There are also two parallel pipelines between Finland and Russia, both operated by Gasgrid Finland Oy. The pipelines are currently not importing gas as from May 2022, Russia suspended gas imports to Finland.

FRANCE

GENERAL	National regulatory authority (-ies)	• Ministry of Energy • Commission de régulation de l'énergie (CRE)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• FOU model (for Terega - gas transmission network operator, former TIGF) • ITO model (for other operators)
ELECTRICITY	Principal electricity generator(s)	• ENGIE • Electricité De France (EDF) • Compagnie Nationale du Rhône (CNR) • Uniper • Total Energies
	Transmission system operator(s)	Réseau de transport d'électricité (RTE)
	Electricity distributor(s)	ENEDIS and between approximately 120 and 160 local distributors (*Entreprises Locales de Distribution*)
	Principal electricity supplier(s)	The Finnish electricity generation sector is characterized by a large number of actors. There are about 58 electricity suppliers in Finland and about 400 power plants, the majority of which are hydropower plants. The share of the three biggest generating companies of the total installed capacity is about 40%.
	Interconnectors	List of suppliers having concluded an agreement with ENEDIS (update on 1 February 2023): • ACTELIOS SOLUTIONS (JPME) • AKUO MARKET FRANCE • ALLEGO FRANCE • ALPIQ ENERGIE FRANCE • ALPIQ RETAIL FRANCE • ALPIQ SOLUTIONS FRANCE • ALSEN • ALTERNA • ANTARGAZ • AUCHAN ENERGIES • AXPO FRANCE • AXPO SOLUTIONS AG • BCM ENERGY • CHINA POWER FRANCE • COMPAGNIE NATIONALE DU RHONE (CNR) • DREAM ENERGY

ELECTRICITY (continued)

FRANCE

- DYNAMO
- DYNEFF
- e - PANGO
- EBM COOPERATIVE ELEKTRA BIRSECK
- EDSB L'AGENCE
- EKWATEUR
- EKWATEUR PRO
- ELECOCITE
- ELECTRICITÉ DE FRANCE (EDF)
- ELECTRICITÉ DE SAVOIE
- ELENEO
- elmy Fourniture
- ELSAN
- ENALP
- ENARGIA
- ENDESA ENERGIA SA
- ENERCOOP
- ENERGEM
- ENERGIES DU SANTERRE
- ENGIE
- ENI GAS & POWER FRANCE
- ENOVOS ENERGIE
- ENOVOS LUXEMBOURG
- ENRGIA ENERGIE CATALANE
- ES ÉNERGIES STRASBOURG
- FLASH
- GAZ DE BORDEAUX
- GAZEL ENERGIE SOLUTIONS
- GAZENA
- GEDIA ÉNERGIES & SERVICES
- GEG SOURCE D'ÉNERGIES
- GREEN NETWORK ENERGIE
- GREEN YELLOW ENERGIE PRO
- GREEN YELLOW ENERGY SUPPLY & SERVICES France
- GROUPE BUTAGAZ - GAZ DE PARIS – GAZ EUROPEEN
- HELLIO SOLUTIONS
- HYDRONEXT
- IBERDROLA CLIENTES
- IBERDROLA ENERGIE FRANCE
- ILEK
- INNOVENT
- La bellenergie
- LUCIA

ELECTRICITY (continued)

	• MEGA ENERGIE • MINT • NEXTEARTH • NLG (URBAN SOLAR ENERGY) • OHM ENERGIE • OMEGA SAS (ENERGIES & SERVICES) • OPERA ENERGIE • OVO ENERGY • PAPERNEST ENERGY • PICOTY • PLÜM ENERGIE – XELAN • PLÜM ENERGIE PRO • PRIMEO ENERGIE FRANCE • PRIMEO ENERGIE GRANDS COMPTES • PRIMEO ENERGIE SOLUTIONS • PROXELIA • R ENERGIE • SAGITERRE • SAVE (Société d'Approvisionnement et de Vente d'Energies) • SAVE ENERGIES VERTES • SELFEE • SELIA • SOCIETE D'IMPORTATION LECLERC (SIPLEC) • SOLVAY ENERGY SERVICES • SONEPP (Société de Négoce de Produits Pétroliers) • SOWEE • SYNELVA • TotalEnergies Electricité et Gaz France • UNION DES PRODUCTEURS LOCAUX D'ELECTRICITE (UPLE) - ENERGIE D'ICI • VALORIS ENERGIE • VATTENFALL ENERGIES • VATTENFALL EUROPE SALES • VOLTERRES • WEKIWI
Interconnectors	• Switzerland • Italy • Great Britain • Spain • Germany • Belgium • Ireland (under development)

FRANCE

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer (importation notably from Norway, The Netherlands, Algeria, Nigeria, Egypt and Qatar – importation from Russia was suspended in September 2022). Shale gas exploration and production is prevented via the prohibition of hydraulic fracturing techniques.
Transportation system operator(s)	• GRTgaz • Teréga
Gas distributor(s)	GRDF and approximately 25 local distributors (*Entreprises Locales de Distribution*)
Principal gas supplier(s)	• Alpiq • Antargaz naturel • Alterna • Antargaz • Axpo • Breizh Gaz • Butagaz • Dyneff gaz • EDF • Edia • ekWateur • Endesa Energia • énergem • Energies du Santerre • ENGIE • Eni • ES • Gaz Europeen • Gazprom Energy • Engie Gaz Tarif Réglementé • Enovos • Gaz de Bordeaux • Gazel Energie • Gedia Energies-Services • GEG Source d'Energies • Happ • Naturgy • Iberdrola • MEGA Energie • Mint Energie • NatGAS France • Ohm Energie • PICOTY • Primeo Energie

GAS (continued)		• SAVE • Séolis • SELIA • Solvay Energy Services • Total Energie • Vattenfall
	Interconnectors	• Norway • Belgium • Germany • Switzerland • Spain

GERMANY

GENERAL	National regulatory authority (-ies)	Federal Network Agency (*Bundesnetzagentur*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	All three unbundling options are provided by the EnWG (*Energiewirtschaftsgesetz*)
ELECTRICITY	Principal electricity generator(s)	Uniper, RWE, Vattenfall, LEAG and EnBW
	Transmission system operator(s)	Amprion GmbH, TenneT GmbH, Transnet GMBH and 50Hertz Transmission GmbH
	Electricity distributor(s)	Several (RWE, EnBW, E.ON, Vattenfall, EWE, RheinEnergie)
	Principal electricity supplier(s)	Several (RWE, EnBW, E.ON, Vattenfall, EWE, RheinEnergie)
	Interconnectors	Austria, Switzerland, France, Luxembourg, Belgium, the Netherlands, Denmark, Poland and the Czech Republic (a new interconnector between Germany and the UK is due to be completed in 2025)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer country: Norway, Belgium, Netherlands
	Transportation system operator(s)	Several TSOs (Gascade, GTG Nord, Gasunie Deutschland, Nowega, Ontras, Fluxys, GRTgaz, OGE, terranets bw, bayerners)
	Gas distributor(s)	E.ON/Uniper, RWE, VNG, Wingas BEB
	Principal gas supplier(s)	E.ON/Uniper, RWE, VNG, Wingas BEB
	Interconnectors	Denmark, Poland, Czech Republic

GREECE

GENERAL	National regulatory authority (-ies)	Regulatory Authority for Energy (RAE)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity: FOU • Gas: FOU
ELECTRICITY	Principal electricity generator(s)	• Public Power Corporation ("PPC") • Heron Thermoilektriki I • Heron II Viotia • Protergia • Elpedison • Korinthos Power
	Transmission system operator(s)	IPTO (Independent Power Transmission Operator) (ADMIE)
	Electricity distributor(s)	HEDNO (Hellenic Distribution Network Operator) (DEDDIE)
	Principal electricity supplier(s)	• PPC • Heron Thermoilektriki • Protergia • Elpedison • Watt & Volt • NRG • Volterra • Green • KEN
	Interconnectors	Greece has electricity interconnectors with: • Albania • North Macedonia • Bulgaria • Turkey • Italy

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer of piped gas from Russia and Turkey and liquefied natural gas (LNG) from Algeria and other destinations. Greece is not engaged in shale gas extraction.
	Transportation system operator(s)	National Natural Gas Transmission System Operator (the NNGTS Operator) (DESFA)
	Gas distributor(s)	• Attica Gas Distribution Company • Thessaloniki & Thessalia Gas Distribution Company • Public Gas Distribution Company • HENGAS
	Principal gas supplier(s)	• Public Gas Company (DEPA) • MNG TradingAttica Gas Supply Company • Thessaloniki-Thessalia Gas Supply Company (Zenith) • PPC
	Interconnectors	Greece has gas interconnectors with: • Turkey • Bulgaria

HUNGARY

GENERAL	National regulatory authority (-ies)	Hungarian Energy and Public Utility Regulatory Authority ("HEA") Further involved authorities include: • Ministry of Technology and Industry • Supervisory Authority for Regulated Services
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	As decided by the Hungarian legislator, the ITO model was introduced for MAVIR (the electricity Transmission System Operator ("TSO")) and FGSZ (the gas TSO).
ELECTRICITY	Principal electricity generator(s)	• MVM Group • MET Group • E.ON Group
	Transmission system operator(s)	MAVIR
	Electricity distributor(s)	• MVM Émász Áramhálózati Kft. • MVM Démász Áramhálózati Kft. • OPUS TITÁSZ Áramhálózati Zrt. • E.ON Dél-dunántúli Áramhálózati Zrt. • E.ON Észak-dunántúli Áramhálózati Zrt. • ELMŰ Hálózati Kft.
	Principal electricity supplier(s)	• MVM • E.ON • CEZ • Alpiq • ELMŰ-ÉMÁSZ • MET

ELECTRICITY (continued)	Interconnectors	The cross-border interconnectors are: • Göd – Levice (Slovakia) (400kV) • Győr – Gabčikovo (Slovakia) (400kV) • Sajóivánka – Rimaszombat (Slovakia) (400kV) • Gönyű – Nagygyőröd (Slovakia) (400kV) • Albertirsa – Zakhidnoukrainska (Ukraine) (750kV) • Kisvárda – Mukačevo (Ukraine) (220kV) • Sajószöged – Mukačevo (Ukraine) (400kV) • Tiszalök – Mukačevo (Ukraine) (220kV) • Békéscsaba – Nadab (Romania) (400kV) • Sándorfalva – Arad (Romania) (400kV) • Hévíz – Zerjavinec (Croatia) (400kV) • Paks – Ernestinovo (Croatia) (400kV) • Sándorfalva – Subotica (Serbia) (400kV) • Győr – Wien Südost (Austria) (400kV) • Győr – Neusiedl (Austria) (220kV) • Győr – Wien Südost (Austria) (220kV)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Domestic production of natural gas covers only a minor part of national consumption. Importer, primarily from Russia.
	Transportation system operator(s)	FGSZ
	Gas distributor(s)	• E.ON Dél-dunántúli Gázhálózati Zrt. • E.ON Közép-dunántúli Gázhálózati Zrt. • MVM Égáz-Dégáz Földgázhálózati Zrt. • MVM Főgáz Földgázhálózati Kft. • OPUS TIGÁZ Gázhálózati Zrt.

HUNGARY

GAS (continued)

Principal gas supplier(s)	• MVM • E.ON • MET • E2
Interconnectors	The cross-border interconnectors and relevant TSOs are: • Beregdaróc/Ukrtansgas (Ukraine) • Mosonmagyaróvár/OMV Gas (Austria) • Kiskundorozsma/Srbijagas (Serbia) • Kiskundorozsma 2/Srbijagas (Serbia) • Csanádpalota/Transgaz (Romania) • Drávaszerdahely/Plinacro (Croatia) • Balassagyarmat/Eustream (Slovakia)

ICELAND

GENERAL	National regulatory authority (-ies)	National energy authority (ORKUSTOFNUN)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Hybrid of ITO and FOU
ELECTRICITY	Principal electricity generator(s)	• Landsvirkjun • ON Power • HS Orka • Orkusalan • Fallorka • Westfjord Power Company
	Transmission system operator(s)	Landsnet
	Electricity distributor(s)	• Reykjavik Energy (Veitur) • RARIK • HS Veitur • Westfjord Power Company • Norðurorka • Rafveita Reydarfjarðar
	Principal electricity supplier(s)	• Orka náttúrunnar (ON Power) • HS Orka • Orkusalan • Fallorka • Orkubú Vestfjarða (Westfjord Power Company)
	Interconnectors	N/A - there are no interconnectors
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	N/A
	Transportation system operator(s)	N/A
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	N/A

IRELAND

GENERAL	National regulatory authority (-ies)	Commission for Regulation of Utilities ("CRU")
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – ISO • Gas - ITO
ELECTRICITY	Principal electricity generator(s)	• ESB • Energia • SSE Airtricity • Bord Gáis Energy
ELECTRICITY	Transmission system operator(s)	• EirGrid
ELECTRICITY	Electricity distributor(s)	ESB Networks Limited
ELECTRICITY	Principal electricity supplier(s)	• Electric Ireland (ESB) • SSE Airtricity • Bord Gáis Energy • Flogas, Energy for Enterprise
ELECTRICITY	Interconnectors	• 500MW East-West interconnector between Ireland and Wales, owned by EirGrid • 500MW HVDC Moyle interconnector between Northern Ireland and Scotland, owned by Mutual Energy The transmission system between Ireland and Northern Ireland is operated as a single meshed network.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Domestic production and imports gas from the UK. There is currently no shale gas in the jurisdiction.
GAS	Transportation system operator(s)	Owned and operated by Gas Networks Ireland, a wholly owned subsidiary of the semi-state company Ervia
GAS	Gas distributor(s)	Gas Networks Ireland
GAS	Principal gas supplier(s)	• Electric Ireland (ESB) • SSE Airtricity • Bord Gáis Energy • Flogas, Energy for Enterprise
GAS	Interconnectors	• Two subsea interconnectors between Ireland and Scotland. • South-North pipeline, which connects Ireland and Northern Ireland.

ISRAEL

GENERAL	National regulatory authority (-ies)	• Ministry of Energy • Natural Gas Authority • Electricity Authority • Ministry of Environmental Protection • Competition Authority (formerly known as the Antitrust Authority)
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	As part of the reform of the Israel Electric Corporation (IEC), as of 1 November 2021, the System Operator activities have been transferred completely from IEC to a separate Government-owned company called Noga – Israel Independent System Operator Ltd.
ELECTRICITY	Principal electricity generator(s)	• Israel Electric Corporation (state-owned) • OPC Rotem, Limited • Dalia Power Energies, Limited • Dorad Energy, Limited • Ramat Hovav Power Plant, Limited Partnership • MRC Alon Tavor Power Ltd • I.P.M. Beer Tuvia Ltd • Negev Energy Ashalim Thermo-solar • P.S.P Investments Ltd • Megalim Solar Energy Ltd
ELECTRICITY	Transmission system operator(s)	Israel Electric Corporation (state-owned)
ELECTRICITY	Electricity distributor(s)	Israel Electric Corporation (state-owned)
ELECTRICITY	Principal electricity supplier(s)	• Israel Electric Corporation (state-owned) • OPC Rotem, Ltd./OPC Hadera Ltd. • Dalia Power Energies, Limited • Dorad Energy, Limited • I.P.M Beer Tuvia Ltd • I.P.P. Alon Tavor Ltd • I.P.P. Ramat Gavriel Ltd
ELECTRICITY	Interconnectors	None currently.

ISRAEL

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer of liquefied natural gas (LNG) through FSRU. Exporter of natural gas from Tamar field to Jordan since 2017. Exporter of natural gas from Leviathan field to Egypt and Jordan since January 2020, and from Tamar field to Egypt since July 2020. There is no shale gas in Israel.
	Transportation system operator(s)	Israel Natural Gas Lines Limited
	Gas distributor(s)	• Natural Gas South, Limited • Negev Natural Gas, Limited • SuperNG Natural Gas Distribution Company, Limited • Merimon Natural Gas North, Limited • SuperNG Hadera and the Valleys Natural Gas Distribution Company, Limited • Rotem Natural Gas, Limited
	Principal gas supplier(s)	The Tamar leaseholders (online since 2013) • Chevron Mediterranean, Limited • Tamar Investment 1 RSC, Limited and Tamar Investment 2 RSC, Limited • Isramco Negev 2, Limited Partnership • Dor Gas Exploration, Limited Partnership • Tamar Petroleum, Limited • Everest Infrastructures, Limited Partnership The Leviathan leaseholders (online since 2020) • NewMed Energy, Limited Partnership • Chevron Mediterranean, Limited • Ratio Oil Exploration (1992), Limited Partnership (formerly known as Delek Drilling Energean Israel, Limited (Gas supply is expected by the end of Q3 2022)
	Interconnectors	• Israel – Jordan: One pipeline for transporting gas from Israel to Jordan (in the Dead Sea area) has been active since 2017. An additional pipeline for transporting gas to Jordan from the Leviathan gas reservoir through Israel's national transmission system has been active since 1 January 2020. • Israel – Egypt: A pipeline for transporting gas to Egypt (based on an old gas pipeline for transportation of gas from Egypt to Israel) became active on 15 January 2020. • There are also plans to construct a joint cross-border interconnector, the EastMed pipeline (an EU Project of Common Interest), from Israel to Greece via Cyprus and thereafter to Italy and other Southern European countries.

ITALY

GENERAL	National regulatory authority (-ies)	• Ministry of Economic Development • Ministry of Ecological Transition • ARERA (*Autorità di Regolazione per Energia, Reti e Ambiente*) • AGCM, the antitrust authority (*Autorità Garante della Concorrenza e del Mercato*) • CSEA, the Treasury for Energy and Environment Services (*Cassa per i servizi energetici e ambientali*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – FOU (Terna S.p.A.) • Gas – FOU (Snam Rete Gas S.p.A.)
ELECTRICITY	Principal electricity generator(s)	• ENEL: 20.5% • ENI: 9.6% • EDISON: 7.6% • A2A: 6.3% • EPH: 5.5% • Iren: 3.1% • Engie: 2.7% • Tirreno Power: 2.4% • Sorgenia: 2.2% • Erg: 2.0% • Axpo Group: 2.0% • Saras: 1.6% • Lukoil: 1.2% • Alperia: 1.0% Remaining generators with each less than 1% of the volume of electricity generated: 32.3%
	Transmission system operator(s)	Terna S.p.A.
	Electricity distributor(s)	• Enel Distribuzione: 86.8% • Acea Distribuzione: 4.5% • A2A Reti Elettriche: 3.1% • Iren: 1.9% Remaining distributors with each less than 1% of the volume of electricity distributed: 3.7%

ITALY

ELECTRICITY (continued)	Principal electricity supplier(s)	• ENEL Group: 21.1% • EDISON Group: 6.1% • ENI Group: 5.5% • AXPO Group: 4% • GALA Group: 3.4%
	Interconnectors	About 11.8% of Italy's electricity is imported via interconnection lines along the northern border. 22 cross-border interconnection lines are currently in operation with Switzerland, Austria, France, Slovenia and Greece.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	About 92.7% of gas consumed in Italy is imported from abroad, mainly from the following countries: • Russia: about 41.1% • Algeria: about 29.6% • the Netherlands, Norway and Northern Europe: about 13% • Qatar: about 8.4% • Libya: about 7.3%
	Transportation system operator(s)	• Snam Rete Gas S.p.A. • Società Gasdotti Italia S.p.A. • Infrastrutture Trasporto Gas S.p.A. (formerly Edison Stoccaggio)
	Gas distributor(s)	• Snam S.p.A.: 23.8% • 2i Reti Italia S.p.A.: 17.2% • Hera S.p.A.: 9.5% • A2A Group: 5.9% • Iren S.p.A.: 4.1% • Several municipally owned and minor private companies
	Principal gas supplier(s)	• Eni S.p.A.: 20.7% • Edison S.p.A.: 13.3% • Enel S.p.A.: 11.0% • EPH: 4.2% • Iren Mercato S.p.A.: 4.2% • Hera Comm S.p.A.: 3.6% • A2A S.p.A.: 3.3% • Sorgenia S.p.A.: 2.0%

GAS (continued)

Interconnectors	The following five entry points currently connect the Italian grid to gas cross-border interconnection (currently operated and managed by Snam Rete Gas S.p.A.) by way of five pipelines and three liquefied natural gas (LNG) regasification terminals: • Mazara del Vallo, Sicily • Tarvisio, Friuli Venezia Giulia • Passo Gries, Lombardy • Gela, Sicily • Gorizia, Friuli Venezia Giulia • Panigaglia, Liguria • Carvazere, Veneto • Livorno, Toscana

KAZAKHSTAN

GENERAL	National regulatory authority (-ies)	Ministry of Energy
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	Electricity in Kazakhstan is generated by 179 power plants of various forms of ownership. As of 1 January 2021, the total installed capacity of the power plants is 23,621.6MW, with an available capacity of 20,078.6MW.[1] Samruk-Energy JSC, owned by the Kazakhstan State, and its group of companies[2] are major power generating organisations ("PGOs"). There are also privately-owned PGOs. The major power plants may be grouped as follows:[3] 1) The power plants of national importance (the large thermal power plants generating and selling electricity to consumers at the electricity wholesale market of Kazakhstan): • Ekibastuz GRES-1 LLP • Ekibastuz Station GRES-2 JSC • Thermal power plant ("TPP") of Eurasian Energy Corporation JSC (Aksu TPP) • GRES Topar of Kazakhmys Energy LLP • Jambylskaya GRES JSC 2) Large hydro power plants (used as auxiliary units and for regulating the load of the unified power system of Kazakhstan): • Bukhtarminskiy Hydro Power Complex of Kazzinc LLP • AES Ust-Kamenogorsk HPP LLP • AES Shulbinsk HPP LLP 3) The power plants of industrial importance (which include TPPs) with a combined production of electric and thermal energy, which serve for electricity and heat supply of large industrial enterprises and nearby settlements): • CHPP-3 of Karaganda Energocenter LLP • CHPP-PVS, CHPP-2 of Arcelor Mittal Temirtau JSC • Rudnenskaya TPP of Sokolovsko-Sarbaiskoye Mining and Processing Enterprise JSC • Balkhash TPP of Kazakhmys Corporation LLP • Zhezkazgan TPP of Kazakhmys Corporation LLP • Pavlodar TPP-1 of Aluminium of Kazakhstan JSC • Shymkent TPP-1, TPP-2

Transmission system operator(s)	A joint stock company, the Kazakhstan Electricity Grid Operating Company (or JSC "KEGOC") is the system operator of the unified power system of Kazakhstan.[4]
Electricity distributor(s)	Electric networks in Kazakhstan include substations from 0.4Kv to 1,150kV, switchgears and electricity transmission lines connecting them to transmit and distribute electricity. The backbone grid in Kazakhstan's united power system is the National Power Grid ("NPG"), providing connections between the regions of the country and with the power systems of neighbouring countries (the Russian Federation, the Kyrgyz Republic and the Republic of Uzbekistan) and delivers electricity from the power plants to wholesale consumers. KEGOC owns 220kV and above substations, switchgears, interregional and interstate transmission lines being a part of the NPG including lines used for connection of power plants. Regional power networks provide electrical connections within regions and power transmission to retail consumers. Electric networks of a regional level belong to and are operated by regional energy companies ("RECs"), including, among others: • Alatau Zharyk Company JSC and AlmatyEnergoSbyt LLP (owned by Samruk-Energy JSC) • CAEPCO (Central-Asian Electric Power Corporation), including its subsidiaries Astanaenergosbyt LLP, Akmola Electricity Distribution Company JSC, Pavlodarenergo JSC (and its Pavlodar Regional Electric Distribution Company JSC), Sevkazenergo JSC (and its North-Kazakhstan Regional Electric Distribution Company JSC and Sevkazenergosbyt Atyrau Zharyk JSC • Batys Transit JSC • JSC Mangistau Regional lectric Grid Company JSC • Mangistauenergomunai LLP • Energosystema LLP • JSC North-Kazakhstan REC • Kokshetau Energo LLP • East Kazakhstan Regional Energy Company JSC • Kostanay Energocenter LLP • Mezhregionenergotranzit LLP • JSC Kyzylordinskaya REC (JSC KREC) • Kazakhstan Karagandy Zharyk LLP and Ontustik Zharyk Tranzit LLP (owned by Kazakhstan Utility Systems LLP) The power transmission companies provide contract-based electricity transmission services using their own or managed (rent, lease, trust management and other types of use) electric networks for the wholesale and retail consumers or power supplying companies.

KAZAKHSTAN

ELECTRICITY (CONTINUED)

Principal electricity supplier(s)	Distribution of electricity through 0.4kV to 220kV electric networks in Kazakhstan is carried out by 21 RECs and more than 109 other small energy transmission organisations. A list of major regional supplies includes:[5] • Astanaenergosbyt LLP (for Astana) • Kokshetau Energo Center LLP, AREC-Energosbyt LLP (or Akmola Electricity Distribution Company-Energosbyt LLP), Stepnogorsk Energosbyt LLP, Shantobe-energocomplex LLP (for the Akmolinskaya oblast) • AlmatyEnergoSbyt LLP (owned by Samruk-Energy JSC) (for Almaty) • Zhetysu Energotrade LLP (for the Almaty oblast) • AtyrauEnergoStu LLP (for the Atyrau oblast) • Mangistau Regional Electric Grid Company JSC and SCE Ozenenergoservice LLP (for the Mangistauskaya oblast) • Aktobeenergosnab LLP (for the Aktobe oblast) • Batys Energoresursy LLP (for the West-Kazakhstan oblast) • Sevkazenergosbyt LLP and Soltustik Energo Ortalyk LLP (for the North-Kazakhstan oblast) • Sygysenergotrade LLP (for the East-Kazakhstan oblast) • Pavlodarenergosbyt LLP and Ekibastuzenergo LLP (for the Pavlodar oblast) • CSE Kostanaiyuzhelectroservice, SCE KUN, RudnenskayaEnergoCompany LLP, SCE Zhitikaracommunenergo, SCE Kostanaiskiy EnergoCenter, SCE PCO Lissakovskgorcommunenergo (for the Kostanay oblast) • KaragandyZhyluSbyt LLP, Okzhetpes LLP, Rasschetniy Servisniy Center LLP, Energougol XXI LLP, Electrzhabdyktau LLP, Zhezkazgan energosbyt LLP, Kazenergocenter LLP (for the Karaganda oblast) • Dauletenergo LLP, Shieli zharygy LLP, Energoservice LLP (for the Kyzylorda oblast) • ZhambylZharykSauda-2030 LLP (for the Zhambyl oblast) • Energopotok LLP (for Shymkent and the Turkestan oblast)
Interconnectors	KEGOC, as the system operator, is responsible for interacting with the power systems of neighbouring countries to manage and ensure the stability of parallel operation modes and electric power regulation.[6]

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Exporter country. Major fields: Karachaganak, Tengiz, Kashagan, Uzen, Zhanazhol, Zhetybay, Aktota, Kalamkas, Kalamkas-teniz, Kayran, Amangeldy, Urikhtau, Imashevskoye, Prorva Zapadnaya, Chinarevskoye, Rozhkovskoye, Shagyrly-Shamyshty, Tenge and other fields on the List of Strategic Deposits.[7] Major producers: Tengizchevroil LLP, Karachaganak Petroleum Operating BV, PetroKazakhstan JSC, CNPC-Aktobemunaigas JSC, Mangistaumunaigas JSC, Amangeldy Gas LLP (which is a subsidiary of QazaqGaz JSC). According to some estimates,[8] Kazakhstan contains 253Tcf of dry, wet and associated shale gas in-place, with 27Tcf as the risked, technically recoverable shale gas resource. Considering that Kazakhstan produces natural oil and gas and there has been no major developments relating to the production of shale oil and gas, it is unlikely that there are reserves of shale oil and shale gas.

GAS (CONTINUED)

Transportation system operator(s)	QazaqGaz JSC, the national gas transportation company owned by the state-owned national company KazMunaiGas JSC,[9] and its subsidiaries: JSC Intergas Central Asia (ICA),[10] Asia Gas Pipeline LLP[11] (a project company, managing construction and operation of the Kazakhstan-China Gas Pipeline), KazRosGas LLP,[12] Beineu-Shymkent Gas Pipeline LLP[13] and JSC QazaqGaz Aimak[14]
Gas distributor(s)	Regional gas distribution (and supplying) companies:[15] • JSC QazaqGaz Aimak • JSC QazaqGaz-Almaty • JS JSC Aktaugasservice • Atyraugasinvest LLP • Atyrauoblgas LLP • Zhetysu gas montazh LLP • Zhylyoigas LLP • Tauekel gas kubyry LLP • Tauekel-N-Algabas • Tauekel-T LLP • Turangas-7 LLP • KBS Gaz LLP • Central Gas Supply of Astana LLP (TOO 'Tsentralnoye Gazosnabzheniye of Astana')
Principal gas supplier(s)	Regional gas supplying (and distribution) companies:[16] • Intergas Central Asia JSC • Beineu-Shymkent Gas Pipeline LLP • KTG Finance B.V. • Qazaq Gas Qurylys LLP • QazaqGas-Bishkek LLC • QazaqGas-Onimderi LLP • Auto Gas Almaty LLP • QazaqGas Aimak JSC • Amangeldy Gas LLP • KazRosGas LLP • Otan Gas LLP • KazMunayGas – Service NS JSC • Asian Gas Pipeline LLP • Asian Gas Pipeline – Horgos • PVH Development LLP
Interconnectors	QazaqGaz JSC and its subsidiaries (or joint ventures with its participation) are primarily responsible for inter-connectors.

Endnotes

1. See www.kegoc.kz/en/electric-power/elektroenergetika-kazakhstana.
2. For information regarding Samruk-Energy JSC and its group of companies, see: www.samruk-energy.kz/en.
3. See www.kegoc.kz/en/power-industry/kazakhstan-electric-power-industry-key-factors. The same information is published at: www.kazenergy.com/en/operation/electric-power-industry.
4. KEGOC was appointed as the system operator by the Governmental Resolution No. 630, dated 9 June 2014.
5. According to the information available at the official website of the Committee on Regulation of Natural Monopolies and Protection of Competition under the Ministry of National Economy of the Republic of Kazakhstan: www.gov.kz/memleket/entities/krem/search/1?contentType=news%2Carticle%2Cdocuments%2Ccurators&lang=ru&searchText=%D0%9C%D0%B5%D1%81%D1%82%D0%BD%D1%8B%D0%B9%20%D1%80%D0%B0%D0%B7%D0%B4%D0%B5%D0%BB%20%D0%93%D0%BE%D1%81%D1%83%D0%B4%D0%B0%D1%80%D1%81%D1%82%D0%B2%D0%B5%D0%BD%D0%BD%D0%BE%D0%B3%D0%BE%20%D1%80%D0%B5%D0%B3%D0%B8%D1%81%D1%82%D1%80%D0%B0%20%D1%81%D1%83%D0%B1%D1%8A%D0%B5%D0%BA%D1%82%D0%BE%D0%B2%20%D0%B5%D1%81%D1%82%D0%B5%D1%81%D1%82%D0%B2%D0%B5%D0%BD%D0%BD%D1%8B%D1%85%20%D0%BC%D0%BE%D0%BD%D0%BE%D0%BF%D0%BE%D0%BB%D0%B8%D0%B9&slug=krem.
6. Under Article 10.1.9 of the Law of the Republic of Kazakhstan 'On the Electricity Industry' (the "Electricity Industry Law").
7. Reference is made to a list of strategic deposits approved by the Governmental Resolution No. 389 dated 28 June 2018 (the "List of Strategic Deposits").
8. For reference, see the report: 'Technically Recoverable Shale Oil and Shale Gas Resources: Kazakhstan', prepared by the U.S Energy Information Administration available at: www.eia.gov/analysis/studies/worldshalegas/pdf/Kazakhstan_2014.pdf.
9. For more information, see www.kaztransgas.kz/index.php/ru.
10. For more information, see: www.intergas.kz.
11. For more information, see: www.agp.com.kz/?page_id=4048.
12. For more information, see: www.kazrosgas.org/eng/about-company.
13. For more information, see: www.bsgp.kz/en.
14. For more information, see: www.ktga.kz/en/company/about_us.
15. According to information available at the website of the Ministry of Energy of Kazakhstan: www.energo.gov.kz/index.php?id=2270 and the registers of natural monopolies available at: www.qazaqgaz.kz/index.php/en.
16. According to information available at the website of the Ministry of Energy of Kazakhstan: www.qazaqgaz.kz/index.php/en/main-page/general-information.

LATVIA

GENERAL	National regulatory authority (-ies)	The Public Utilities Commission
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU in electricity and gas
ELECTRICITY	Principal electricity generator(s)	AS Latvenergo
	Transmission system operator(s)	As Augstsprieguma tīkls
	Electricity distributor(s)	AS Sadales tīkls
	Principal electricity supplier(s)	AS Latvenergo, SIA Enefit
	Interconnectors	Direct interconnectors to Estonia and Russia
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Gas is both imported and exported. The largest importer is OAO Gazprom No shale gas
	Transportation system operator(s)	AS Conexus Baltic Grid
	Gas distributor(s)	AS Gaso
	Principal gas supplier(s)	AS Latvijas Gāze, AS Latvenergo
	Interconnectors	Direct interconnectors with Estonia, Lithuania and Russia

LITHUANIA

GENERAL	National regulatory authority (-ies)	The regulatory policy for the electricity sector is determined by the Lithuanian Parliament ("Parliament"), the Government of Lithuania ("Government") and the Ministry of Energy, and is monitored by the National Energy Regulatory Council ("Council"). The Council is responsible for ensuring effective competition in the electricity market, non-discrimination between customers and suppliers, and the provision of services of a certain quality to all customers. The Council also ensures that the Transmission System Operator ("TSO") and distribution system operators (DSOs) provide information to interested parties on interconnectors, grid usage and capacity allocation, as well as controlling the effective unbundling of accounts, etc. The Council applies the incentive regulation, ie sets the price caps of the regulated prices of the services provided by the energy undertakings, which, after reaching the set efficiency of their operations, enable the electricity undertakings to reduce costs thereby ensuring benefits to customers.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU

ELECTRICITY

Principal electricity generator(s)	• Ignitis gamyba/Elektrėnai complex (reserve power plant, a combined-cycle unit as well as biofuel and steam boilers) (1055MW) • Ignitis gamyba/pumped storage hydroelectric plant (900MW) • ORLEN Lietuva/natural gas-fired power plant (210MW) • Enefit Wind/wind parks (138.9MW) • Ignitis gamyba/hydroelectric power plant (101MW) • Amberwind/wind park (73.5MW) • Renerga/wind parks (57.5MW)
Transmission system operator(s)	LITGRID AB
Electricity distributor(s)	AB 'Energijos skirstymo operatorius' (the main operator serving 1.6 million customers throughout Lithuania) Operators of small-scale distribution networks: • UAB 'Dainavos elektra' • AB 'Akmenės cementas' • AB 'Lifosa' • AB 'Achema'
Principal electricity supplier(s)	• UAB 'Ignitis' • Elektrum Lietuva UAB • Enefit UAB • UAB 'EGTO energija' • MB Birštono Elektra
Interconnectors	• 'NordBalt': a submarine interconnection between Lithuania and Sweden which has been operational since 2015 • 'LitPol Link': an electricity link between Poland and Lithuania that connects the Baltic transmission system to the synchronous grid of Continental Europe. It has a capacity of 500MW and since 2021 it has operated in a synchronous regime

LITHUANIA

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Lithuania is a gas importing country. The main countries from which gas is imported are: • United States of America (liquefied natural gas ("LNG")) • Norway (LNG) • Trinidad and Tobago (LNG) Shale gas is not used in Lithuania. However, a study by the U.S. Energy Information Administration indicated that Lithuania could have recoverable reserves of 481 billion cubic metres ("bcm") of shale gas. The technological possibility of extraction is one quarter of that amount (around 100bcm).
	Transportation system operator(s)	AB 'Amber Grid'
	Gas distributor(s)	AB 'Energijos skirstymo operatorius' (the main operator serving most of the customers throughout Lithuania) Operators of small-scale distribution networks: • AB agrofirma 'Josvainiai' • UAB 'INTERGAS' • UAB Gren Lietuva • UAB 'SG dujos'
	Principal gas supplier(s)	• UAB 'Ignitis' • UAB 'Imlitex' • Enefit UAB • UAB 'HAUPAS' • UAB Elenger • Axpo Nordic, AS
	Interconnectors	• Poland-Lithuania (GIPL): a gas pipeline between Poland and Lithuania. Natural gas can flow in both directions. The project is being implemented by the gas TSOs AB 'Amber Grid' (Lithuania) and Gaz-System SA (Poland). The pipeline, which became operational in May 2022, ended the energy isolation of the Baltic States and Finland, integrating the countries into the EU's single gas network. • Lithuania's well-developed gas transmission system serves as a regional corridor for the transmission of gas northwards to Latvia and southwards to Poland. • With the construction of the Klaipėda LNG terminal, Lithuania has been able to feed most of the gas for Lithuanian and Baltic needs into the transmission system through the Klaipėda LNG terminal. In recent years, 65% of the gas needed has been supplied through the terminal. • Belarus-Lithuania • Latvia-Lithuania • Kaliningrad (Russia)-Lithuania

LUXEMBOURG

GENERAL	National regulatory authority (-ies)	Institut Luxembourgeois de Régulation
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Exemption for small grids (Article 66 (3) Fourth Electricity Directive and Article 49 (6) Third Gas Directive)
ELECTRICITY	Principal electricity generator(s)	Société Electrique de l'Our (SEO)
	Transmission system operator(s)	• Creos • Sotel (industrial grid)
	Electricity distributor(s)	• Creos • Electris (Hoffmann Frères S.à.r.l. et Cie S.e.c.s.) • Sudstroum • Ville d'Ettelbruck • Ville de Diekirch
	Principal electricity supplier(s)	• Enovos • Leo • Electris • Sudstroum • Steinergy • NordENERGIE
	Interconnectors	Luxembourg has electricity interconnectors with the following countries: • Germany (Creos) • Belgium and France (Sotel)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • Belgium • Germany No shale gas production.
	Transportation system operator(s)	Creos
	Gas distributor(s)	• Creos • SUDenergie • Ville de Dudelange
	Principal gas supplier(s)	• Enovos • Leo • SUDenergie • Electris
	Interconnectors	Luxembourg has gas interconnectors, through Creos, with the following countries: • Germany • Belgium • France

MALTA

GENERAL	National regulatory authority (-ies)	• ERA (Environment and Resources Authority) • MRA (Malta Resources Authority) • REWS (Regulator for Energy and Water Services) • EWA (Energy and Water Agency)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	There are no transmission system operators in Malta, which has derogations from Articles 9 and 26 of the Third Electricity Directive.
ELECTRICITY	Principal electricity generator(s)	Enemalta
	Transmission system operator(s)	NIL
	Electricity distributor(s)	Enemalta Corporation
	Principal electricity supplier(s)	• Electrogas Malta Limited • D3 (Delimara 3); Generation Limited, previously known as Burmeister & Wain Scandinavian Contractor A/S (BWSC) Power Station
	Interconnectors	The Electricity Interconnector between Malta and Sicily which connects the country to the European Grid, was inaugurated in April 2015. In 2017, the Interconnector supplied 38% of Malta's total energy consumption. The EWA has made substantial progress in relation to the second Malta- Italy interconnector which is expected to be completed by the year 2025.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Malta remains an importer of gas. The power Station at Delimara was officially demolished in September 2018 as per Enemalta's plan to revamp Malta's electricity generation sector by ending the use of the less efficient, oil-fired generators. The liquefied natural gas ("LNG") Tanker which provided temporary LNG to the new power plant in Delimara was replaced with the gas pipeline interconnector project which will be operating between Malta and Sicily.
	Transportation system operator(s)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	Gas distributor(s)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	Principal gas supplier(s)	Easygas (Malta) Ltd and Liquigas Malta Ltd
	Interconnectors	A gas pipeline has been proposed, containing a supply capacity of 232,000Sm3/hr and 159km in length and will be installed between Sicily and Malta. This project is being co-founded by the European Union (EU) under the Connecting Europe Facility (CEF) Programme for 2014-2020.

MOLDOVA

GENERAL	National regulatory authority (-ies)	National regulatory authority: The National Agency for Energy Regulation (ANRE). Further involved authorities include: • The Government of Moldova • The Ministry of Economy and Infrastructure • The Energy Efficiency Agency • Local authorities
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	All regimes (FOU, ISO or ITO) are possible. Moldova has opted to provide TSOs to choose between the FOU, ISO and ITO models.
ELECTRICITY	Principal electricity generator(s)	• Termoelectrica SA • CET Nord SA • Moldavskaia GRES
	Transmission system operator(s)	Moldelectrica IS
	Electricity distributor(s)	• RED Nord SA • ICS RED Union Fenosa SA
	Principal electricity supplier(s)	• ICS Premier Energy SRL • Furnizarea Energiei Electrice Nord SA • Energocom SA
	Interconnectors	Moldova has interconnections with Romania (five interconnectors) and Ukraine (20 interconnectors).
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer. Moldova mainly, imports from the Russian Federation. No shale gas extraction has been implemented.
	Transportation system operator(s)	• Moldovatransgaz SRL • Vestmoldtransgaz SRL
	Gas distributor(s)	• Chisinau-Gas SRL • Ialoveni-Gaz SRL • Balti-Gaz SRL • IM Rotalin Gaz Trading SRL • Ungheni-Gaz SRL etc. (27 DSOs).
	Principal gas supplier(s)	Moldovagaz SA
	Interconnectors	Moldova has interconnections with Romania (one interconnector) and Ukraine (five interconnectors).

MONTENEGRO

GENERAL	National regulatory authority (-ies)	The Government of Montenegro, which together with the Montenegrin Parliament, is the key authority regulating the energy sector. The Ministry of Capital Investments of Montenegro is in charge of activities related to electricity, energy policy and energy efficiency matters. The Directorate for Energy and Energy Efficiency within the Ministry of Capital Investments (*Direktorat za energetiku i energetsku efikasnost*) conducts activities regarding the preparation and assessment of investment projects in Montenegro, as well as managing development policy, monitoring sector activities and taking measures in the field of energy and energy efficiency. The Energy and Water Regulatory Agency of Montenegro (*Regulatorna agencija za energetiku i komunalne djelatnosti Crne Gore*) ("REGAGEN") regulates the energy market by overseeing the generation, transmission, distribution, market operation and supply activities.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	Elektroprivreda Crne Gore ad Nikšić ("EPCG") is the national electricity utility and is owned by the State of Montenegro (98.5430%) and several minority shareholders.
	Transmission system operator(s)	Crnogorski elektroprenosni system ("CGES") is the Montenegrin TSO jointly held by the State (55%), Italian company Terna - Rete Elettrica Nazionale S.p.A. (22%); and Elektromreža Srbije ad ("EMS"), the Serbian TSO (10%) and several minority shareholders.
	Electricity distributor(s)	Crnogorski eletrkodistributivni system ("CEDIS") is the Montenegrin DSO founded by and in the sole ownership of EPCG.
	Principal electricity supplier(s)	EPCG
	Interconnectors	Montenegro has 12 cross-border interconnections with Serbia, Kosovo, Bosnia and Herzegovina, Italy and Albania. The interconnections range from 110kV up to 440kV capacity, as follows: • Serbia: two interconnectors of 220kV and one interconnector of 110kV • Kosovo: one interconnector of 440kV • Bosnia and Herzegovina: one interconnector of 400kV, two interconnectors of 220kV and two interconnectors of 110kV • Albania: one interconnector of 220kV and one interconnector over 400kV • Italy: subsea power transmission cable (the initial capacity of the interconnection is 600MW)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Gas importer from Russia. There is no shale gas in Montenegro.
	Transportation system operator(s)	Montenegro Bonus' d.o.o. Cetinje
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	N/A

NETHERLANDS

GENERAL	National regulatory authority (-ies)	Authority for Consumers and Markets
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity - FOU • Gas - FOU
ELECTRICITY	Principal electricity generator(s)	• RWE (Essent) • Engie • Vattenfall (Nuon)
ELECTRICITY	Transmission system operator(s)	TenneT TSO
ELECTRICITY	Electricity distributor(s)	• Liander • Enexis • Stedin • Rendo Netwerken • Westland Infra • Coteq Netbeheer
ELECTRICITY	Principal electricity supplier(s)	• Innogy (Essent) • Vattenfall (Nuon) • Eneco • Nuts Groep • Greenchoice • Engie
ELECTRICITY	Interconnectors	• Germany (3,949MW) • Belgium (1,501MW) • United Kingdom (1,000MW) • Norway (700MW) • Denmark (700MW)

NETHERLANDS

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Net gas importer country (as from 2018). Imports via pipeline mainly from Norway and as LNG from the US, Africa and the Middle East. No shale gas
	Transportation system operator(s)	Gasunie Transport Services
	Gas distributor(s)	• Liander • Enexis • Stedin • Rendo Netwerken • Westland Infra • Coteq Netbeheer
	Principal gas supplier(s)	• Innogy (Essent) • Vattenfall (Nuon) • Eneco • Delta
	Interconnectors	• Germany • Belgium • United Kingdom

NORTH MACEDONIA

GENERAL	National regulatory authority (-ies)	Energy and Water Services and Services for Municipal Waste Management Regulatory Commission of the Republic of North Macedonia.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU (imposed regime with the Energy Law (2018) and yet to be implemented with respect to the natural gas market).
ELECTRICITY	Principal electricity generator(s)	JSC Power Plants of North Macedonia (JSC ESM) Skopje.
	Transmission system operator(s)	Electricity Transmission System Operator (TSO) of the Republic of North Macedonia, JSC for Transmission of Electricity and Management with the Electricity System, state-owned, Skopje (JSC MEPSO).
	Electricity distributor(s)	• Elektrodistribucija SPLLC Skopje; and • JSC ESM Skopje (on the territory of the industrial complex of the former 'Mines and Ironworks – Skopje', Municipality of Butel and Municipality of Gazi Baba).
	Principal electricity supplier(s)	• EVN Macedonia Elektrosnabduvanje SPLLC Skopje • EDS LLC Skopje • GEN-I Sale of Energy LLC Skopje • Energy Financing Group AD Sofia – branch office Skopje
	Interconnectors	• Serbia (400kV lines) • Bulgaria (400kV lines) • Greece (2 x 400kV lines) • Kosovo (400kV lines)
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from Russia. No shale gas reserves have been discovered.
	Transportation system operator(s)	JSC for performing energy activity natural gas transmission NOMAGAS Skopje in State Ownership.
	Gas distributor(s)	• Directorate for Technological Industrial Development Zones ("DTIDZ Skopje") • PU Kumanovo – Gas Kumanovo • PU Strumica – Gas Strumica
	Principal gas supplier(s)	• Makpetrol Prom-Gas SPLLC Skopje • Bumak Primo SPLLC Skopje • TE-TO Gas Trade SPLLC Skopje • DTIDZ Skopje • PU Kumanovo – Gas Kumanovo • PU Strumica – Gas Strumica • ESM Trade SPLLC Skopje
	Interconnectors	Bulgaria (a cul-de-sac branch of the Russian pipeline supply system crossing Ukraine, Moldova, Romania, and Bulgaria, with capacity of 800 million mm^3 per year).

NORWAY

GENERAL	National regulatory authority (-ies)	Norwegian Energy Regulatory Authority (NVE-RME) (electricity sector) Norwegian Petroleum Directorate (NPD) (upstream gas activities)
GENERAL	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• FOU (electricity sector) • ISO (upstream gas sector)
ELECTRICITY	Principal electricity generator(s)	• Statkraft • Hafslund Eco • Lyse Kraft
ELECTRICITY	Transmission system operator(s)	Statnett SF
ELECTRICITY	Electricity distributor(s)	Over 150 companies are involved in grid operations at one or more grid levels. Elvia AS is the largest distribution grid company serving 900,000 customers.
ELECTRICITY	Principal electricity supplier(s)	There are a large number of companies involved in generation, supply and trading. Statkraft Energi AS is the largest supplier.
ELECTRICITY	Interconnectors	• Sweden: about 3650MW • Finland: about 100MW • Denmark: 1700MW • The Netherlands: 700MW • Russia: 50MW • Germany: 1400MW • UK: 1400MW (North Sea Link)

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Norway is a gas exporter. Norway does not have shale gas reserves.
	Transportation system operator(s)	Domestic transmission system not developed. Gassco AS is the ISO for the upstream gas pipeline system on and from the Norwegian continental shelf.
	Gas distributor(s)	N/A
	Principal gas supplier(s)	N/A
	Interconnectors	• Vesterled (UK) • Langeled (UK) • FLAGS (UK) • Zeepipe (Belgium) • Franpipe (France) • Norpipe (Germany) • Europipe I (Germany) • Europipe II (Germany)

POLAND

GENERAL	National regulatory authority (-ies)	The President of the Energy Regulatory Authority (*Prezes Urzędu Regulacji Energetyki*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	In practice, the FOU model has been adopted. The State Treasury is the sole shareholder of the TSO.
ELECTRICITY	Principal electricity generator(s)	• PGE Polska Grupa Energetyczna capital group • TAURON Polska Energia capital group • ENEA capital group • Orlen capital group
	Transmission system operator(s)	Polskie Sieci Elektroenergetyczne S.A.
	Electricity distributor(s)	• PGE Dystrybucja SA • Tauron Dystrybucja SA • ENEA Operator sp. z o.o. • ENERGA-Operator SA • Innogy Stoen Operator sp. z o.o
	Principal electricity supplier(s)	• PGE Obrót SA • Tauron Sprzedaż sp. z o.o. • ENEA S.A. • ENERGA-OBRÓT S.A.
	Interconnectors	• LitPol Link: Ełk-Alytus (Lithuania) • SwePol: Słupsk Wierzbięcino -Storno (Sweden) • Krajnik-Vierraden (Germany) • Mikułowa-Hagenverder (Germany) • Wielopole/Dobrzeń- Nosovice/Albrechtice (Czech Republic) • Kopanina/Bujaków-Liskovec (Czech Republic) • Krosno Iskrzynia-Lemesany (Slovakia) • Rzeszów-Chmielnicka (Ukraine, currently not operational) • Zamość-Dobrotwór (Ukraine, allows only for electricity import)

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer country. To date, no economically viable shale gas resources have been confirmed.
Transportation system operator(s)	OGP GAZ-SYSTEM S.A.
Gas distributor(s)	Polska Spółka Gazownictwa sp. z o.o. (main distributor) Others: • EWE Energia sp. z o.o. • G.EN Gaz Energia SA • Duon Dystrybucja SA • Polenergia Kogeneracja sp. z o.o. • SIME Polska sp. z o.o., and Enesta sp. zo.o.
Principal gas supplier(s)	• PGNiG S.A. • PGNiG Obrót Detaliczny sp. z o.o.
Interconnectors	• Kamminke (Germany) • Gubin (Germany) • Lasów (Germany) • Mallnow (Germany) • Branice (Czech Republic) • Cieszyn (Czech Republic) • Drozdowicze (Ukraine) • Wysokoje (Belarus) • Tietierowka (Belarus) • Kondratki (Belarus)

PORTUGAL

GENERAL	National regulatory authority (-ies)	• Portuguese Energy Services Regulatory Authority (*Entidade Reguladora dos Servicos Energeticos*) (ERSE) • Directorate General of Energy and Resources (*Direcção Geral de Energia e Geologia*) (DGEG)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	• EDP (*Gestão da Produção de Energia, S.A.*) • EDP Renováveis • Finerge • Iberwind • Trustwind
	Transmission system operator(s)	REN (*Redes Eléctricas Nacionais, S.A.*)
	Electricity distributor(s)	• A Celer – Cooperativa Electrificação de Rebordosa, CRL • A Eléctrica Moreira de Cónegos, CRL • Casa do Povo de Valongo do Vouga, CRL • Cooperativa Eléctrica de Loureiro, CRL • Cooperativa Eléctrica S. Simão de Novais, CRL • Cooperativa Eléctrica de Vale D'Este, CRL • Cooperativa Eléctrica de Vilarinho, CRL • Cooperativa Electrificação A Lord, CRL • Cooproriz – Cooperativa de Abastecimento de Energia Eléctrica, CRL • E-REDES – Distribuição de Eletricidade, S.A. • Junta de Freguesia de Cortes do Meio
	Principal electricity supplier(s)	• EDP Comercial – Comercialização de Energia, S.A. • SU ELETRICIDADE, S.A. • Endesa Energia, S.A. – Sucursal Portugal • Galp Power, S.A. • GOLD ENERGY – Comercializadora de Energia, S.A. • Iberdrola Clientes Portugal, Unipessoal Lda
	Interconnectors	Portugal does not currently have any electricity interconnectors.

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Portugal has no natural gas resources of its own; the supply of gas is maintained through long-term take-or-pay contracts (the main natural gas suppliers being Algeria and Nigeria). Although shale gas is uncommon, some studies have highlighted the potential for shale gas in Portugal.
Transportation system operator(s)	REN-Gasodutos, S.A.
Gas distributor(s)	Operators of regional distribution networks (concession holders): • Setgás – Sociedade de Distribuição de Gás Natural, S.A. • Lisboagás GDL – Sociedade Distribuidora de Gás Natural de Lisboa, S.A. • Lusitaniagás – Companhia de Gás do Centro, S.A. • Tagusgás – Empresa de Gás do Vale do Tejo, S.A. • Beiragás – Companhia de Gás das Beiras, S.A. • REN Portgás Distribuição, S.A. Operators of local distribution networks (licence holders): • Duriensegás – Sociedade Distribuidora de Gás Natural do Douro, S.A. • Paxgás – Sociedade Distribuidora de Gás Natural de Beja, S.A. • Medigás – Sociedade Distribuidora de Gás Natural do Algarve, S.A. • Dianagás – Sociedade Distribuidora de Gás Natural de Évora, S.A. • Sonorgás S.A.
Principal gas supplier(s)	• CEPSA GAS Comercializadora, S.A. • Cepsa Portuguesa Petróleos, S.A. • EDP Comercial – Comercialização de Energia, S.A. • EDP GÁS.COM – Comércio de Gás Natural, S.A. • Endesa Energia, S.A. – Sucursal Portugal • Energia Simples • Galp Gás Natural, S.A. • Galp Power, S.A. • Gas Natural Comercializadora, S.A. • GOLD ENERGY – Comercializadora de Energia, S.A. • Iberdrola Clientes Portugal, Unipessoal, Lda. • LUSIADAENERGIA, S.A. • Molgás, Energia Portugal, S.A. • Rolear – Automatizações, Estudos e Representações, S.A.
Interconnectors	• Portugal does not currently have any gas interconnectors.

ROMANIA

GENERAL	National regulatory authority (-ies)	Romanian Energy Regulatory Authority (*Autoritatea Nationala de Reglementare in Domeniul Energiei Electrice*) (ANRE)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU
ELECTRICITY	Principal electricity generator(s)	Hidroelectrica S.A., Nuclearelectrica S.A., Complexul Energetic Oltenia S.A. and OMV Petrom S.A.
	Transmission system operator(s)	Transelectrica S.A.
	Electricity distributor(s)	Delgaz Grid, Distributie Energie Oltenia, E-Distributie Muntenia, E-Distributie Banat, E-Distributie Dobrogea and Distribuție Energie Electrica Romania
	Principal electricity supplier(s)	CEZ Vanzare S.A., ENEL Energie S.A., E.ON Energie Romania S.A., ENEL Energie Muntenia S.A., Electrica Furnizare S.A. and Tinmar Energy
	Interconnectors	Romania-Bulgaria: • Overhead line 400kV Isaccea – Dobrudja • Overhead line 400kV Țânțăreni – Kozlodui • Overhead line 400kV Isaccea – Varna • Overhead line 220kV Ișalnița – Kozlodui Romania-Serbia: • Overhead line 400kV Porțile de Fier – Djerdap • Overhead line 110kV Ostrovul Mare – Kusjak • Overhead line 110kV Gura Văii – Șip • Overhead line 110kV Jimbolia – Kikinda Romania-Hungary: • Overhead line 400kV Arad – Sandorfalva • Overhead line 400kV Nadab – Bekescsaba

ELECTRICITY (continued)	Interconnectors (continued)	Romania-Ukraine: • Overhead line 400kV Roșiori – Mukacevo • Overhead line 700kV Isaccea – Ucraina Sud Romania-Moldova: • Overhead line 400kV Isaccea – Vulcănești • Overhead line 110kV Stânca – Costești • Overhead line 110kV Huși – Cioara • Overhead line 110kV Țuțora – Ungheni • Overhead line 110kV Falciu – Gotesti
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Romania is an importer. In 2020, Romania imported gas accounting for 18.79% of consumption, mainly from Russia. There is no shale gas.
	Transportation system operator(s)	Transgaz S.A.
	Gas distributor(s)	Delgaz Grid S.A., Distrigaz Sud Retele, Premier Energy and Gaz Est
	Principal gas supplier(s)	Engie Romania, E.ON Energie Romania S.A., Romgaz, OMV Petrom and Premier Energy
	Interconnectors	• Csanádpalota/FGSZ (HU) • Ruse-Giurgiu/Bulgartransgaz (BG) • Ungheni/Vestmoldtransgaz (MD) • Negru Voda 1/Bulgartransgaz (BG) • Negru Voda 2/Bulgartransgaz (BG) • Negru Voda 3/Bulgartransgaz (BG) • Mediesu Aurit Import/Ukrtransgaz (UA) • Isaccea Import/Ukrtransgaz (UA) • Isaccea 1,2,3/Ukrtransgaz (UA)

SERBIA

GENERAL	National regulatory authority (-ies)	The Government of the Republic of Serbia; The Ministry of Mining and Energy of the Republic of Serbia; and Energy Agency of the Republic of Serbia (AERS).
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	Javno preduzeće Elektroprivreda Srbija ("JP EPS")
	Transmission system operator(s)	Elektromreža Srbije ("EMS")
	Electricity distributor(s)	Elektrodistribucija Srbije d.o.o.
	Principal electricity supplier(s)	EPS Snabdevanje (Branch of JP EPS)
	Interconnectors	• Bulgaria: 440kV • Hungary: 440kV • Macedonia: one of 440kV and two of up to 220kV • Montenegro: one of 440kV and two of 220kV • Albania: up to 220kV • Bosnia and Herzegovina: one of 440kV and one of up to 220kV • Croatia: 440kV • Romania: 440kV • Croatia: 440kV
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer (Russia).
	Transportation system operator(s)	• JP Srbijagas ("Srbijagas") • Yugorosgaz-Transport
	Gas distributor(s)	Srbijagas and 63 licensed suppliers of natural gas.
	Principal gas supplier(s)	• JP Srbijagas ("Srbijagas") • Yugorosgaz a.d. • NOVI SAD GAS d.o.o. za distribuciju gasa, održavanje I izvođenje, Novi Sad
	Interconnectors	Serbia has two gas pipeline systems interconnections with neighbouring countries (one entry and exit point), such as gas pipelines: (i) Hungary-Serbia (Kishkundorozhma - entry point) and (ii) Serbia-Bosnia and Herzegovina (Zvornik - exit point of interconnection).

SLOVAKIA

GENERAL	National regulatory authority (-ies)	The Ministry of Economy of the Slovak Republic and the Regulatory Office for Network Industries
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	ITO
ELECTRICITY	Principal electricity generator(s)	Slovenské elektrárne, a.s.
	Transmission system operator(s)	Slovenská elektizačná prenosová sústava, a.s.
	Electricity distributor(s)	Západoslovenská distribučná, a.s., Stredoslovenská distribučná, a.s., Východoslovenská distribučná, a.s.
	Principal electricity supplier(s)	Západoslovenska energetika, a.s., Stredoslovenská energetika, a.s., Východoslovenská energetika, a.s.
	Interconnectors	Five interconnectors with the Czech Republic, four with Hungary, one double line to Poland and one to Ukraine.
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer – mainly Russian gas
	Transportation system operator(s)	eustream, a.s.
	Gas distributor(s)	SPP – distribúcia, a.s.
	Principal gas supplier(s)	Slovenský plynárenský priemysel, a.s.
	Interconnectors	One interconnector with Austria, one with the Czech Republic, two with Ukraine and one with Hungary.

SLOVENIA

GENERAL	National regulatory authority (-ies)	• Energy Agency of the Republic of Slovenia • Slovenian Environment Agency • Energy Directorate within the Ministry of Infrastructure • The Government Office of the Republic of Slovenia of Climate Change
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity: FOU • Gas: ITO
ELECTRICITY	Principal electricity generator(s)	• HSE Group (including, among others, HSE, d.o.o., TEŠ d.o.o. and DRAVSKE ELEKTRARNE MARIBOR d.o.o.) • GEN Group (including inter alia NUKLEARNA ELEKTRARNA KRŠKO d.o.o. and Hidroelektrane na Spodnji Savi, d.o.o.) • ENERGETIKA LJUBLJANA, d.o.o.
	Transmission system operator(s)	ELES, d.o.o., sistemski operater prenosnega elektroenergetskega omrežja
	Electricity distributor(s)	SODO sistemski operater distribucijskega omrežja z električno energijo, d.o.o. whereby certain activities are subcontracted to: • ELEKTRO CELJE, d.d. • ELEKTRO GORENJSKA, d.d. • ELEKTRO LJUBLJANA d.d. • ELEKTRO MARIBOR d.d. • ELEKTRO PRIMORSKA d.d.
	Principal electricity supplier(s)	• GEN-I, d.o.o. • ECE, energetska družba, d.o.o. • Energija plus d.o.o. • ELEKTRO ENERGIJA d.o.o. • E 3, d.o.o. • PETROL d.d., Ljubljana
	Interconnectors	ELES has a cross border connection with neighbouring countries: • Austria (Maribor – Kainachtal, Podlog – Obersielach) • Italy (Divača – Redipuglia, Divača – Padriciano) • Croatia (Krško – Tumbri, Divača – Melina, Divača – Pehlin, Cirkovce – Žerjavinec) • A Hungary-Slovenia interconnection (Cirkovce – Pince) has not been fully completed and is currently undergoing acceptance testing and commissioning.

GAS		
	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	According to the 2021 Annual Energy Agency's Report on the Energy Sector in Slovenia, 99% of all gas in Slovenia is imported, with the majority from Austria (about 85%).
	Transportation system operator(s)	PLINOVODI, Družba za upravljanje s prenosnim sistemom, d.o.o.
	Gas distributor(s)	The distribution of natural gas in Slovenia is performed by numerous gas distribution system operators. Gas distributors are either public companies or private companies which have acquired a concession.
	Principal gas supplier(s)	• GEOPLIN d.o.o. Ljubljana • PETROL d.d. Ljubljana
	Interconnectors	Three cross-border interconnectors with the Slovenian transmission system exist: • Ceršak on Austrian border • Rogatec on Croatian border • Šempeter on Italian border A Hungary-Slovenia interconnection (R15/1 Pince – Lendava – Kidričevo) is being developed and has been approved as part of the EU's Projects of Common Interest (PCI) as project no. 6.23.

SPAIN

GENERAL	National regulatory authority (-ies)	• National Markets and Competition Commission (*Comisión Nacional de los Mercados y de la Competencia*) (CNMC) • Spanish Ministry for Ecological Transition and the Demographic Challenge (*Ministerio para la Transición Ecológica y el Reto Demográfico*) (MITERD)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	• Electricity – FOU • Natural gas – FOU and ISO
ELECTRICITY	Principal electricity generator(s)	• Iberdrola • Endesa • Naturgy • EDP
	Transmission system operator(s)	Red Eléctrica de España (REE)
	Electricity distributor(s)	• Endesa • Iberdrola • Naturgy • Hidrocantábrico Distribución (EDP) • Viesgo (EDP)
	Principal electricity supplier(s)	• Endesa • Iberdrola • Naturgy • TotalEnergies
	Interconnectors	• France • Morocco • Portugal • Andorra

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer from: • USA • Algeria • Nigeria • France • Russia • Qatar • Belgium • Norway • Portugal Although studies suggest that there could be important reservoirs of shale gas in the North of Spain, strong opposition from certain political parties and regional governments has prevented them from being explored further. In addition, Law 7/2021 has expressly prohibited any activities for the exploitation of hydrocarbons where the use of high-volume hydraulic fracturing is foreseen.
	Transportation system operator(s)	• Enagas • Reganosa
	Gas distributor(s)	• Nedgia (Naturgy Group) • Nortegas • Madrileña Red de Gas • Redexis Gas • Gas Extremadura
	Principal gas supplier(s)	• Naturgy • EDP • Fenosa Gas • Endesa Gas • HolaLuz • Repsol • Iberdrola
	Interconnectors	• France (Larrau and Irun) • Portugal (Badajoz and Tuy) • Morocco • Algeria

SWEDEN

GENERAL	National regulatory authority (-ies)	Energy Markets Inspectorate (*Energimarknadsinspektionen*)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU for electricity, combination of FOU and ISO for gas
ELECTRICITY	Principal electricity generator(s)	Vattenfall, E.ON, Fortum, Juniper and Statkraft
	Transmission system operator(s)	Svenska kraftnät
	Electricity distributor(s)	Vattenfall, E. ON and Ellevio
	Principal electricity supplier(s)	Vattenfall, E.ON and Fortum
	Interconnectors	Svenska kraftnät, Baltic Cable AB and SwePol Link AB
GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Natural gas is imported from Denmark. Liquefied natural gas (LNG) is imported via a pipeline from Denmark and via shipping vessels from, among other places, Norway. There is no shale gas in Sweden.
	Transportation system operator(s)	Swedegas
	Gas distributor(s)	Gasnätet Stockholm, Göteborg Energi, Kraftringen, Swedegas, Varberg Energi, WEUM Gas, Öresundskraft.
	Principal gas supplier(s)	ApportGas, E.ON, Göteborg Energi, Kraftringen Energi, Varberg Energi, Öresundskraft and Stockholm Gas.
	Interconnectors	Swedegas

SWITZERLAND

GENERAL	National regulatory authority (-ies)	Federal Department of the Environment, Transport, Energy and Communications (DETEC) Swiss Federal Office for Energy (SFOE) Swiss Federal Electricity Commission (ie ElCom)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU as of 1 January 2013.
ELECTRICITY	Principal electricity generator(s)	• Alpiq Group • Axpo Group • BKW Energie • Repower • Elektrizitatswerke der Stadt Zurich (EWZ)
	Transmission system operator(s)	Swissgrid AG
	Electricity distributor(s)	Multiple different distributors of various sizes.
	Principal electricity supplier(s)	• Alpiq Group • Axpo Group • BKW Energie • Repower • Elektrizitatswerke der Stadt Zurich (EWZ)
	Interconnectors	• Austria (APG) • France (RTE) • Germany (TransnetBW, Amprion) • Italy (Terna)

SWITZERLAND

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Importer: • Russia • Norway • EU There is no shale gas in Switzerland.
	Transportation system operator(s)	Transitgas AG operates the transit pipeline alongside various regional and local distribution network operators.
	Gas distributor(s)	Multiple regional and local distributors.
	Principal gas supplier(s)	• Swissgas AG • EGO • EGZ • GVM • Gaznat S.A.
	Interconnectors	Transitgas Pipeline: • Wallbach (Germany) • Rodersdorf/Oltingue (France) • Griess Pass (Italy)

TURKEY

GENERAL	National regulatory authority (-ies)	• For electricity and downstream oil & gas: Energy Market Regulatory Authority (EMRA) • For upstream oil & gas: General Directorate of Mining and Petroleum Affairs (GDPA)
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	Both ISO and ITO models are used. The transmission operators are both fully state-owned: • Electricity: Türkiye Elektrik İletim AŞ (TEİAŞ) • Natural Gas: Boru Hatları İle Petrol Taşıma AŞ (BOTAŞ)
ELECTRICITY	Principal electricity generator(s)	• As of 28 June 2021, there were 1886 electricity generation licences in force. • State-owned Elektrik Üretim AŞ (EÜAŞ) is the principal electricity generation company.
	Transmission system operator(s)	Türkiye Elektrik İletim AŞ (TEİAŞ)
	Electricity distributor(s)	The distribution network is divided into 21 regions, with one distribution company in each. All of these companies have been privatised.
	Principal electricity supplier(s)	As of 28 June 2021, there were 219 supply licences in force.
	Interconnectors	Interconnection lines with net transfer capacities: • Bulgaria • Greece • Azerbaijan (Nakhcivan) • Iran • Georgia • Armenia • Syria • Iraq

TURKEY

GAS

Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Turkey is an importer country. As of December 2020, the gas was imported from: • Russian Federation (33.59%) (through pipeline) • Iran (11.06%) (through pipeline) • Azerbaijan (24%) (through pipeline) • Algeria (11.58%) (LNG) • Niger (2.82%) (LNG) • Other (16.95%)
Transportation system operator(s)	The state-owned BOTAŞ owns and operates the gas transmission network.
Gas distributor(s)	The distribution network is divided into regions, with one distribution company in each. Turkey continues to privatise the gas distribution companies. As of 28 June 2021, there were 72 distribution licences in force.
Principal gas supplier(s)	The principal gas supplier is BOTAŞ.
Interconnectors	Turkey has the following gas interconnectors: • Trans-Anatolian Natural Gas Pipeline ("TANAP") • TurkStream Natural Gas Pipeline • Russia-Turkey Western Route Natural Gas Pipeline • Russia-Turkey Blue Stream Natural Gas Pipeline • Iran-Turkey Natural Gas Pipeline • Baku-Tbilisi-Erzurum Natural Gas Pipeline • Interconnector Turkey-Greece

UKRAINE

GENERAL	National regulatory authority (-ies)	• Ministry of Energy of Ukraine • National Energy and Utilities Regulatory Commission • State Geology and Subsoil Service of Ukraine • Ministry of Ecology and Natural Resources of Ukraine • State Agency on Energy Efficiency and Energy Saving of Ukraine
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	The unbundling process within the gas market was fully completed on 1 January 2020 based on the ISO model. The unbundling process within the electricity market is still ongoing based on the ISO model.
ELECTRICITY	Principal electricity generator(s)	• State Enterprise 'National Atomic Energy Company Energoatom – operates all Ukrainian NPPs • PrJSC Ukrhydroenergo – state-owned hydro generating company that owns most of Ukrainian HPPs • PJSC Centrenergo – state-owned thermal generating company • DTEK Group • Scatec Solar Group • Eurocape Group • CNBM Group • Windkraft Group
	Transmission system operator(s)	Private Joint Stock Company National Power Company Ukrenergo, which is wholly owned by the State.
	Electricity distributor(s)	Entities licensed for distribution of electricity (DSOs). Functions of DSOs are usually performed by regional distribution companies. The Ukrainian Law requires the DSOs to be unbundled from electricity generation, supply and transmission also in terms of ownership.
	Principal electricity supplier(s)	Entities licensed for supply of electricity. Formation of final prices for the supply of electricity is not subject to regulation, except in case of universal services suppliers and last resort suppliers. Universal services suppliers provide the supply services only to household customers and small non-household customers. Ukraine appointed State Enterprise Ukrinterenergo as the last resort supplier for the period from 1 January 2019 to 31 December 2021.
	Interconnectors	Private Joint Stock Company National Power Company Ukrenergo (TSO) or DSOs, depending on the operator of the respective grid lines.

UKRAINE

GAS	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	From 2018, imports from the European market are the sole source of imported natural gas. Importer from Poland, Hungary and Slovak Republic. There are two main fields of shale gas, ie Oleske and Yuzivske.
	Transportation system operator(s)	LLC Gas TSO of Ukraine
	Gas distributor(s)	Entities licensed for distribution of gas (DSOs). Functions of DSOs are usually performed by regional distribution companies.
	Principal gas supplier(s)	• LLC Gas supply company Naftogaz of Ukraine – gas supply to consumer households • LLC Gas supply company Naftogaz Trading – gas supply to industrial customers • LLC Naftogaz Teplo – gas supply to heat-generating companies
	Interconnectors	LLC Gas TSO of Ukraine

UNITED KINGDOM

GENERAL	National regulatory authority (-ies)	The Gas and Electricity Markets Authority, acting through Ofgem.
	Unbundling regime: full ownership unbundling ("FOU"), independent system operator ("ISO"), independent transmission operator ("ITO") model	FOU, ISO and the "unbundling derogation providing greater independence than the ITO model" pursuant to Article 9(9) of the New Electricity and Gas Directives are available in both the electricity and gas markets. ITO model is only available for gas interconnectors.
ELECTRICITY	Principal electricity generator(s)	• RWE • EDF • E.ON • Scottish and Southern Energy • Scottish Power • Centrica • Drax Power • GDF SUEZ • Energy UK • Orsted • Intergen
	Transmission system operator(s)	National Grid Electricity System Operator
	Electricity distributor(s)	• SSE • UK Power Networks • Northern Power Grid • Electricity Northwest • Scottish Power • Western Power Distribution
	Principal electricity supplier(s)	• EDF • E.ON • RWE(nPower) • Centrica • Scottish Power • Scottish • Southern Power
	Interconnectors	4G W of capacity: • Interconnexion France Angleterre (IFA1 and IFA2) • Moyle • Britned • Nemo Link • North Sea Link • Republic of Ireland (East West (EWIC)) • Eleclink

GAS		
	Importer or exporter country? (name origin of gas if importer) Any shale gas in the jurisdiction?	Net importer. Gas is imported from Belgium, the Netherlands and Norway via Pipelines and as LNG via ship from several countries including Qatar, Algeria, Australia, Egypt and Nigeria.
	Transportation system operator(s)	National Gas Transmission plc
	Gas distributor(s)	• Cadent • Scotia Gas Networks • Northern Gas Networks • Wales West Utilities
	Principal gas supplier(s)	• Centrica • E.ON • EDF Energy • RWE (nPower) • SSE • Scottish Power
	Interconnectors	Interconnections with: • Belgium • the Netherlands, ie the Balgzand and Bacton Line ("BBL") • Ireland from Moffat in Scotland, consisting of two pipelines, ie the Langeled Pipeline and the Scotland to Northern Ireland Pipeline

Overview of the renewable energy regime in 41 jurisdictions

This table has been collated using information compiled by the contributing authors for their corresponding jurisdictions and on the basis of information available at the time of writing.

ALBANIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	99% of energy generation comes from renewable sources. Pursuant to the National Action Plan for Renewable Energy Sources, the share of energy produced from renewable sources is set to increase to 45% of Albania's Gross Final Consumption of Energy by 2030. This is expected to be consumed in all sectors, including oil, gas, coal and imported electricity that is assumed to be of fossil origin (non-renewable).
	Key generators of renewable energy	Hydro Power Plants (public and private)
	Pre-qualifications	Provided by the Law on Renewable Energy Sources
FINANCIAL INCENTIVES	Feed-in tariffs	The following two feed-in tariffs exist: • existing HPPs up to 10MW, which is 7.77All/kWh • new HPPs up to 15MW, which is 9.37All/kWh There are also feed-in tariffs for: • photovoltaic (PV) plants with capacity of less than 2MW: €100/MWh • wind energy with capacity of less than 2MW: €76/MWh • margin contract support granted to the declared winner of the bidding procedure. Support under the margin contract (contract for difference) is based on a variable remuneration, calculated as the difference between the price at which the renewable energy generator has been declared winner in the competitive process of granting the aid (the fixed price) and the electricity market price (the reference price).
	Green certificates (name of the scheme)	Certificate of origin (upon the request of the renewable energy producer, the Albanian Energy Regulator must issue the certificate of origin for each unit of energy generated by the plant, after obtaining the construction permit for the renewable energy plant)
	Taxation	No specific taxation regime.
	Other	

AUSTRIA

OVERVIEW		
	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	The share of renewable energy in the total primary energy production in 2020 is listed in individual categories as follows: • Biogenic energy: 45.1% • Hydropower: 28.8% • Wind energy: 4.7% • Combustible waste: 5.6% • Ambient heat: 4.8% • Solar energy: 1.4% Austria set itself the target of having a 100% share of renewable energy generated by 2030.
	Key generators of renewable energy	• Verbund AG • Energie Burgenland AG • Wien Ernergie • EVN Naturkraft • WEB Windenergie AG • Tiroler Wasserkraft AG • KELAG • ÖkoEnergie
	Pre-qualifications	The general eligibility requirements for investment subsidies under the EAG vary depending on the technology. These are set by an ordinance. The EAG also stipulates some requirements, such as that the construction or expansion of PV on agriculturally used land or grassland leads to a reduction of the investment grant by 25%.

FINANCIAL INCENTIVES

Feed-in tariffs	The tariffs are laid down in the Feed-In Tariff Ordinance (*Ökostrom-Einspeisetarif-Verordnung*) ("ÖSET-VO 2018"). Until a new ÖSET-VO enters into force, the tariffs for the previous year will continue to be applied with a discount of 8% for PV-based plants, 1% for wind power, and 1% for other green electricity technologies. The following feed-in tariffs ("FiTs") for green electricity were set by the ÖSET-VO 2018 for 2019: • FiT for PV installations: 7.67 (€0.0767) cents/kWh • FiT for wind power plants: 8.12 (€0.0812) cents/kWh The FiTs for revitalised small hydropower plants with a bottleneck capacity or a standard capacity of at least 50%, provided they do not exceed 2MW, is set out under section 13(1) ÖSET-VO 2018, and are remunerated on a staggered basis according to kWh starting with the first 500GWh for 10.20cents/kWh up to over 7500GWh for 3.20cents/kWh. The FiTs for solid biomass also vary according to plant size between 10 cents and 21.56cents/kWh. The Act on the Expansion of Energy from Renewable Sources (*Erneuerbaren-Ausbau-Gesetz*) ("EAG") changes that remuneration system to the market premium model and will promote renewable energy production through a market premium subsidy. The market premium is calculated on the difference between the value to be applied ("*anzulegenden Wert*"), which is determined either by tender or by decree, and the reference market value, which is essentially the average value of the day-ahead market.
Green certificates (name of the scheme)	**Trading of guarantees of origin and green certificates** Guarantees of origin and Renewable Energy Certificates are instruments evidencing the origin of electricity generated from renewable energy sources. They can be traded in Austria independently or together with electrical energy in accordance with the provisions of the ERS Directive. In Austria, E-Control acts as an issuing body and is a member of the Association of Issuing Bodies.
Taxation	**Feed-in taxation** In principle, a levy of 1.5cents must be paid per kWh supplied. However, there is an allowance of 25GWh per year for electrical energy generated from renewable primary energy sources. Up to this limit, self-generated and self-consumed electricity is tax-free. In addition, there is a special regime for PV systems that provides for a tax exemption for self-generated and self-consumed electricity with no exemption limit. This applies to individuals, legal entities, and to producer groups ("*Erzeugungsgemeinschaften*"). The draft of the implementing regulation also provides that an exemption can be claimed if the energy is initially stored, as well as in the case of temporary feed-in to the public grid and later withdrawal for own consumption. End consumers incur the cost of green electricity subsidies (green electricity lump sum and green electricity subsidy contribution).
Other	N/A

BELGIUM

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy[1]	2020: Belgium's primary energy production in 2020 amounted to 155.06TWh, of which 62.8% came from nuclear energy, 29.9% from renewables and biofuels (including natural hydro, wind, solar, geothermal, solid and liquid biomass, biogas, renewable waste and heat pumps), 4.8% from non-renewable waste and 2.4% from other sources such as the recovery of heat from chemical processes and colliery gas from coal mines.
	
	Belgium produced 23.4TWh of gross electricity production from renewable energy in 2020, of which came:
	• Wind: 54.5%
	• Solar: 21.8%
	• Solid biofuels: 14.2%
	• Biogas: 4.3%
	• Renewable municipal waste: 3.9%
	• Natural hydro: 1.1%
	• Liquid biofuels: 0.1%
	2020 target: 13% renewable energy consumption; 10% renewable energy use in the transport section; 18% reduction in primary energy production.
	• Belgium reached 12.1% of its target for renewable energy consumption, making up the remaining 0.99% by purchasing quantities of energy from renewable sources in Finland, Denmark, and Lithuania. Belgium did meet its target of 10% (11.3%) of renewable energy to be used in the transport sector, however, was slightly above its indicative target of an 18% reduction in primary energy consumption.[2]
	2030 target:
	• United Nations 2030 Sustainable Development Goals: 18% renewable energy consumption by 2030.[3]
	• Belgium's National Energy and Climate Plan has set the following targets for 2030:[4]
	  ◦ reduce greenhouse gas emissions from the energy sector by 35% from 2005 levels;
	  ◦ reach 17.5% renewables in gross final energy consumption; and
	  ◦ significantly reduce energy demand.

Key generators of renewable energy	• Aspiravi • Belpower • Belwind • EDF Luminous • Electrabel • Electrawinds

FINANCIAL INCENTIVES

Feed-in tariffs	N/A (the system works to the contrary in that injection tariffs are due by decentralised electricity generators).
Green certificates (name of the scheme)	Federal level: federal GPCs for offshore wind parks and hydro installations, awarded in accordance with the green electricity generated. Flanders: GSCs (groene stroom certificaten) and CHPs (warmte kracht certificaten), awarded in accordance with the green electricity generated and corrected by a banding factor. The certificates can also be traded, and renewable energy generation technologies are eligible for a quota system. Brussels Capital Region: GPCs (groene stroom certificaten/certificats verts), awarded in accordance with the carbon dioxide ("CO_2") savings. Wallonia: GPCs (certificats verts), awarded in accordance with the CO_2 savings. Each licensed supplier must purchase a certain number of green certificates from the generators of renewable energy. Offshore wind: based on offshore GPCs. For offshore concessions with a financial close on/before 1 May 2014, the offshore GPCs can be sold to the Transmission System Operators ("TSO") at a fixed minimum price. For offshore concessions with a financial close after 1 May 2014, the price of offshore GPC is determined on the basis of the Levelised Cost of Energy ("LCOE"). Due to decreasing prices from other countries, a new Belgian support regime for offshore concessions has been approved by the European Commission, in which the price of the GPCs is also determined on the basis of LCOE.
Taxation	Contribution to the financing of the connection costs of offshore projects (Article 7,§2 Federal Electricity Act and Royal Decree of 8 June 2007). Surcharge on the federal GPCs to compensate the net costs between the purchase price and the market sale price (Article 7, §1 Federal Electricity Act and Royal Decree of 16 July 2002).
Other	Please see Belgium's 'recent developments in Energy Law and Policy – A Focus on Renewable Energy' article in this handbook for more details on Belgium's climate change and renewable energy policy, projects, and progress.

Endnotes

1. See Belgian Federal Ministry for Economy, SME, self-employed and energy, Energy Key Data (February 2022) www.economie.fgov.be/en/publication/energy-key-data-february-2022, pp.8, 21-9.
2. See Belgian Federal Ministry for Economy, SME, self-employed and energy, Energy Key Data (February 2022) www.economie.fgov.be/en/publication/energy-key-data-february-2022, p.16-9.
3. See www.energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/renewable-energy-targets_en and www.energy.ec.europa.eu/topics/renewable-energy/renewable-energy-directive-targets-and-rules/renewable-energy-directive_en.
4. See www.iea.org/countries/belgium.

BULGARIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Share of renewable energy in the gross final energy consumption (available data for 2019): 21.56% • Hydro: 47.8% • Biomass: 20.4% • Solar: 16.1% • Wind: 15.7% 2020 Target: 16% 2030 Target: 27.09%
	Key generators of renewable energy	NEK EAD (hydropower plants with installed capacity of 2,737MW) AES (wind power plant with installed capacity of 156MW) Enery (solar power plant Karadzhalovo with installed capacity of 60MW)
	Pre-qualifications	N/A
FINANCIAL INCENTIVES	Feed-in tariffs	**New projects:** feed-in tariffs apply only for small installations up to 30kW which are installed on the roofs and facades of buildings connected to the distribution networks. **Existing projects:** the feed-in tariffs for installations with capacity of 500kW and above were replaced with Contract for Premium. Such generators must sell electricity at the Bulgarian Electricity Exchange at market prices. The producers are compensated for the difference between the feed-in tariff and the market price with a premium paid by the Electricity System Security Fund.
	Green certificates (name of the scheme)	N/A
	Taxation	N/A
	Other	N/A

CROATIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	2020 target: 20% share of RES in gross final energy consumption (pursuant to the RED, Croatia has reached the 2020 target). The share of RES in total electricity generation in 2021 reached 23.1% (without large hydropower plants). The wind and hydropower accounted for over 63% of the total electricity generated from RES (14.5% and 48.5%, respectively). The remaining of electricity came from fossil fuels (28.5%), biomass (4.1%), biogas (2.8%), solar power (0.9%), and geothermal power (0.5%). At the end of 2021, Croatia reached a total installed capacity for electricity generation of 5,534MW (2,202MW of hydro power plants, 2,049MW of thermal power plants and 981MW of wind power plants), out of which 3,485MW (ie, 63%) are RES plants. 2030 target: 36.6% share of RES in gross final energy consumption (according to the Energy Development Strategy until 2030, NECP 2021-2030 and new RES Act of Croatia).
Key generators of renewable energy	• Senj wind farm with 156MW (ENERGIJA PROJEKT d.d.) • Krš Pađene wind farm with 142MW (C.E.M.P. d.o.o.) • Vrataruša wind farm with 42MW (Selan d.o.o.) • Velika Glava, Bubrig i Crni Vrh wind farm with 43MW (RP GLOBAL DANILO d.o.o.) • Zelengrad – Obrovac wind farm with 42MW (EKO-ENERGIJA d.o.o.) • Ogorje wind farm with 42MW (AIOLOS PROJEKT d.o.o.) • Rudine wind farm with 43.2MW (VJETROELEKTRANE RUDINE d.o.o.) • Lukovac wind farm with 48MW (VJETROELEKTRANA LUKOVAC d.o.o.) • ZD6 wind farm extension with 45MW (POŠTAK d.o.o.) • combined-cycle cogeneration unit L in TE TO Zagreb cogeneration plant with 100MW (HEP-Proizvodnja d.o.o.)
Pre-qualifications	In Croatia, it is not possible to participate in an auction for the award of market premiums simply with financial guarantees and an unmatured project. Only 'project holders' can participate in the public tender in accordance with the requirements set out in the RES Act and the RES Regulation. The 'project holder' is a project developer that has obtained an energy approval permit for construction of the production plant and which has been registered with the Croatian RES Register. The RES project needs to be even further advanced in terms of development and must be either 'ready-to-build', which means that the developer must have obtained a valid building permit, or alternatively, the project must have obtained a valid location permit. However, in line with EU state aid law, the RES projects that are already in the construction phase are not eligible to participate in the auction. The reconstruction of an existing production plant can also be considered as a new production plant if it meets certain statutory conditions.

CROATIA

Feed-in tariffs	Summary: From 1 July 2007 until 31 December 2015, Croatia had a system based on a mandatory purchase with a feed-in tariff ("FiT"). HROTE is obligated to purchase RES-electricity generated by eligible generators for an incentive price. Mechanism: The applicable incentive price for each RES or cogeneration plant is calculated by HROTE on the basis of number of pricing components set out in the tariff system applicable by the date of its commissioning (ie, statutory tariff system from 2007, 2012 or 2014). The FiP rate depends on the type of the RES or cogeneration plant and sources used for electricity generation and the installed capacity of the plant. The right to an incentive price is granted for a period of 14 years. Summary: Croatia has introduced a new auction-based support scheme (ie, Feed-In-Premium; "FIP") on the basis of the new Act on RES and High Efficiency Cogeneration (Zakon o obnovljivim izvorima energie i visokoučinkovitoj kogeneraciji)[1], with effect from 23 December 2021. In December 2021, the European Commission approved the €783 million Croatian state aid scheme to support production of electricity from RES and cogeneration plants. The new scheme will enable Croatia to support renewable electricity production from various technologies (wind, solar, hydro, biomass, biogas, and geothermal power plants). According to the RES Quotas Regulation, the total support quota for all groups of RES production plants until 2023 is set at 2,265MW, out of which 210MW for solar power plants with installed capacity of more than 50kW up to 500kW, 240MW for solar power plants with installed capacity of more than 500kW up to 10MW, 625MW for solar power plants with installed capacity of more than 10MW and 1,050MW for wind power plants with installed capacity of more than 3MW. Mechanism: Depending on availability of support quotas, HROTE will issue a call for tender at least once per year for the award of a guaranteed purchase price and once every three years for the award of market premiums. Market premium: Operators of RES or high-efficiency cogeneration plants, who have obtained the status of an eligible generator and have been selected as best bidder in a public tender carried out by HROTE, will be entitled to receive a market premium on top of the (reference) electricity market price, which they have sold on the market pursuant to the Croatian Electricity Market Act. The premium will be set through a competitive bidding process (auction). Notably, Croatia will have a double-sided sliding FIP in place, going along with components of a contract for difference ("CfD") mechanism: If the (reference) market price is below the CfD value (ie, strike price under the contract), the plant operator will receive this difference as a premium. If the (reference) market price is above the CfD strike price, the plant operator will be required to pay back the difference to HROTE. HROTE will have a pre-emptive right in purchase at the reference price. The premium will be paid out for a period of 12 years. Guaranteed purchase price: Operators of small RES or high-efficiency cogeneration plants with an installed capacity of up to 500kW will be entitled to conclude a power purchase agreement at a guaranteed purchase price, if they are selected as the best bidder in a public tender carried out by HROTE. The guaranteed purchase price will be paid out for a period of 12 years. The new implementing by-laws that will ensure full and effective implementation of new support schemes for RES and high-efficiency cogeneration plants are yet to be adopted (ie, regulation on support quota for RES and cogeneration plants until 2030).

Green certificates (name of the scheme)	Croatia has introduced the Guarantees of Origin ("GO") and electricity disclosure obligation, which is consistent with the requirements set out in the RES Directive. A GO issued within the Croatian system is an electronic certificate for the purpose of proving to final customers the share of or quantity of RES in an energy supplier's energy mix. On request of the eligible generator, who does not qualify for RES support system, GOs can be issued and traded on the market independently of the electricity generated. HROTE is entitled to issue GOs for delivered energy within RES support system and guaranteed purchase price system and to sell these GOs. HROTE has been designated as a single competent body for issuing GOs in Croatia pursuant to the Regulation on Establishing the System of Guarantees of Origin of Electricity (*Uredba o uspostavi sustava jamstava podrijetla električne energije*)[2] and the Rules on Using the Registry of Guarantees of Origin of Electricity (*Pravila o korištenju registra jamstava podrijetla električne energije*)[3]. The Registry of GO, which became fully operational in February 2015, implements a system for issuing, transferring, and cancelling GOs for electricity generated from RES and high-efficiency cogeneration. By end of 20220, eight six energy suppliers, three two energy traders and five 17 electricity producers (ie, a total of 2516 users) have been registered with the Register of GO maintained by HROTE. The Methodology for Determining Origin of Electricity (*Metodologija utvrđivanja podrijetla električne energije*)[4] with effect from 21 November 2014, imposed obligations on suppliers regarding the disclosure of the origin of electricity to final customers and duties of HROTE as the market operator, the DSO, and the TSO regarding the residual mix calculation.
Taxation	N/A
Other	N/A

Endnotes

1. Official Gazette of the RoC 'Narodne Novine' nos. 138/21.
2. Official Gazette of the RoC 'Narodne Novine' nos. 84/13, 20/14, 108/15 and 55/19.
3. HROTE of 12 July 2019.
4. Official Gazette of the RoC 'Narodne Novine' nos. 133/14 and 127/19.

CYPRUS

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Renewable energy source ("RES") total based on 2020 figures: 17.08% • Solar: 36.67% • Biomass: 24.86% • Biogas: 3.72% • Geothermal: 0.56% • Heat pumps: 16.95% • Wind: 7.48% • Biofuels (biodiesel): 9.75% RES Target 2030: 23%
	Key generators of renewable energy	Solar and biomass
	Pre-qualifications	The eligibility conditions differ per scheme launched and are published by the Ministry of Energy and/or the RES Fund.
FINANCIAL INCENTIVES	Feed-in tariffs	Arrangements vary depending on the support scheme under which each RES producer is operating. Such schemes are no longer available and new entrants must participate in the transitory market and, in due course, the competitive wholesale market for electricity.
	Green certificates (name of the scheme)	Certificates of Guarantee of Origin (*Πιστοποιητικά Εγγύησης Προέλευσης Ηλεκτρικής Ενέργειας που παράγεται από ΑΠΕ*) administered and issued by the Cyprus Transmission System Operator (CTSO).
	Taxation	• A levy on electricity consumption is payable by all persons connected to the distribution system (with a reduced rate applicable to vulnerable household consumers). This is the major source of funds for the RES Fund which provides grants and subsidies for investment or activities promoting RES and energy conservation. • Annual circulation fees payable in respect of motor vehicles are determined taking into account carbon dioxide (CO_2) emissions.
	Other	N/A

CZECH

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Percentage of energy generation from RES: approx. 13.56% 2020 RES target: 10% 2030 RES target: 22% Breakdown of RES: • Biomass: 65% • Biofuel: 19% • Hydro: 4% • Solar: 4% • Waste: 2% • Wind: 1%
	Key generators of renewable energy	Biomass and biofuel
	Pre-qualifications	In order to qualify for the current operational support scheme, the producers must comply with requirements of SESA and Energy Act, such as: • obtain an electricity generating licence from the ERO; • conclude a grid connection agreement with the respective DSO; and • fulfil a number of technical and economical parameters set out in the decrees implementing the SESA.
FINANCIAL INCENTIVES	Feed-in tariffs	Yes Under the feed-in tariff scheme, producers sell electricity to obligatory purchasers (regional DSOs) at a fixed minimum price.
	Green certificates (name of the scheme)	Yes (green bonus) Under the green bonus scheme, producers sell electricity on the electricity market for the market price and are entitled to receive an additional fixed amount from the market operator.
	Taxation	No
	Other	Upon fulfilling predefined conditions, investors may apply for investment subsidies for new RES installations from incentive programs such as the Modernization Fund and the Operational Program Technology and Application for Competitiveness.

DENMARK

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	RES total based on 2020 figures: 29.8%* • Wind: 32% • Biomass: 44% • Solar: 4% • Hydro and geothermal: 1% • Biogas: 12% • Heat pumps: 7% RES Target 2030: 55%
	Key generators of renewable energy	Wind and biomass
	Pre-qualifications	The eligibility conditions differ for the support available under each scheme launched and are published by the DEA.
FINANCIAL INCENTIVES	Feed-in tariffs	Electricity: the current transitional arrangement is covered by government grants until 1 January 2023. From then, renewable energy installations will pay a greater share of the costs imposed on the grid; the scheme has yet to be established but is expected to be based on a standardised cost principle (as opposed to actual costs).
	Green certificates (name of the scheme)	Certificate of origin (*Oprindelsesgarantier*) administered and issued by Energinet
	Taxation	Taxation is based on a 'carrot and stick' approach: • easing of levies on electricity for certain uses • reduction of registration taxes for green cars • certain elective tax regimes for owner of RE installations • CO_2 taxes
	Other	N/A

ESTONIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2020 Target for renewable energy	The EU target for Estonia's end consumption of energy from renewable resources was 25%, which Estonia achieved in 2011. In 2019, 28% of electricity generated originated from renewable sources with biomass and wind as main sources followed by waste to energy, biogas and hydro.[1]
Key generators of renewable energy	• Eesti Energia group • Fortum group • Utilitas group
Pre-qualifications	As a rule, only companies registered in Estonia are allowed to participate in auctions. Additionally, companies registered in the EEA may participate in auctions, but only if the country of their incorporation permits companies registered in Estonia to participate in similar auctions held in that country. Companies can participate in auctions with generation installations which commence production for the first time only after the results of the auction have been announced in order to ensure the incentive effect of the state aid.

ESTONIA

FINANCIAL INCENTIVES

Feed-in tariffs	The support scheme differentiates between existing producers and new producers. The existing producers are entitled to receive a fixed feed-in premium ("FIP") as described below, whereas new producers can receive support only when Estonia needs additional renewable energy capacities in order to meet the target for the share of electricity generated from renewable energy sources and arranges auctions for the development of new electricity generation installations. An existing producer is entitled to receive support in the form of FIP from the TSO for each kWh of electricity generated: (i) from a renewable energy source with a generation installation the net capacity of which does not exceed 125MW at the rate of €0.0537/kWh; (ii) from biomass in a co-generation plant at the rate of €0.0537/kWh; (iii) from waste, peat or retort gas in an efficient co-generation plant at the rate of €0.032/kWh; or (iv) in an efficient co-generation plant the net capacity of which does not exceed 10MW at the rate of €0.032/kWh. Only electricity supplied to the network or to a customer via a direct line qualifies for the support, ie the generation installation's own consumption is not subsidised. The support is paid by the TSO in addition to the price received by the producer upon sale of the electricity. The support is paid for a period of 12 years following commencement of production. Certain restrictions apply, eg in the case of wind energy, a cap of 600GWh per calendar year applies to wind energy producers qualified to receive the FIP; facilities using biomass will qualify for the subsidy only if they use co-generation processes and not if they use condensation processes. In 2018, granting of renewable energy support in the form of FIP was replaced with the system of auctions where the winner is the producer offering the lowest contract for difference ("CfD"). Based on the results of the auction the winning producer will have the right to cover the difference between the monthly market price and the price established at auction in the production volume offered in the auction in the form of return of negative balance. The CfD as applied in Estonia means that producers are not obliged to return the surplus if the market price exceeds the auction price. No support is allocated when the electricity price on the power exchange is lower than or equal to zero.
Green certificates (name of the scheme)	The TSO issues certificates of origin, which certify that the electricity is generated from renewable energy sources or in an efficient co-generation process.
Taxation	Taxation of electricity in general is based on excise levied on the consumption of electricity at the regular rate of €4.47/MWh and reduced rate of €0.5/MWh applicable to qualifying electro-intensive undertakings. From 1 May 2020 through to April 2022 the regular rate has been reduced to €1/MWh due to COVID 19 pandemic. There are no separate tax incentives for electricity generated from renewable resources, however, generation of electricity from renewable resources is not subject to the environmental charges that are applied to non-renewable electricity generation (eg charges for emissions such as CO_2).
Other	N/A

Endnotes

1. See Statistics Estonia article www.stat.ee/en/uudised/eesti-elektritootmine-liigub-keskkonnasobralikus-suunas

FINLAND

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Renewable energy sources ("RES") accounted for 42% of the total energy consumption in 2021. RES and their respective shares of the total energy consumption in 2021 were: • Hydropower: 4% • Wind power: 2% • Wood fuels: 30% The renewable energy target for 2030 is 51%.
Key generators of renewable energy	Pulp and paper industry, hydropower companies, wind power companies and other energy companies. The major players include: • Fortum Oyj • Kemijoki Oy • Pohjolan Voima Oy • EPV Energy Oy • The forest industry
Pre-qualifications	Electricity may only be marketed as from renewable sources when there is a guarantee of origin ("GO"). GOs are issued by Fingrid, the transmission system operator (TSO) in Finland. Additionally, there are a number of subsidies that may be granted for renewable energy. Please see the section entitled 'Financial incentives' below for further information.

FINLAND

Feed-in tariffs	A state funded subsidy scheme has been established through the Act on Production Subsidy for Electricity Produced from Renewable Energy Resources ("PSRESA"), which contains provisions on production subsidy (feed-in tariff ("FiT")) to be paid for electricity generation based on wind power, biogas and wood-based fuels. The wind power quota (2,500MVA) was reached and the last wind power plant was approved into the scheme on 4 January 2018. In late 2018, the FiP was closed also for generation using biogas and wood-based fuels. In addition, the FiP was closed for generation using forest chips in March 2021. Electricity generators accepted in the scheme may receive a subsidy for a period of up to 12 years. The FiP is the guaranteed price (€83.50) reduced by the three-month average market price of electricity in the area where the plant is located. However, if the three-month average price is less than €30, the FiP is the guaranteed price reduced by €30/MWh. The FiP paid for electricity generated in small wood-fuelled combined heat and power ("CHP") plants and biogas powered CHP plants may under certain conditions be increased by a heat premium that is €20/MWh for the former and €50/MWh for the latter. The FiP for electricity generated with wood chips is different from the above as it fluctuates on the basis of a calculation methodology involving the market price of an EU Emission Trading Scheme (EU ETS) emission allowance, the price of peat and the level of national taxation on peat. In 2018, the PSRESA was amended to include a new technology neutral subsidy scheme for a transition period in 2018 to 2020. Wind power, CHP, biogas, solar power and wave power plants located in Finland can be accepted into the scheme. The first, and possibly only auction round for the new scheme was open for bidding between 15 November and 31 December 2018. Under the scheme, electricity generators can submit bids for the level of support ("premium") they require to generate a defined annual amount of renewable electricity. The premium decreases or is not paid at all if the price that the electricity generator has bid is obtained without the premium at market price. The tendering scheme will accommodate 1.4TWh of annual generation.
Green certificates (name of the scheme)	There is no national scheme on green certificates in Finland. However, energy users may purchase green certificates from trading markets or buy their electricity through various green electricity schemes.
Taxation	Taxation of electricity is based on excise taxes levied on the consumption of electricity. There are no tax exemptions or reliefs for electricity generated from RES. Fuels consumed in the generation of electricity are tax exempt; fuels consumed in heat production are subject to tax. Regarding CHP plants, this means that the decisive factor in the taxation is what the plants produce during a tax period. In 2011, the taxes for consumption of fossil fuels and peat were increased in order to make carbon dioxide (CO_2) neutral energy sources more competitive. Additionally, the energy content of and the greenhouse gas (GHG) emissions from fuels were better taken into account in fuel taxation. In 2019, the Act Banning the Use of Coal for energy generation entered into force. Coal based power and heating will be banned as of 1 May 2029. In 2020, the Act on Excise Duty on Liquid Fuels was amended to further increase taxation of fossil fuels. Energy intensive industry benefits from a significant tax return when the total excise duties for electricity, coal, LNG, tall oil, fuel peat, light fuel oil, heavy fuel oil and biofuel paid exceed a certain threshold. This reduces the impact of the tax increases. The tax return paid for fuel is currently being phased out so that companies will no longer be entitled to a refund from 2025.

Other	Investment subsidies Depending on the size of the investment, either the Ministry of Economic Affairs and Employment or government organization Business Finland may grant energy subsidies for investments made in: • renewable energy • improvements in energy efficiency or in the efficiency of energy production or consumption • promoting the transition towards a low-carbon energy system. In 2019, investment aid for new energy technology and large demonstration projects was introduced as part of the energy subsidy scheme. The decisions to grant energy aid are based on the investment costs of the project and the novelty value of the technology used in the project. The investment costs are required to be at least €5 million. The application period ended on 31 August 2022. The Ministry of Economic Affairs and Employment has prepared a new energy and climate strategy, which was submitted to Parliament by the Finnish Government in June 2022. The strategy includes additional funding for new technologies, domestic wood chips and the hydrogen economy. The Ministry of Agriculture and Forestry grants subsidies for the harvesting and chipping of energy wood. In June 2022, the Act on Electrification Subsidies for Energy-Intensive Industries entered into force. The objective of the subsidies is to compensate industry for the indirect costs caused by emissions trading that affect the price of electricity. At least 50% of the subsidy must be used to develop measures that promote carbon neutrality. Under a current government proposal, the state-owned company "Ilmastorahasto Oy" (Climate Fund) would be given the opportunity to grant state subsidies for emission-reduction projects that would otherwise not be implemented.

FRANCE

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Electricity generation in 2022 amounted to 445.2TWh including 24% from renewable sources' generation, and more precisely: (i) hydraulic: 11% (49.6TWh); (ii) wind: 9% (38.1TWh); (iii) photovoltaic: 4% (18.6TWh); (iv) renewable thermal and waste: 2% (10.6TWh). In 2022, a record volume of renewable installations was commissioned (5GW). The use of renewable energy must cover 32% of the French gross final electricity consumption and 40% of the electricity generation within 2030.
Key generators of renewable energy	EDF/EDF EN, ENGIE, Neoen, GreenYellow, Tenergie, CNR, Boralex Other main solar producers include: Amarenco, Akuo Energy, TotalEnergies, Urbasolar, Arkolia, Silversun, Smart Energies, Acteam EnR, Enoé Energie, Technique Solaire, Reden solar, Apex Energies, Générale du Solaire, Solveo, Valeco, Arkolia, Reservoir Sun, Terre et Lac, Sunergis, Cap Sud, Acteam EnR, Albioma.
Pre-qualifications	There is an open window-system for certain limited cases of renewable energy projects, listed by ministerial order (such as solar plants on buildings under 500kW, some biogas projects under 500kW, plants using the hydraulic energy of lakes under 500kW, etc). For the other projects, there are two types of tender procedures that can be used by the French ministry of energy: • The auctions process, especially for onshore wind farms, solar plants and hydropower projects; and • The competitive dialogue (in French "*dialogue concurrentiel*") for offshore wind farms projects. In both proceedings the technical and financial capacities of the candidates are examined by the French energy regulatory authority (CRE), according to the evaluation methods defined in the bidding documentation.

FINANCIAL INCENTIVES

Feed-in tariffs	The French support mechanism for the renewable energy sector used to be solely based on feed-in tariffs. Currently, the scope of the feed-in tariff mechanism has been reduced to smaller scale facilities only, in accordance with the EU Energy Guidelines, and it continues to be allocated through two different mechanisms: ie, ministerial orders and tender procedures. In addition to the feed-in-tariff mechanism there is a feed-in-premium system (in French "*complément de remuneration*"). The premium system has now been implemented as the main support regime for renewable energy projects in accordance with the EU Guidelines. Premium contracts are allocated through either: (i) the tender procedures (auctions process or competitive dialogue) or (ii) in more limited cases, through the open window-system. The French contract for difference ("CfD") support regime provides for a cap protecting renewable energy producers in case of negative premiums. This cap was removed by an Amended Finance Law for 2022, and the cap removal applies from the 1 January 2022 until the end of the CfD providing such feed-in-premium. It must be stressed that renewable energy producers are not allowed to benefit at the same time from the purchase obligation (ie, feed-in tariff) or premium mechanism, if they do, the corresponding contracts shall be terminated and the amount of the corresponding purchase price or premium shall be reimbursed.
Green certificates (name of the scheme)	Electricity producers may apply and be granted a renewable energy guarantee of origin (REGO) attesting that the electricity they produce comes from renewable sources of energy. Each certificate issued is attached to the production of 1MW of energy. These REGOs may subsequently be sold to electricity suppliers wishing to warrant to their clients that a part of the electricity supplied to them comes from renewable sources or cogeneration. It must be stressed that renewable energy projects for which a REGO has been issued by the producer are not eligible to either the feed-in tariff mechanism or the premium mechanism.
Taxation	The main tax incentives/mechanism include: • A tax mechanism on inframarginal market revenues of electricity producers has been implemented by the French Finance Law for 2023. The amount of this tax is equal to a fraction of the operator's market revenues exceeding a determined threshold, set at different levels depending on the production technologies concerned. As of today, only the revenues generated by the production of electricity between 1 July 2022 and 31 December 2023 are subject to this tax contribution. • In addition, a tax on electricity is due by suppliers based on the quantity of electricity supplied to their final clients/consumers (in French "*accise sur l'électricité*"). Such tax has been reduced from 1 February 2022 to 31 January 2024 (reduction of the rates applicable as of 1 January 2022), within the limit of the minima fixed by the directive on energy taxation, ie EUR0.5/MWh for professionals and EUR1/MWh for individuals. The applicable tariffs on electricity resulting from this reduction are fixed by article 64 of the Finance Law for 2023. • There is also a tax reduction or exemption from land tax in respect of energy saving investments for purchasing equipment using renewable energy.
Other	N/A

GERMANY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Renewable energy sources: 46.3% Wind power: 24.1% Biomass: 5.8% Solar: 10.6% Water power: 3.2% Other renewable: 2.6% 2030 target: 80%
	Key generators of renewable energy	Wind power; solar, biomas
	Pre-qualifications	Procedures differ for the different energy sources General factors: provision of security, the form of energy, bid quantity in kilowatts and bid value in cents per kilowatt-hour for which the bid is submitted
FINANCIAL INCENTIVES	Feed-in tariffs	There are three options for the operators of renewable energy plants to receive EEG funding: • Market premium (*Marktprämie*) • Feed-in tariffs (*Einspeisevergütung*) • Tenant electricity surcharge (*Mieterstromzuschlag*)
	Green certificates (name of the scheme)	There are two emission trading systems applicable in German: • Federal Greenhouse Gas Emissions Trading Act • Fuel Emissions Trading Act
	Taxation	In principle, an electricity tax is levied, but a number of concessions and exemptions are provided for. The tax concessions stem from, among others, the direct implementation of requirements of European Union law, legislators' efforts to ensure the competitiveness of the German economy, environmental policy, and so on.
	Other	N/A

GREECE

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2021, renewable energy source generation ("RES") (including hydro) reached 22.31TWh, accounting for about 41.5% of the total energy generated in Greece. The breakdown per RES technology for the year 2021 was: • Wind: 48% of the total RES generation or 10.72TWh • Hydro: 26.5% or 5.93TWh • Photovoltaic ("PV") (including rooftop PVs): 23.2% or 5.18TWh • Biomass: 2.3% or 490GWh **2030 target**: 70% share of energy from renewable sources (as a percentage of Greece's gross final energy consumption).
Key generators of renewable energy	• Rokas Renewables (Iberdrola Group) • Terna Energy • Ellaktor • CF Ventus • ITA Group • EDF • Eltech Wind • PPC Renewables • EREN Hellas • ENTEKA • Quest • Enel Green Power • Eunice • Protergia • HELPE Renewables • Gamesa Hellas
Pre-qualifications	The construction and operation of a RES plant requires the fulfilment of the relevant permitting process, which requires the issuance of the following administrative licences: • Producer's Certificate • Environmental Licence • Installation Licence • Building Licence • Operation Licence RES stations with an installed capacity of under 1MW are exempt from the obligation to obtain a Producer's Certificate, Installation License and Operation Licence.

GREECE

FINANCIAL INCENTIVES

Feed-in tariffs	The Greek State ("the State") replaced the previously applicable feed-in tariff ("FiT") scheme with a sliding Feed-in Premium ("FiP") scheme, in compliance with European directives and principles relating to state aid in the energy sector for the period 2014 to 2020 and, consequently, 2021 to 2025 (EEAG). The FiP scheme is an operating aid mechanism intended to incentivise the gradual market integration of RES. Therefore, the main two principles that characterise such a scheme are: • the adaptation of a new market-based RES tariff mechanism, reflecting the decreased cost of RES technologies and therefore, enabling the gradual integration of RES in the market; and • the active participation of RES generators in the wholesale electricity market by bearing market risks linked to short term price fluctuations and balancing responsibilities.
Green certificates (name of the scheme)	Guarantees of origin scheme: The RES Operator & Guarantees of Origin ("DAPEEP" as per its Greek acronym) is the competent Issuing Authority of Guarantees of Origin Certificates for the interconnected system and network in Greece.
Taxation	The National Development Law (ie Law no. 4887/2022) which covers specific categories of RES projects (such as hydroelectric projects of an installed capacity of up to 15MW) as well as the Strategic Investments Framework (ie Law no. 4864/2021) provide for tax breaks of up to 100% of the maximum allowable amount of aid. The relevant tax relief comprises exemption from payment of income tax on pre-tax profits that result from any and all of the enterprise's activities. In addition, both of these laws provide a tax stabilisation incentive, while the Strategic Investments Framework allows for the over-depreciation of fixed assets related to the investment.
Other	Other financial instruments for the promotion of RES in Greece (with the exception of several types of RES), under the National Development Law and/or Strategic Investments Framework are: • Subsidies: gratis (without repayment) payment by the State of a sum of money to cover part of the subsidised expenditure of the investment; • Leasing subsidies: includes payment by the State of a portion of the instalments paid under a leasing agreement executed to acquire new machinery and/or other equipment; and • State aid: covering the costs of the employment positions created, namely the wage costs of employment positions linked to the investment for which no other State aid scheme has been received.

HUNGARY

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Breakdown of electricity generation from renewable energy sources ("RES") in 2020 is listed as follows: • Biomass: 4.37% • Biogas, landfill gas, sewage gas: 0.89% • Wind: 1.88% • Hydropower: 0.70% • Solar: 6.94% • Biodegradable waste: 0.85% • Waste: 0.73% • Other (geothermal, artificial gases): 0.86% Together: 17.22% Hungary has set the target of having a 10.9% share of renewable energy in electricity generation by 2020. The relevant targets set out in the National Energy Strategy for 2030 are as follows: • Increase the share of carbon neutral technologies (including nuclear energy) within the national electricity generation mix to 90% • Increase the gross inbuilt photovoltaic (solar) electricity generation capacity to 6,000MW
Key generators of renewable energy	• MVM • MET • E.ON • Greencells • Optimum Solar • Iberdrola
Pre-qualifications	As a general rule, Hungary's contract for difference (CfD) or premium based renewable energy support scheme ("METÁR Regime" or "Premium System") is technologically neutral; it is open to any non-fossil and non-nuclear energy sources for generating solar, wind, geothermal, wave, tidal, hydropower and biomass energy. This includes energy sources produced directly or indirectly from biogases (landfill gas, sewage treatment plant gas and combustible gases produced from other organic substances). However, the installation of wind turbines is currently not possible due to administrative measures, ie the relevant legislation (most notably Act LXXXVI of 2007 on Electricity and the related 33/2009. (VI.30.) KHEM Decree on the Requirements for the Installation of Wind Power Plant Capacities) does not enable developers to construct new wind power plants. A new tender in the Premium System is announced twice a year, each time with slightly modified terms. In the last tender (March 2022), the minimum capacity of eligible power plants was 5MW, while the maximum was 50MW, and the bid on the supported price was capped at HUF25,000/MWh (about €65/MWh). Winning projects were also required to install storage capacities equalling at least 10% of the installed capacity.

HUNGARY

FINANCIAL INCENTIVES

Feed-in tariffs	With respect to most RES Generators currently operational and under construction in Hungary, the primary incentive is the mandatory offtake or feed-in-tariff regime ("FiT Regime"). Under this FiT Regime, the entitled RES Generators ("FiT Generators") are entitled to sell the generated electricity at predetermined regulated prices for a certain period of time and up to a certain quantity as determined by HEA. FiT Generators must not sell electricity to any third party while participating in the FiT Regime. The detailed rules of the FiT Regimes are provided by Government Decree 389/2007 (XII. 23.). The support system for RES Generators has been amended significantly as changes in the relevant EU legislation took effect. As a result, an application for participating in the FiT Regime could only be submitted before 31 December 2016. On 1 January 2017, a new METÁR Regime or Premium System was introduced. RES Generators under METÁR are exposed to a more market-based regime whereby RES Generators are selling the generated electricity on the free market (eg on the Hungarian Power Exchange ("HUPX") or under a corporate Power Purchase Agreement); however, subject to the outcome of regular open tenders, a certain surplus (premium) may be awarded to RES Generators as a state subsidy to ensure return on investment. Notwithstanding the above, the FiT Regime continues to apply for FiT Generators, ie those RES Power Plants that submitted their application for subsidy before 31 December 2016 and have been awarded an entitlement to participate in the FiT Regime.
Green certificates (name of the scheme)	RES Generators benefit from the system of tradable guarantees of origin ("Guarantees") as well. The purpose of the Guarantees is to certify towards the buyers of electricity that the given volume of electricity originates from RES. Guarantees issued in other EEA member states also maintaining a system of tradable Guarantees are mutually accepted Before 31 December 2021, FiT Generators could request the HEA to issue one Guarantee for each MWh of electricity generated by it from renewable sources. The awarded Guarantees were then allocated to an electronic account of the operator, and were tradable instruments, subject to market demand. Despite this, tradable Guarantees have not developed into a significant market in Hungary. After the amendment of the Electricity Act and the Guarantees of Origin Decree entered into force on 1 January 2022, Guarantees of FiT Generators are no longer given to the generators, but must be sold by MAVIR (the only Hungarian Transmission System Operator (TSO)) at auction, more precisely on the Hungarian Guarantees of Origin market ("HUPX GO") which has been operated by the HUPX since June 2022. The incomes from the sale of such Guarantees will be contributed to the fund financing the FiT Regime.

FINANCIAL INCENTIVES (continued)

Taxation	Financing of the FiT Regime: In order to maintain the FiT Regime, a specific fund has been introduced through legislation. The costs of the FiT Regime are financed by other balance group operators (electricity traders) in the ratio of electricity sold to end-users in their balance group not licensed for universal service provision. The financial burden of this fund is carried by free market end users (ie primarily by industrial and commercial users). The incomes from the sale of Guarantees are also to be contributed to the fund financing the FiT Regime. Robin Hood Tax: The taxpayers of the so-called Robin Hood Tax are the energy suppliers including, among others, electricity traders, electricity distribution system operators (DSO) and electricity generators. However, licensed electricity generators operating a power plant unit with a nominal capacity not exceeding 50MW that are participating, at least partially, in the FiT Regime or METÁR Regime, cannot qualify as energy suppliers under the Robin Hood Tax Act and, therefore, are not subject to the Robin Hood Tax. Owners of power plants below a capacity of 0.5MW (AC) do not qualify as 'energy suppliers' and are not subject to the Robin Hood Tax either. The applicable tax base is basically the positive accounting pre-tax profit (similar to those applicable in case of the corporate income tax) and the applicable tax rate is 31%.
Other	N/A

ICELAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Installed capacity in power plants: • Hydro 71.61%: 2.215MW • Geothermal 25.83%: 799MW • Fuel 2.49%: 77MW • Wind 0.06%: 2MW Electricity generation: • Hydro 70.38%: 13.804GWh • Geothermal 29.58%: 5.802GWh • Fuel 0.01%: 2GWh • Wind 0.03%: 6GWh 2030 Target for renewable energy: • Implementing the goals of the Paris Agreement with a 55% total reduction in emissions between 1990 and 2030. • Independent national target of a 55% reduction in emissions between 2005 and 2030. • 40% share of renewable energy in transport by 2030. • 10% share of renewable energy in sea-related activities by 2030. • Carbon neutral Iceland in 2040 and full energy transition and independence from fossil fuels by 2050.
	Key generators of renewable energy	• Landsvirkjun • ON Power • HS Orka • Orkusalan • Fallorka • Westfjord Power Company
	Pre-qualifications	N/A
FINANCIAL INCENTIVES	Feed-in tariffs	N/A
	Green certificates (name of the scheme)	EECS Scheme certificates issued by Landsnet in accordance with the Renewable Energy Directive.
	Taxation	N/A
	Other	N/A

IRELAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2021, 10.44TWh of renewable electricity was generated (34.8% of electricity generation), which comprised of: • wind: 28% • solar: 1% • hydro: 2% • biofuels and waste: 3.8% **2030 Target:** overall RES: 34.1%
	Key generators of renewable energy	• ESB • Brookfield Renewable • Energia Renewables (Viridian Group) • SSE Airtricity
	Pre-qualifications	Depending on the auction.
FINANCIAL INCENTIVES	Feed-in tariffs	The Renewable Electricity Support Scheme ("RESS") is allocated by way of a series of auctions (to date, RESS 1, RESS 2 and RESS 3). The requirements for eligibility include that the project must be a new project, must use one of the eligible technologies and be of a minimum size of 500kW. Offshore wind is not eligible to participate in RESS auctions but can participate in the ORESS (offshore renewable energy support scheme) auctions.
	Green certificates (name of the scheme)	N/A
	Taxation	Accelerated capital allowance, which is a tax incentive scheme that promotes investment in energy efficient products and equipment. Employment and incentive investment ("EII") scheme, which is designed to promote the creation of employment and research and development. The EII scheme provides tax relief for eligible individuals who invest in certain qualifying small and medium sized trading companies. Tax relief for corporate equity investments in certain renewable energy projects. A deduction from a company's profits is allowable for its direct investment in new ordinary shares in a qualifying renewable energy project. Solid fuel carbon tax ("SFCT"), which is an excise duty that applies to solid fuel (coal and peat) supplied in Ireland. As of May 2023, coal is taxed at €127.74 per tonne and peat briquettes at €88.93 per tonne.
	Other	The Sustainable Energy Authority of Ireland ("SEAI") supports projects through the National Energy Research Development and Demonstration (RD&D) Funding Programme. The programme invests in innovative energy research and development projects through various supports, including: • SEAI National Energy RD&D Funding Programme • Ocean Energy European Research Area Network Cofund • Horizon 2020

ISRAEL

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Renewable energy sources ("RES") constitute about 8.5% of the annual consumption in Israel. This is expected to reach 30% by the end of 2030, with a corresponding intermediate target of 20% by 2025. The current RE annual generation capacity is divided according to the following internal breakdown: • Solar (photovoltaic ("PV")/Thermo-Solar): 95% • Wind: 2% • Biogas (including biomass): 1.8% • Hydroelectric: 0.5%
Key generators of renewable energy	As of mid-2022 there are 10 solar-powered IPPs connected to the ultra-high and extra-high voltage Transmission Network, which include: • Megalim Solar Power Ltd. (136MW) (Thermo-Solar) • Negev Energy Ashalim Thermo-solar (136MW) • Ashalim Sun PV Limited (30MW) • Solar Park Timnah Ltd. (60MW) • Eshkol Havazelet - Halutzyut Enlight Limited Partnership (55MW) • Zmorot Solar Park Limited (50.064MW) • Ketura Solar, Limited Partnership (40MW) • Energix Renewable Energies Limited (37.5MW) • Sneor Zeelim Limited Partnership (120MW)
Pre-qualifications	• Participation in competitive procedures published by the EA in order to receive a quota; the competition is on the Feed-in tariffs ("FiTs"). • An electricity production licence granted by the EA is required for large renewable energy facilities above 16MW (licences of over 100MW need additional approval from the Minister of Energy). • Possession of/rights to land for the construction of the facilities; planning permits may be required for facilities over 50MW. • Ability to connect to the electricity grid. • Financial capacity: An applicant may be requested to provide financial statements. A minimum of 20% equity is required for funding the construction of licensed electricity production facilities, to be injected upon financial closing.

FINANCIAL INCENTIVES

Feed-in tariffs	From 2017 to 2021, the EA published several competitive procedures focusing mainly on small-medium PV facilities and PV facilities with storage capability (with a capacity ranging from 51kW to 10MW) connected to the distribution network, resulting in decreasing FiP rates. In Q3 2018, the EA published for PV installations with a capacity exceeding 10MW its first tender for large PV systems to be connected to the extra-high and ultra-high transmission network. Winners were announced in May 2019 at record low rates ranging from NIS0.1444 to NIS0.1668kW/h (about US$0.0443kW/h to US$0.0512kW/h, respectively). As a result of the above tender processes, the FiP rates in the solar sector are subject to competition and are steadily declining. Wind energy: A series of Government decisions of 2011 and 2014 established an accumulated quota of up to 730MW of wind-farm facilities with a base FiT-linked to the index for turbine prices (WTPI – Class III), among others. In 2017 and 2020, the EA adjusted the wind FiTs to reflect a more conservative wind speed level. The tariff is, among other things, linked to last three quotas of the consumer price index, the US dollar, and the base index for turbine prices (WTPI – Class III). The FiP is guaranteed for a period of 20 years.
Green certificates (name of the scheme)	N/A
Taxation	In December 2016, the Israeli Parliament enacted the Law for Encouragement of Investments in Renewable Energies (Tax Incentives for Production of Electricity from Renewable Energy) (2016) approving tax reductions to private households producing electricity with RES (ie an income tax exemption up to NIS24,200 (about €6,100)).
Other	N/A

ITALY

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	The renewable energy sources ("RES") contribution to the total gross final generation is 38.1%. Electricity generation from renewable sources is: • Wind: 18.8TWh • Solar: 24.9TWh • Biomass: 19.6TWh • Hydroelectric: 47.6TWh • Thermal and geothermic: 4.77GW The 2030 target is a share of 17% energy from renewable sources in gross final consumption of energy; Italy reached 17.3% in 2016.
Key generators of renewable energy	• ENEL S.p.A. • ENI S.p.A. • Edison S.p.A. • A2A S.p.A. • EPH S.p.A. • Iren S.p.A.
Pre-qualifications	Procedures differ for the different energy sources. General factors: new plants or complete refurbishment, size of the plant, kind of site (whether industrial, agricultural etc), bid submitted in the context of the tender.

ITALY

Feed-in tariffs	The available mechanisms supporting renewable electricity are subject to the entering and execution of a contract with GSE, which is regulated under the Italian Civil Code. The feed-in tariff ("FiT") mechanisms applied to existing RES plants will be discontinued for newly developed plants, although they will be effective for existing incentivised plants until the termination of the remaining incentive period. The RES-1 Decree replaced the FiT mechanisms by setting out a fixed FiT paid out for the entirety of the corresponding plant's utility period. However, the RES-1 Decree does not apply to offshore windfarms, biogas plants, biomass and bioliquid plants, oceanic source and thermodynamic solar plants. There are no incentives currently envisaged for any new plants fuelled by these sources; however, a specific decree is expected to be adopted (so-called RES-2 Decree). Access to the FiT under the RES-1 Decree is subject to admission to competitive register or auction procedures. The results of the last auction under RES-1 Decree were published on 27 January 2022. However, Legislative Decree 199/2021 established that a new incentive regime shall be adopted, and that RES-1 Decree will continue to apply limited to the quotas of capacity not assigned until the new incentive scheme is enacted.
Green certificates (name of the scheme)	Under the RES-1 Decree, the green certificate mechanism has been entirely replaced by FiT.
Taxation	Taxation regime: transactions that include the generation and sale of electricity generated from renewable sources are in principle taxable under Italian taxation rules. The all-inclusive FiTs for RES and solar plants are linked to the injection of energy into the grid and both qualify as a remuneration paid to energy generators. For generators that qualify as business entities resident in Italy for tax purposes, such remuneration triggers: (i) corporate income tax ("IRES"), at a rate of 24%; and (ii) regional tax on productive activities ("IRAP"), at a standard rate of 3.9% (excluding reductions or increases on a local basis). FiT payments are also subject to VAT, the application of which under specified conditions may be subject to the reverse charge mechanism. The relevant energy supply purchaser must therefore register for VAT and make the relevant VAT payments.
Other	On 20 July 2004, the Ministry of Productive Activities in consultation with the Ministry of Environment and Land Protection adopted Decrees, as amended and supplemented, that set up Energy Efficiency Certificates. The Ministerial Decree 21 May 2021 outlined national targets for energy efficiency during the four-year period of 2021 to 2024. To achieve these energy efficiency targets, electricity and natural gas distributors can implement energy efficiency projects, obtaining Energy Efficiency Certificates, and purchase Energy Efficiency Certificates. Energy Efficiency Certificates are traded on the Energy Efficiency Certificates Market managed by the GME (*Gestore dei Mercati Energetici*). The all-inclusive tariff (*tariffa omnicomprensiva*) is for small RES plants that have a nominal capacity of up to 1MW and have been granted with incentives under RES-1 Decree. The tariff is fixed and includes both the incentive component and the value for net electricity generation. The Spot Exchange (*scambio sul posto*) provides for economic compensation between the value of the electricity fed into the grid and the value of electricity consumed on site. The Spot Exchange was abolished by Legislative Decree 199/2021. According to this decree, new incentive schemes must be adopted for local energy communities and collective self-consumption systems.

KAZAKHSTAN

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Target for 2030: 15% of total energy to be produced by RES facilities. Total projected power capacity of RES facilities is 7,150MW, of which: • Wind stations: 47.6% (3,405MW) • Small hydro power stations: 21.2% (1,516MW) • Solar stations: 30.9% (2,208MW) • Biofuel stations: 0.03% (21MW) Total projected annual energy generation by RES facilities is 30.4 million ("m") kWh including: • Wind stations: 59.5% (18.1m kWh) • Small hydro power stations: 30.2% (9.2m kWh) • Solar stations: 9.5% (2.9m kWh) • Biofuel stations: 0.06% (0.2m kWh) As of Q1 2022: 3.03% of total energy was produced by RES facilities. Total power capacity of RES facilities is 2,065.34MW, of which: • Wind stations: 33.1% (683.95MW) • Small hydro power stations: 13.6% (280.98MW) • Solar stations: 52.9% (1092.56MW) • Biofuel stations: 0.4% (7.82MW) Total energy generation by RES facilities is 933.07m kWh, including: • Wind stations: 58.4% (544.99kWh) • Small hydro power stations: 11.8% (109.66kWh) • Solar stations: 29.8% (278.02kWh) • Solar stations: 29.8% (0.4kWh)
Key generators of renewable energy	There is no publicly available data.

KAZAKHSTAN

OVERVIEW (CONTINUED)

Pre-qualifications	Financial capability must be proved by a bank guarantee or by a stand-by letter of payment. The amount is to be calculated as follows: (i) if the auction is conducted without documentation indicating technical details of the planned RES facility, KZT2,000 (about US$4) should be taken per 1kW of power capacity of the planned RES facility as stated by the applicant, (ii) if the auction is conducted with documentation indicating technical details of the planned RES facility, KZT5,000 (about US$10) should be taken per 1kW of power capacity of the planned RES facility as indicated in the schedule. Legal capacity is proved by presentation of corporate documents (such as charter, powers of attorney, registration documents). *Other requirements*: The participant must also provide documents confirming that it has title to the plot of land (or indicate if the plot of land is listed in the relevant schedule) and technical documents confirming the presence of a coordinated point of connection to the existing power lines.

FINANCIAL INCENTIVES

Feed-in tariffs	The RES Centre (ie the authorised centre for procurement of electricity produced by RES facilities) must procure electricity using: (i) fixed tariffs (approved by the Government) or (ii) the auction price (subject to indexation in accordance with the order as approved by the Government). Fixed tariffs (in all cases excluding VAT): KZT22.68 for wind power plants; KZT70 for solar power plants using photovoltaic ("PV") modules on the basis of Kazakhstan silicon (Kaz PV) of a total capacity of 37MW; KZT34.61 for other PV converters of solar energy; KZT16.71 for small hydro power plants ("HPPs"); and KZT32.23 for biogas facilities. Maximum starting auction prices (in all cases excluding VAT): KZT21.53 for wind power plants; KZT16.96 for PV converters of solar energy; KZT15.2 for HPPs; and KZT 32.15 for biogas facilities.
Green certificates (name of the scheme)	N/A
Taxation	There are no special tax incentives for RES facilities. However, RES facility construction projects may obtain tax incentives if implemented as investment projects.
Other	N/A

LATVIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Overall renewable energy source ("RES") share (2018; target 2020 = 40%) 40.3%: • Hydropower: 66% • Wind power: 3.3% • Solar power: 0.2% • Biomass: 12.6% • Biofuels: 9.3% • Heat pumps: 0.2% • Other renewables: 8.3% 2030 RES overall target is 45%.
	Key generators of renewable energy	Hydropower and biomass.
	Pre-qualifications	N/A
FINANCIAL INCENTIVES	Feed-in tariffs	Latvia's Feed-in tariff scheme is being phased out gradually; no new feed-in tariff permits have been issued since 2011.
	Green certificates (name of the scheme)	From 1 December 2020 and in accordance with the Electricity Market Law, the Latvian transmission system operator (TSO) - AS "Augstsprieguma tikls" (AST), is authorised to manage Guarantees of Origin ("GOs") in Latvia. AST issues European energy certificate system (EECS) compliant GOs in accordance with the agreement between AST and European energy certificate system transfer HUB supervisor for electricity generated from RES or high-efficiency cogeneration.
	Taxation	Subsidised Electricity Tax in the amount of 5 to 15% of the income generated from feed-in tariffs.
	Other	N/A

LITHUANIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	2020: 27.36% of gross final energy consumption, out of which: • Wind: 8% • Solar: 0.50% • Hydro: 2% • Biofuels: 5% • Biomass: 78% • Biogas: 2.50% • Other: 4% Lithuania is among the five most ambitious countries in the European Union ("EU") in terms of renewable energy targets. It is projected that by 2030, 45% of all the electricity consumed in Lithuania will be generated using renewable energy sources ("RES") (the target for 2020 was 30%).
Key generators of renewable energy	Projects in operation: • Enefit Wind (wind: 138.9MW) • Ignitis gamyba (hydro: 101MW) • Amberwind (wind: 73.5MW) • Renerga (wind: 57.5MW) Projects under development: • Ignitis Renewables (wind and solar: over 700MW) • East Wind Brokers (wind and solar: over 400MW) • European Energy Lithuania (wind: over 309MW) • LT energija (wind: 264MW) • E-Energy Invest (wind: 210.8MW) • Windfarm Akmenė One (wind: 75MW)
Pre-qualifications	Lithuania does not currently have pre-qualifications.

FINANCIAL INCENTIVES

Feed-in tariffs	• Most operating windfarms (about 85%) have a secured feed-in-tariff ("FiT") for 12 years, expiring in 2022-2028. • In 2010-2020, the development of renewables was mainly financed via FiT support schemes or support from EU funds. At the end of 2020, the FiT period of the earliest entrants into the FiT scheme expired. • Support for renewable energy power plants is allocated using technologically neutral auctions, ie electricity generators that use different RES technology for the generation of energy (wind, solar, biomass or any other) can take part in the auctions. However, there is a growing trend that renewable energy projects are being actively developed without any state support, therefore, auctions may not be used in the coming period. • Financial support for self-producing consumers will be allocated by 2030. • Financial support for 370MW of biomass and waste CHPs to be distributed by 2023.
Green certificates (name of the scheme)	A unit of electricity generated from RES and supplied to electricity grids and heat generated from RES and supplied to the heat supply system will be issued a guarantee of origin ("GO"). GOs are issued with a view to providing proof to final consumers of the share of energy, as supplied by the energy supplier, or the amount that is generated from energy from RES. The energy supplier will, in accordance with the procedure set out by the Law on Energy from Renewable Sources and within its remit, provide information to its final consumers on the share of energy, as supplied by the energy supplier, or the amount that is generated from RES. The share of energy supplied, or the amount will be calculated according to the amount of energy generated from RES that has been issued a GO.
Taxation	The Law on the Environmental Pollution Tax provides an exemption from the obligation to pay the pollution tax that is applied to the natural and legal persons that using biofuel who have proper documentation to substantiate the use. Under the Law on the Excise Duty, energy products produced using biomass are subject to partial or full exemption (as applicable) from the excise duty in accordance with the specific conditions established in the legal provision. The electricity generated using RES is exempted from the excise duty.
Other	The Law on Renewable Energy provides that the use of RES will be promoted by applying the specified support scheme consisting of one or several support measures. The following will be considered as support measures: • premiums to the market price • priority of transmission of energy from renewable sources • release of electricity generators from responsibility for the balancing of generated electricity and/or reservation of electricity generating capacities during the support period (exceptions are applicable) • support for production and processing of agricultural commodities, ie raw materials for the production of biofuels, biofuels for transport, bio lubricants and bio-oils • the requirements in relation to mandatory use of RES for energy generation and/or mandatory consumption of energy from renewable sources, also the requirements for the use of biofuels for transport • support of investments in renewable energy technologies • other preferences established by laws The Environmental Project Management Agency (EPMA) supports the installation of renewable energy generation facilities for natural persons and companies, supports investment projects in the form of interest subsidies and loans on soft terms.

LUXEMBOURG

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Energy source/production technology[1] Net electricity production (measured in GWh) Installed power (measured in MW) Natural gas: • 14.3% (173GWh) • 13.3% (79MW) Hydroelectric: • 8.5% (103GWh) • 5.9% (35MW) Wind power: • 26% (314GWh) • 23% (136MW) Biogas: • 5% (61GWh) • 2% (12MW) Photovoltaic (PV): • 14.8% (179GWh) • 46.8% (277MW) Biomass: • 23.6% (285GWh) • 5.9% (35MW) Waste to energy: • 7.7% (93GWh) • 2.9% (17MW) According to the integrated national energy and climate plan for 2021-2030, Luxembourg aims to increase the share of renewable energy from 11% in 2020 to 25% by 2030.
Key generators of renewable energy	• Enovos (directly and through subsidiaries) that provides solar, wind, biomass and hydroelectric energy. • Société électrique de l'Our (SEO), directly and through subsidiaries which owns hydroelectric powerplants and wind powerplants.

OVERVIEW (continued)	Pre-qualifications	• All natural or legal persons are eligible to produce electricity from renewable energy sources. • Only civil or cooperative companies can enter into a feed-in tariff contract for photovoltaic plants with a capacity of between 200 and 500kW. • For wind energy, market premiums are only available for capacities greater than or equal to 3MW or 3 production units. • Projects from 200 to 500kW and from 500kW to 5MW are subject to tender processes. • Other requirements include that only plants located in Luxembourg are eligible, only new generating stations may qualify, and that the bidding entity must also be the producing entity.
FINANCIAL INCENTIVES	Feed-in tariffs	The main support instruments for renewable energy are feed-in tariffs and subsidies granted for investment and installation costs for solar heating, heat pumps and household biomass boilers.
	Green certificates (name of the scheme)	N/A
	Taxation	Additional autonomous excise duty called 'CO₂ tax' on energy products from fossil energy sources.
	Other	N/A

Endnotes

1. Chiffres clés du marché de l'électricité, Année 2021 – Partie I (ILR).

MALTA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	As an EU Member State, Malta has been tasked with achieving at least 19% of its total electricity consumption from renewable energy sources ("RES") by 2030, in conformity with the National Renewable Energy Action Place. Malta is progressively advancing its share of energy from RES and has to date registered a total of 8.9% of its electricity generation as being produced through renewable means. According to collective data, the year 2019 featured the highest power generation due to high amounts of renewable energy technology installed in residential houses.
	Key generators of renewable energy	Solar energy will account for 60% of renewable power growth in 2022, ahead of wind and hydropower, according to the International Energy Agency, which advises developed nations on energy policy. This incentive is primarily due to new energy grant schemes for photovoltaic ("PV") panels, as well as for solar water heaters. Therefore, homeowners may benefit from a 50% subsidy on solar water heaters toward a maximum of €700, along with a 50% subsidy on PV panels, inverts and support frames, up to €2,300.
	Pre-qualifications	There are no pre-qualifications.

MALTA

FINANCIAL INCENTIVES

Feed-in tariffs	The Feed-in Tariffs ("FiTs") for electricity produced by solar PV systems were first introduced in 2010. A recent scheme catered for individuals benefitting from a residential grant of no more than 50%. A person who opted for a PV system investment with a grant, benefited from a 50% financial assistance and a €0.22/kWh FiT for six years. This means that they would typically receive more than the amount invested during the first six years and roughly twice the amount invested over the lifetime of the project. The amount would be even higher if part of the electricity generated is offset with the electricity consumed. By means of Legal Notice 16 of 2021, any PV systems that are installed on residential or domestic premises which have a FiT for six years or eight years, the applicable rate after the expiry of either six years or eight years will be €0.105/kWh. Such amount is payable for 14 years for those having a FiT of six years whereas those with a FiT of eight years are payable for 12 years. The new support scheme will cater for households investing in standard PV systems and integrated battery storage. The first scheme concerns PV systems with standard solar inverters, these benefit from a grant of €625/kWp and 50% of capital spend, capped €2,500. These will get a FiT of €0.105/kWh for 20 years. The second scheme supports a battery-ready PV system with a hybrid inverter or separate solar inverter and will benefit from a €750/kWp grant, a €3,000 maximum grant on capital spend (up to 50%), and a €0.105 FiT. The third scheme supports new combined PV and battery storage systems which self-consume more solar-generated electricity. The system can combine PV panels with either hybrid inverter and battery, or solar inverter and battery inverter and battery, or solar inverter and AC battery. The grant is of €750/kWp with a maximum €3,000 capital spend grant, a €0.105 FiT, and then €600/kWh or 80% of the cost of the storage system, capped at €3,600. A fourth scheme covers upgrades to add battery storage systems, at €600/kWh or 80% of the battery cost capped at €3,600, and €450/kWp for a new hybrid inverter, capped at €1,800. Households that have already invested in a PV system, having a hybrid inverter and a battery will get €600/kWh or 80% of cost for battery, capped at €3,600.
Green certificates (name of the scheme)	ECO Certificate which safeguards the environmental, socioeconomic and sustainability of both farmhouses and hotels. The Energy Performance Certification informs potential buyers about the energy performance of a building unit. It also provides guidance on cost effective improvements for the attainment of a better energy efficiency
Taxation	Under the Deduction (Electric Vehicles) (Amendment) Rules 2016, a company that continues a trade or business is entitled to a deduction equivalent to 150% of the cost that is incurred in that case of an electric vehicle and 125% of the cost incurred upon the acquisition of a hybrid vehicle. The maximum total deduction in the case of an electric vehicle is €40,000 and for a hybrid vehicle is €30,000. In 2018, the Energy and Water Agency launched a support scheme for micro, small and medium sized enterprises in order to cover energy audit costs. The cumulative savings for 2020 was 100GWh.
Other	

MOLDOVA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc.) and 2030 Target for renewable energy	Global percentage of energy generation from renewable sources[1] - more than 25.06% (2020). Existing capacities (As of January 2021): • Wind: 73.38MW • Solar: 14.48MW • Large hydro: 16MW • Small hydro: 0.25MW • Biogas: 6.35MW Global target for 2020: 17% No target has been set for the period after 2020.
Key generators of renewable energy	• PHR Wind S.R.L. (4.0MW) • Cerenergo Grup S.R.L. (4.0MW) • Domulg Energy S.R.L. (4.0MW) • Irarom-Grup SRL (3.9MW) • Sudzuker Moldova SA (3.6MW) • Importex-Trans SRL (3.3MW) • Printemps SRL (3MW) • WindMD-JT SRL (2.64MW) • Cariera Cobusca SA (2.6MW) • Nordix-prim SRL (1.95MW)
Pre-qualifications	Requirements for the applicant: • is not involved in an insolvency process, does not have its assets seized, is not involved in a liquidation or reorganisation process, its activities are not suspended • proves that it has experience in construction and/or the exploitation of power plants (for the respective type of technology) • does not have its licence (if held) suspended or withdrawn • does not simultaneously conduct the activity of the transmission system operator ("TSO") or distribution system operator ("DSO") • the equipment of the power plants using renewable energy sources ("RES") were not previously used (manufactured not earlier than 48 months before the putting into use of the respective power plant) • in the case of cogeneration power plants (using biomass as fuel), only production technologies with an overall efficiency of at least 80% are used • proves the fulfilment of the criteria regarding the viability of the project

MOLDOVA

FINANCIAL INCENTIVES

Feed-in tariffs	Support scheme for promotion of energy from RES: • fixed price, set within a tender, for eligible producers operating a power plant with a capacity exceeding the capacity limit established by the Government of Moldova ("GoM") • fixed tariff, set by the National Agency for Energy Regulation ("ANRE") for the eligible producers operating a power plant with a capacity not exceeding the capacity limit established by the GoM (but not less than 10kW)
Green certificates (name of the scheme)	Guarantees of origin ("GO") are instruments evidencing the origin of electricity generated from RES. The GOs are issued by the central supplier of electricity upon the request of the producer and can be transferred from one electricity producer to another, from an electricity producer to a supplier of electricity and from one supplier of electricity (holding the GO) to another. Upon the request of a participant to the electricity market, ANRE recognises the GOs issued by the authorities of the member states of the European Union (EU) or of the states which are parties of the Energy Community.
Taxation	N/A
Other	Priority dispatch: The TSOs and DSOs are under the obligation to grant priority to electricity produced from RES at the dispatching of electricity production capacities, to the extent that the security of the electricity system is not affected.

Endnotes

1. Energy Efficiency Agency Information (available at www.aee.md/ro/page/surse-de-energie-regenerabila).

MONTENEGRO

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2020, Montenegro registered a 43.77% share of renewable energy, exceeding its overall 2020 target. The significant increase in the share compared to the previous year can be attributed to a decrease in consumption. Sectorial targets for electricity and heating and cooling were also overreached. In 2021, Montenegro registered a 63.55% generation share of RES and high-efficiency cogeneration, and was distributed as follows: • Hydro: 48.76% • Wind: 4.80% • Brown coal and lignite: 43.03% • Other: 3.4% Montenegro's target for 2030 regarding the share of energy from renewable sources in gross final consumption of energy is 50%.
	Key generators of renewable energy	The key generator of renewable energy in Montengro is Elektroprivreda Crne Gore ("EPCG"). The Montenegro RES sector is dominated by projects using hydro power; wind projects are gradually breaking through.
	Pre-qualifications	N/A
FINANCIAL INCENTIVES	Feed-in tariffs/Feed-in premiums	Montenegro is currently in the process of adopting its first Renewable energy sources Act ("Res ACT"). The RES Act will likely account for the specific circumstances in Montenegro (in particular, the lack of an operational day-ahead market) that are likely to require 'transitional arrangements' to accompany the introduction of a feed-in-premiums ("FiP") in the short term. The transitional regime could take one of the following two forms, which are yet to be determined in the RES Act: (i) Feed-in tariffs ("FiT") with a conversion clause to FiP: In this case, generators would initially conclude a 'traditional' FiP with an offtaker of the energy produced (ideally the entity that also acts as offtaker for the FiP for small plants). The FiP would then automatically convert to a two-way contract for difference (CfD) once certain 'market readiness criteria' have been fulfilled. Bankability aspects of such arrangements will be taken into consideration; and (ii) the FiP with a reference price whose definition ('underlying market') changes over time. In this case, a foreign price index sourced from a well-established, liquid exchange such as the Southeast European Power Exchange (SEEPEX *a.d. Beograd*) ("SEEPEX") would initially serve as the reference price for the Montenegrin FiP agreement. The selection of price index needs to be such as to enable Montenegrin generators to access the price with no major hurdles and to forecast market access costs with a reasonable degree of certainty.
	Green certificates (name of the scheme)	Guarantees of Origin ("GO") are issued by the Crnogorski operater tržišta električne energije ("COTE") on request of the RES electricity generator.
	Taxation	Although the Montenegrin Energy Act envisages several incentive measures, there are currently no tax incentives for generation of electricity from RES.
	Other	N/A

Endnotes

1. Official Gazette of Montenegro, nos. 005/16, 051/17 and 082/20.
2. REGAGEN was the first Energy Community regulator to join the Agency for the Cooperation of Energy Regulators (ACER) working groups in January 2018.
3. Digitalisation of registers and records is expected under the Energy Act, and some registers have already been made available in electronic form, such as the licence and energy permits' registers.
4. Official Gazette of Montenegro, no. 1/22.
5. See www.eur-lex.europa.eu/LexUriServ/LexUriServ.do?uri=OJ:L:2011:326:0001:0016:en:PDF.
6. Official Gazette of Montenegro, nos. 31/2021 and 48/2021.
7. See www.montenegro.eregulations.org/media/pravila_za_funkcionisanje_distributivnog_sistema_elektricne_energije.pdf.
8. Official Gazette of Montenegro, nos. 80/2017 and 90/2017.
9. Official Gazette of Montenegro, no. 110/20.
10. Official Gazette of Montenegro, nos. 059/16 and 089/20.
11. Official Gazette of Montenegro, no. 110/20.
12. Official Gazette of Montenegro, nos. 57/2014, 3/2015 and 25/2019.
13. Directive 2019/944/EU.
14. 11 Directive 2019/1381/EU.
15. Directive 2009/73/EC.
16. Regulation 2009/942/EU.
17. Official Gazette of Montenegro, no. 66/2010.
18. The Ministry of Capital Investments is actively working on transposing the newly adopted electricity package of Energy Community by way of drafting and adopting a new Energy Act, which will be synchronised with the currently drafted RES Act.
19. Official Gazette of Montenegro, no. 47/2013.
20. Official Gazette of Montenegro, nos. 065/08, 074/10 and 040/11.
21. Official Gazette of Montenegro, no. 042/16.
22. Official Gazette of Montenegro, nos. 041/10, 040/11, 062/13.
23. Official Gazette of Montenegro, nos. 064/17, 044/18, 063/18, 011/19, 082/20, 086/22 and 004/23.
24. Directive 1994/22/EU.
25. Directive 2013/30/EU.
26. Official Gazette of Montenegro, nos. 56/2009, 58/2009, 50/2011 and 55/16.
27. Official Gazette of Montenegro, nos. 41/2010 and 62/2013.
28. Official Gazette of Montenegro, no. 51/18.
29. Official Gazette of Montenegro, no. 51/18.
30. Official Gazette of Montenegro, no. 73/2019.
31. Directive 2001/80/EC.
32. Official Gazette of Montenegro, no. 10/2011.
33. Directive took effect in the Energy Community on 1 January 2018. The directive requires operators of large combustion plants to significantly reduce the emissions of listed air pollutants. Opt-out is a time-barred implementation alternative to comply with the provisions of the directive.
34. Official Gazette of Montenegro, nos. 25/2010, 40/2011 and 43/2015.
35. Official Gazette of Montenegro, no. 54/16.
36. Official Gazette of Montenegro, no. 52/2016.
37. Official Gazette of Montenegro, nos. 27/2014 and 55/2016.
38. Official Gazette of Montenegro, nos. 28/2011 and 1/2014.
39. See www.balkangreenenergynews.com/which-western-balkan-countries-intend-to-introduce-carbon-tax.
40. See www.balkangreenenergynews.com/montenegro-adopts-by-law-to-introduce-emission-credits-system.

NETHERLANDS

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Energy generation from renewable sources: 11.1% in 2020, of which: • Biomass: 54% • Wind power: 23% • Solar power: 14% • Hydropower and others: 9% Renewable Energy Directive target for renewable energy in 2030: 27%
	Key generators of renewable energy	In the Netherlands, in the year 2021, the following companies generated the volumes of renewable energy set out below: • Eneco: 6,317GWh • Ørsted: 1,904GWh • RWE: 1,468GWh • Vattenfall: 1,300GWh
	Pre-qualifications	There are no specific pre-qualifications, other than the requirement to have the necessary permits (eg environmental, planning, nature and water permits) to build and operate the relevant renewable energy generation facility.
FINANCIAL INCENTIVES	Feed-in tariffs	Renewable Energy Production Incentive Scheme (Besluit Stimulering duurzame energieproductie, SDE++)
	Green certificates (name of the scheme)	Regulations governing Guarantees of Origin of Energy Produced from Renewable Sources and High-Efficiency Combined Heat and Power (*Regeling garanties van oorsprong voor energie uit hernieuwbare energiebronnen en HR-WKK-elektriciteit*)
	Taxation	• Small-scale investment allowance (*Kleinschaligheidsaftrek*) • Energy-saving investment credit (*Energie-investeringsaftrek*) • Environmental investment credit (*Milieu-investeringsaftrek*) • VAMIL tax scheme (random depreciation of environmental investments) (*Willekeurige afschrijving milieu-investeringen*) • Sporting facilities construction and maintenance incentive subsidy scheme (*Subsidieregeling stimulering bouw en onderhoud sportaccommodaties*)
	Other	N/A

NORTH MACEDONIA

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2021, the percentage of participation of RES in the total generation of electricity from local generators was 31.45% with the following breakdown: • Hydro: 68.12% • Small hydropower plants: 19.34% • Wind: 6.20% • Solar: 3.10% • Biogas: 3.25% • Biomass: 0.00% The target for 2020 for renewable energy is set by Renewable Energy Action Plan until 2025, with Vision until 2035, and the Energy Development Strategy until 2040. The commitments to the Energy Community oblige North Macedonia to increase the share of renewable energy in its mix. The threshold was lowered from 28% to 23% as the Government amended the National Renewable Energy Action Plan submitted to the Energy Community in 2012, to consider the lower biomass baseline data (17.2% compared to the 21% originally). The Energy Community's Ministerial Council approved this revision in November 2018. With the Energy Development Strategy until 2040, North Macedonia has outlined three scenarios for increasing the share of RES in the gross consumption of final energy as part of the decarbonisation goal. The share of RES in the gross consumption of final energy should aim the following projections until 2030: • reference scenario: 33% • moderate transition: 38% • green scenario: 40% The decarbonisation goal is also outlined in the draft National Energy and Climate Plan. According to this draft plan for achieving the decarbonisation goal, among other things, RES should participate with 38% in the final consumption of energy until 2030. The draft plan sets the 2030 target for the share of RES in the final energy consumption in the electricity sector at 66%. North Macedonia's target for RES participation in the electricity sector in line with this draft plan, includes a share of 66% of electricity generation from hydro power plants ("HPPs"), 20% from photovoltaic (PV) power plants, 10% from wind power plants, 3% from biogas thermal power plants ("TPPs"), and 1% from biomass TPPs in the final energy consumption in the electricity sector.
Key generators of renewable energy	• JSC Power Plants of North Macedonia ("ESM") • EVN Macedonia Elektrani SPLLC Skopje Macedonia
Pre-qualifications	After an open call in 2020 for the HPP Cebren project, ten companies submitted bids in the pre-qualification phase for the construction of HPP Cebren. The Government of North Macedonia subsequently announced that nine of these (five consortia and four individual bidders) have been selected for the second phase to continue the tendering procedure. It is expected that, in the upcoming period, the evaluation and choice of the most favorable bidder will be completed. If the evaluation of the offer is positive, it is expected that an agreement will be signed in 2023.

FINANCIAL INCENTIVES

Feed-in tariffs	The amount of the feed-in tariff ("FiT") and the period for which FiP can be awarded to the privileged renewable energy sector depends primarily on the type of RES used for electricity generation and the installed capacity of the facility (ie, delivered electricity) as follows: • hydro (installed capacity up to 10MW): ranging in blocks between €12.00 to €4.50/kWh for a period of 20 years • wind (Installed capacity up to 50MW): €8.9/kWh for a period of 20 years • biomass (Installed capacity up to 1MW): €18/kWh for a period of 15 years • biogas (Installed capacity up to 1MW): €18/kWh for a period of 15 years The electricity market operator must buy the entire generated electricity by privileged producers that use FiTs. FiTs cannot be awarded if the envisaged total installed capacity for that type of RES technology has already been reached.
Green certificates (name of the scheme)	The Rulebook on RES provides the framework for the guarantees of origin ("GOs") regarding the energy generated from RES. The GOs are issued monthly by the Energy Agency of the Republic of North Macedonia (who is also responsible for maintaining the relevant registry), for electricity generated in North Macedonia by generators of electricity from RES. Such GOs can be obtained by generators of electricity from RES that do not have a status of privileged producer under the Energy Law. The GO is with a standard size of 1MWh for every generated unit. GOs can be transferred during their validity to a holder of a licence for the generation, trade, or supply of electricity.
Taxation	There are no tax incentives for RES, except for the tax incentive and the preferential treatment regarding the trade and import of thermal solar system (5% rather than the general 18%).
Other	In 2019, the Government of North Macedonia adopted the Decree on Support Measures for Electricity Production from RES which, among other things, regulates feed-in premiums. Feed-in premiums are granted via a tender procedure conducted through an electronic auction. Feed-in premiums can be used by: • wind power plants (installed capacity up to 50MW, for a period of up to 20 years) • solar power plants (installed capacity up to 30MW, for a period of up to 15 years) The feed-in premium is awarded to privileged generators as an additional fixed amount of the price achieved by selling each generated kWh on the wholesale electricity market. The bidders must submit all necessary documentation to prove that they fulfil the prescribed conditions.

NORWAY

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2020, the generation amounted to an all-time high of 154.2TWh, of which about: • Hydro: 91.8% • Wind: 6.4% • Geothermal: 1.7% The total Norwegian energy production is about 2700TWh a year, of which about 2500TWh stems from oil and gas. The 2020 target for renewable energy consumption is 67.5%. This target was reached in 2014. Norway has not set a renewable energy target for 2030.
	Key generators of renewable energy	• Statkraft Energi AS • Hafslund Eco AS / Hafslund Eco Vannkraft AS • Hydro Energi AS (Norsk Hydro ASA) • Agder Energi AS • BKK Produksjon AS • Lyse Kraft DA • NTE Energi AS
	Pre-qualifications	N/A
FINANCIAL INCENTIVES	Feed-in tariffs	N/A
	Green certificates (name of the scheme)	A joint Norwegian-Swedish electricity certificate market for investments in electricity production from RES was introduced in 2012. The certificate scheme provides incentives for eligible investments in electricity production from RES (as defined in the Renewable Energy Directive) in both Sweden and Norway. The scheme will be in effect until the end of 2035.
	Taxation	N/A – the tax system is not being used to incentivise renewable energy production in Norway
	Other	The state-owned enterprise, Enova, has a mandate to make energy consumption and generation more sustainable, while simultaneously improving security of supply. It is financed through funds allocated from the Energy Fund. The Energy Fund is financed through a small additional charge to electricity bills and supports the introduction of new technology, energy efficiency measures and so on.

POLAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Share of energy from renewable sources in gross final consumption of energy for year 2021 amounted to 15,62% (share of energy from renewable sources in total primary energy amounted to 21.12%). The share of particular energy sources was: • Biofuels: 69.35% • Wind energy: 10.90% • Liquid biofuels: 8.10% • Biogas: 2.49% • Heat pumps: 2.89% • Solar energy: 3.31% • Hydro energy: 1.57% • Renewable municipal waste: 1.16% • Geothermal power: 0.22% Poland's target for 2030: 23% share of energy from renewable sources in gross final consumption of energy.
	Key generators of renewable energy	Key generators of renewable energy in Poland include: • EDP Renewables • Energix Renewable Energies • RWE • E.ON • Mashav Energia • Vortex • GDF Suez • Mitsui & J.Power • Acciona • EnergiaLine • BayWa r.e. (wind energy) • Dalkia (biomass) • Poldanor – AXZON Group (biogas) The biggest Polish energy groups also play a key role on the RES market: ENEA, ENERGA, TAURON, PGE.
	Pre-qualifications	Only ready-to-build installations are entitled for support.
FINANCIAL INCENTIVES	Feed-in tariffs	Feed-in tariffs and feed-in premiums exist for small renewable installations (as a rule up to 1MW; the threshold for some types of installations at the level of 2.5MW will be applicable upon acceptance by the European Commission).
	Green certificates (name of the scheme)	A support scheme based on green certificates (*świadectwa pochodzenia*) applies to installations that commenced generation before mid-2016. From 1 July 2016, an auction system replaced the green certificates support.
	Taxation	N/A
	Other	Renewable energy generators can take part in the auction system where various renewable sources compete for financial support, the lower the price for the energy produced by a particular renewable source the greater the chances of winning the auction. The auction system is similar to contract-for-difference (CfD) mechanisms for installations over 0.5MW where generators sell energy on the market and apply for the difference between the auction price and market price. Smaller installations are entitled to sell energy at the auction price to obliged seller (ie appointed energy trading companies).

PORTUGAL

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind- , solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In the first half of 2022, 57% of energy generated in Portugal was from renewable sources. Thus, the target of 60% of energy generation from renewable sources was not met, as set forth by the Portuguese Renewables' Action Plan for 2013-2020 and by the National Energy Strategy for 2016 (both adopted by Order in Council no. 20/2013, of 10 April) in accordance with the Renewable Energy Directive. Renewable source breakdown (% of the total energy generation): • Wind power: 30% • Hydro power: 13% • Biofuels: 8.1% • Solar power: 5.9% The Decree-Law no. 84/2022, of 9 December aims to incorporate 49% of renewable energy sources (RES) in Portugal's final gross consumption of energy by 2030.
Key generators of renewable energy	• Acciona energia portugal (Grupo) • EDF EN • EDP Renoáveis • Finerge • Generg • Iberwind • Neoen • New Finerge • Trustwind
Pre-qualifications	The beginning of the procedure to obtain an electricity production license depends on the previous allocation of reserve injection capacity to the grid. According to Article 18 of Decree-Law no. 15/2022, of 14 January, the allocation of reserve injection capacity to the grid consists of a title issued in one of three modalities: • general access, through a request made by the applicant through an electronic platform • an agreement between the interested party and the grid operator • a competitive bidding procedure When there is a competitive bidding procedure, there must be a pre-qualification of the different candidates. This must be based on transparent, clear, and non-discriminatory requisites.

Pre-qualifications (continued)	There are minimum requisites based on the technical capacity of the company that are essential in these competitive bidding procedures, as per Article 165 of the Portuguese Public Procurement Code: • the curricular experience of the candidates • the human, technological, equipment or other resources used, in any capacity, by the candidates • the candidates' organisational model and capacities, namely in terms of management and integration of specialised areas, support information systems and quality control systems • the capacity of the candidates to adopt environmental management measures in the execution of the contract to be signed There are also minimum financial requisites for candidates in a competitive binding procedure. Apart from this, according to Article 27 of Decree-Law no. 15/2022, of 14 January, there is general criteria on the attribution of a production licence, based on certain pre-qualifications: • contributing to the promotion of security of supply, considering the respective monitoring report • contributing to the achievement of the energy and environmental policy objectives and the strategic instruments in force, namely those resulting from the PNEC 2030, approved by the Resolution of the Council of Ministers no. 53/2020, of 10 July, and in the Roadmap for Carbon Neutrality 2050, approved by the Resolution of the Council of Ministers no. 107/2019, of 1 July • the share of electricity generation capacity held by the interested party within the scope of the Iberian Electricity Market (MIBEL), on 31 December of the year prior to the year of presentation of the request, may not exceed 40% • the reliability and security of the electricity grid, installations and associated equipment under the terms set forth in the Network Regulation • the specific characteristics of the applicant, namely its technical and financial capacity

Feed-in tariffs	Feed-in-tariff ("FiTs") are facing reduction or abolition. Therefore, the renewable energy sector in Portugal is gradually becoming subsidy-free. Below are the relevant regimes regarding the FiTs in Portugal: • Portuguese renewable plants that were granted licensing rights between June 1999 and 31 December 2001 (and also to the plants already licensed in June 1999 that have decided to change to the 1999 Regime), are subject to the 1999 regime. Decree-Law no. 168/99 introduced a first version of the aforementioned renewables remuneration formula, a guaranteed remuneration system for 12 years, as well as the legal obligation of the relevant operators of the public grid to acquire all electricity generated by renewables. • Portuguese renewable plants that were granted licensing rights between 1 January 2002 and 17 February 2005 are subject to the 2001 Regime. Decree-Law no. 339-C/2001 introduced the 'Z coefficient' in the formula, according to which the environmental portion is multiplied by the Z coefficient, which varies according to the respective technology. Due to the introduction of this Z coefficient, the payment system for renewables, which was only based on avoided costs, progressed considering the costs according to different technologies, thereby establishing different payments pursuant to technology. The 12 years limit for the guaranteed tariff was eliminated but reinstated to this regime by the 2005 Regime.

PORTUGAL

Feed-in tariffs (continued)	• Portuguese renewable plants whose licensing rights were recognised between 17 February 2005 and 1 June 2007 are subject to the 2005 regime:[1] Decree-Law no. 33-A/2005 introduced in Portugal the guaranteed remuneration up to 15 years and up to specific power limits (to the first 33GWh injected to the grid per MW of power injection capacity (ascertained according to a power factor of 0.98) for wind and 21GWh for solar PV) and also depending on the renewable technology used. • Portuguese renewable plants whose licensing rights were recognised between 1 June 2007 and 7 November 2012 are subject to the 2007 regime:[2] Decree-Law no. 225/2007 reviewed the formula and introduced the possibility of increasing the capacity of the plants (*sobreequipamento*) and the relevant remuneration conditions thereto. • Finally, Portuguese renewable plants whose licensing rights were recognised under Decree-Law no. 215-B/2012, of 8 October, shall be subject to the remuneration regime. The current legal regime applicable to projects in renewable energy is set out in Decree-Law no. 15/2022, of 14 January, which states that the general remuneration is based on market prices (through organised markets or bilateral contracts), while maintaining the guaranteed remuneration scheme (*regime de remuneração garantida*) in the context of public tender procedures. Power plants that benefit from guaranteed remuneration or other remuneration regime under previous laws are allowed to maintain such remuneration schemes. In 2013, there was a change in legislation in Portugal allowing the generators of renewable energy to choose between several alternatives for the remuneration framework for years following the period of guaranteed remuneration. After the aforementioned guaranteed period or if the power limit is reached, both in respect of wind (15 + 5 years) and solar PV (15 years), the electricity generated will be remunerated according to the market prices, without prejudice to any potential sale of green certificates regime. Should any plant under any of the above regimes change to market prices, it would be prevented from reverting back to the guaranteed remuneration scheme.
Green certificates (name of the scheme)	According to Decree-Law no. 15/2022, the green certificates (*Garantias de Origem*) are electronic documents that prove to the end consumer that a given amount of energy was produced from a renewable energy source. Law no. 71/2018, of 31 December, approved the State Budget Law for 2019 and entrusted the powers of the Issuing Authority for Guarantees of Origin ("EEGO") to the Transmission System Operator (TSO) (*REN – Redes Eléctricas Nacionais, S.A.*) (previously assigned to DGEG in 2015). Following the aforementioned law, Order no. 53/2020, of 28 February set forth the fees due to the EEGO for the services provided within the scope of its competence, namely the registry before the EEGO platform, the issuance, transfer and cancelling of the green certificates. Presently, approximately 350 entities are registered before the EEGO for the issuance of green certificates.
Taxation	Urban property exclusively intended for the generation of energy from renewable sources benefit from a 50% reduction of the property municipal tax rate if generation started before 31 December 2019. This benefit is granted for a five-year period. Municipalities are now entitled with the power to create their own five to ten-year exemptions. The Portuguese State Budget Law for 2014 created an Energy Sector Extraordinary Contribution ("ESEC"), safeguarding only the generators of renewables (except certain hydroelectric and cogeneration plants). Although it was designed to be in force for a limited period, the ESEC has been renewed every year since 2014 and is expected to be in force until at least the fiscal year of 2023, according to the State Budget Law Draft for 2023. Since 2019, ESEC has been levied on the generators of renewables under the guaranteed remuneration regime, only the following are exempt: (i) generators holding licences or rights granted in the context of a public tender; (ii) generators operating small-scale production units or self-consumption production units; and (iii) generators of electricity and heat through micro-cogeneration plants.

Other	The generators of renewable energy, whenever benefitting from a guaranteed tariff, are entitled to sell all or part of the electricity generated to EDP SU, the supplier of last resort (*comercializador de último recurso*). There are also incentives to promote investment in research and development activities, which may attract long-term investments based on new technology and creation and retention of knowledge. Order in Council no. 202/2015, of 13 July 2015, adopted a new and specific remuneration regime applicable to the generation of renewable energy from ocean sources or locations (regardless of the form of generation) using technologies in experimental or pre-commercial stage. It is a €80/MWh FiT that is applicable up to a 50MW share of power injection capacity reservation in the Public Grid, and applicable for a period of 20 years from the commencement of the electricity supply to the grid. A number of cases that may justify the increase of the applicable remuneration are provided for.

Endnotes

1. The 2005 Regime could also be applicable to Portuguese renewable plants already licensed in 17 February 2005 that have requested the change to the 2005 Regime to the public authorities.
2. The 2007 Regime could also be applicable to Portuguese renewable plants already licensed in 1 June 2007 that have requested the change to the 2007 Regime to the public authorities.

ROMANIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc)[1] and 2030 Target for renewable energy	Overall renewable energy generation: 45.28%, broken down per technology as follows: • Hydro (including large hydro): 29.08% • Wind: 12.66% • Biomass: 0.84% • Solar: 2.69% • Other renewable sources: 0.01% 2030 Target for renewable energy under the 2021-2030 Integrated National Energy and Climate Plan: 30.7% share of renewable energy
	Key generators of renewable energy	• Hidroelectrica SA • EDP Renewables (EDPR) • ENEL Green Power Romania • Engie Romania • Macquarie Infrastructure and Real Assets • Samsung
	Pre-qualifications	Since 2005, Romania has used a combined system of mandatory quotas and green certificates to incentivise renewable energy deployment. This system applied to renewable energy projects commissioned into operation by the end of 2016. Currently, there is no support scheme for new-built renewable energy projects, but Romania is working towards implementing a new scheme in the form of a Contract for Difference ("CfD"), which is expected to be largely similar to the British CfD system.
FINANCIAL INCENTIVES	Feed-in tariffs	Applies only to small scale prosumer projects.
	Green certificates (name of the scheme)	Has applied to projects commissioned into operation until the end of 2016.
	Taxation	No tax incentives.
	Other	A CfD scheme is expected to go live in 2023.

Endnotes

1. As of 2020, according to the annual 2020 energy market report issued by the Romanian Energy Regulatory Authority.

SERBIA

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	The share of RES in Serbia is 21.44%. Serbia's goal is 32% of renewable energy in its total annual energy consumption by the 2030.
Key generators of renewable energy	In Serbia, hydroelectric power plants produce about 80% of the nation's electricity from renewable sources. Up to 2.355 MW is the capacity of Serbian large hydropower facilities that are a part of the (EPS) network and do not receive government subsidies.
Pre-qualifications	According to the RES Act, power plants that use RES are: • Hydro power plant • Biomass power plant • Biogas power plant • Wind power plant • Solar power plant • Geothermal power plant • Biodegradable waste power plant • Landfill gas power plant • Gas-fired power plant from a municipal waste treatment plant water • Power plant that uses other renewable energy sources

FINANCIAL INCENTIVES

Feed-in tariffs	Summary: Feed-in-tariffs are determined by the Government of Serbia. Mechanism: Projects under 500 kW and 3 MW for wind, have the right to secure the feed-in tariffs through competitive auctions. The Ministry conducts auctions based on the available quotas which are prescribed by the Government. Qualification is the eliminations phase of the auction procedure in which a selection is carried out of registered participants based on the fulfilment of the conditions prescribed by the secondary legislation.
Green certificates (name of the scheme)	The Guarantees of Origin are instruments issued by the TSO and are issued upon a request from the RES electricity producer.
Taxation	There are currently no tax incentives for generation of electricity from RES.
Other	Market premiums: Market premiums are a newly adopted support instrument. Market premiums are a type of operational state aid that represents addition to the market price of electricity that users of the market premium delivered to the market, and which is determined in Eurocents per kWh in the process auction. Market premium users sell electricity on the electricity market. A market premium can be acquired for all, or part of the capacity power plants. The market premium is paid on a monthly basis for electricity that was delivered by the power plant to the power system. Market premiums are designed in the form of a doble sided contract for differences. Balancing Support: Further support for RES projects is granted in the form of partial balancing support for RES producers. RES producers are relieved of responsibility for their imbalances up to a certain imbalance per-centage. For the imbalances above such percentage will RES producers pay a fixed fee for each MWh produced. The percentage and the method of calculation of the fixed fee remain to be specified in the secondary legislation. Such balancing support would be available until establishment of a liquid organized intraday electricity market in Serbia.

SLOVAKIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	The target for 2020 was 14% of total energy consumption. This target was accomplished with 17% achieved (mainly water and solar). The target for 2030 is 19.2%. In addition, it is estimated that green energy in industry will increase by 1.1% annually. In Slovakia, the potential of geothermal energy is confirmed by projects as well as hydrogeological measurements and surveys.
	Key generators of renewable energy	Slovenské elektrárne, a.s.
	Pre-qualifications	Depending on the auction.
FINANCIAL INCENTIVES	Feed-in tariffs	The feed-in tariff scheme applies to electricity generation from renewable energy sources ("RES") and high-efficiency cogeneration depending on the source and installed capacity. The scheme is based on an additional payment included in the feed-in tariff set for a certain type of renewable energy (eg solar energy).
	Green certificates (name of the scheme)	A green certificate (under Slovak law, a guarantee of origin of electricity from RES) is issued in electronic form for electricity generated from RES or by cogeneration upon request of the electricity producer. This certificate is issued for 12 months and is tradeable in other EU Member States. There are no mandatory quotas for use of a guarantee of origin of electricity from RES.
	Taxation	Electricity generated from RES is generally exempted from the consumption tax levied on electricity.
	Other	N/A

SLOVENIA

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In terms of gross consumption of energy from renewable energy sources ("RES") relative to gross energy consumption: **2021**: 23.5% share (against a target of 25%) **2030 target**: 27% share under the Integrated National Energy and Climate Plan for the Republic of Slovenia (*Celoviti nacionalni energetski in podnebni načrt Republike Slovenije*)
	Key generators of renewable energy	• HOLDING SLOVENSKE ELEKTRARNE d.o.o. • GEN energija d.o.o. • Elektro Ljubljana OVE d.o.o.
	Pre-qualifications	Only new, predominantly new and refurbished RES generating plants with a capacity up to 10MW, with the exception of wind plants with a capacity of maximum 50MW (20MW for combined heat and power plants ("CHP")), are eligible for support. Further pre-qualification criteria are not expressly established in legislation, but are determined by the Energy Agency for each public tender (eg final construction permit where applicable, justification of the project based on the applicable guidelines).
FINANCIAL INCENTIVES	Feed-in tariffs	Feed-in tariffs are managed by the Centre for RES/CHP (*Center za podpore*) within BORZEN, d.o.o. (electricity market operator). The centre promotes supporting schemes for electricity production from RES and high efficiency cogeneration. The financial incentives may be granted in two basic forms: (i) a guaranteed purchase (for production units with a nominal power capacity below 500kW); and (ii) an operating premium. Under the guaranteed purchase incentive, the Centre for RES/CHP at BORZEN, d.o.o. takes over the electricity from the power plant at a guaranteed price and sells it to the market. Under the operating premium incentive, the producer is entitled to a premium equalling the difference between the full (guaranteed purchase) price and the market price, which is determined *ex ante* on a yearly level, based also on plant type.
	Green certificates (name of the scheme)	If a certain amount of electricity is generated from RES, the Energy Agency (*Agencija za energijo*) issues guarantees of origin of electricity (one for every 1MWh of energy).
	Taxation	The Motor Vehicle Tax Act (*Zakon o davku na motorna vozila*) exempts electric vehicles ("EVs") from the annual fee and (since the beginning of 2021) from the payment of tax on motor vehicles. For other motor vehicles, tax is calculated based on their carbon dioxide ("CO_2") emissions and the type of fuel they use. The Motor Vehicles Charges Act (*Zakon o dajatvah za motorna vozila*) also provides an incentive to purchase motor vehicles that emit less CO_2 by taking the emissions into account when determining the annual fee.
	Other	The Decree on the self-supply of electricity from the RES (*Uredba o samooskrbi z električno energijo iz obnovljivih virov energije*) enables all self-supplying end-consumers to be (partially) exempted from certain contributions, provides subsidies for the production of electricity from RES and the option to obtain certificates of origin. It also sets out a new calculation of network charges, abolishing the previous net metering regime which was not compliant with Directive 2019/944/EU. The Eco Fund (*Eko sklad*) offers loans or guarantees for specific environmental-friendly investments, eg subsidies for the purchase of EVs and construction of nearly zero-energy buildings. Investment subsidies are available to investors in renewable projects (funded through EU cohesion funds).

SPAIN

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2030, the total energy generation from renewable energy sources ("RES") is expected to represent 74% of the total energy mix generation in Spain (337,448GWh), according to PNIEC and the Spanish Ministry for Ecological Transition and the Demographic Challenge ("MITERD").
	
	In 2021, the total energy generation from RES represented 48.4% of the total energy mix generation in Spain (246,805GWh), according to REE (*Red Eléctrica de España*).
	
	The following breakdown for the different RES is according to sources from the Institute for the Diversification and Saving of Energy (IDAE), which reflects the actual capacity for 2020/2021 (depending on the most recent figures available) and the estimated capacity for 2030:
	• Hydroelectric:
	  ◦ 2021: 17,094MW
	  ◦ 2030: 14,109MW
	• Wind energy (including onshore and offshore):
	  ◦ 2021: 28,336MW
	  ◦ 2030: 38,033MW
	• Solar thermoelectric:
	  ◦ 2021: 2,304MW
	  ◦ 2030: 2,303MW
	• Solar photovoltaic:
	  ◦ 2021: 15,174MW
	  ◦ 2030: 18,921MW
	• Biomass:
	  ◦ 2020: 877MW
	  ◦ 2030: 613MW
	• Geothermal:[1]
	  ◦ 2020: 0MW
	  ◦ 2030: 30MW

Key generators of renewable energy	• Acciona Energía SA • Enel Greenpower España S.L. • Iberdrola SA
Pre-qualifications	N/A

Feed-in tariffs	Royal Decree ("RD") 413/2014, of 6 June 2014, which regulates the generation of electricity from RES, cogeneration, and waste ("RD 413/2014"), implemented a new system of specific remuneration (*retribución específica*). This remuneration is received in addition to the remuneration on the sale of energy valued at market rates and for certain plants that generate electricity using renewable energy, cogeneration, or waste-to-energy technologies (including biomass plants) in order to be able to cover the costs necessary to compete on an equal footing with other technologies while obtaining a reasonable rate of return in reference to the standard plant applicable in each case. The specific remuneration has two different components: • an installed power component that covers the investment costs of a standard installation that cannot be recovered through energy sales, if any • an operation component covering the shortfall between operating costs and income obtained by the standard installation from the market, if any To calculate the specific remuneration, each plant is allocated a standard reference plant on the basis of its characteristics by ministerial order. As established by RD 413/2014, a set of remuneration parameters apply to each standard plant. These parameters make up the specific remuneration applicable to the plants falling under the umbrella of each standard plant. In addition, in exceptional circumstances it is possible for the remunerative regime to include a subsidy for investment in non-peninsular power systems when the overall cost of electricity generation is reduced, as well as a subsidy for participation in what are known as system adjustment services. Plants that participate in system adjustment services will receive the remuneration established by applicable regulations..
Green certificates (name of the scheme)	Since 2007, there has been a system of Guarantees of Origin ("GO") for electricity generated by renewable facilities. This is regulated by Order ITC/1522/2007, of 24 May, as well as in Circular 1/2018, of 18 April, of the National Markets and Competition Commission (*Comisión Nacional de los Mercados y la Competencia*). In accordance with the provisions of these regulations, a GO is an accreditation, in electronic format, which ensures that a given number of MWh of electrical energy generated in a plant, in a given period of time, has been generated from RES or high-efficiency cogeneration. Generators or, where appropriate, their representatives, may request a GO to be issued for energy generated in electricity generation facilities from renewable primary energy sources or using high-efficiency cogeneration, as well as for energy generated from the biodegradable fraction of facilities that use waste as their main fuel. In addition, RD 376/2022, of May 17, which regulates the criteria for sustainability and reduction of greenhouse gas emissions from biofuels, bioliquids and biomass fuels, as well as the system of guarantees of origin of renewable gases, enables the identification and certification of gases of a renewable origin, such as biogas, biomethane or hydrogen, through the implementation of a system which is similar to that used with renewable energy. Through the GO, each MWh of renewable gas produced will lead to the emission of a guarantee of origin containing information on where, when and how the gas was produced.

SPAIN

FINANCIAL INCENTIVES (continued)

Taxation	Various tax measures for sustainability were established under Act 15/2012, of 27 December 2012: • Electricity generation tax over the total income received from the power generated by each of the taxpayer's installations at a tax rate of 7%. This electricity generation tax was suspended during the last quarter of 2018 and the first quarter of 2019, by means of Royal Decree-Law ("RDL") 15/2018, of 5 October 2018, on urgent measures for the energy transition and the protection of consumers ("RDL 15/2018"), The tax was also suspended during the third quarter of 2021 by RDL 12/2021, of June 24. This suspension was then extended by other decree-laws. Specifically: ◦ It was extended to the fourth quarter of 2021 by RDL 17/2021. ◦ It was extended to the first quarter of 2022 by RDL 29/2021, of December 21. ◦ It was extended to the second quarter of 2022 by RDL 6/2022. ◦ It was extended to 31 December 2022 by RDL 11/2022. In addition, RDL 11/2022 introduced a modification to the calculation of the taxable base, establishing that when the sale of energy from an installation takes place between related persons or entities, the taxable base may not be lower than the market value, understanding as such the one that *'would have been agreed by independent persons or entities under conditions that respect the principle of free competition'*. ◦ It has been extended until 31 December 2023 by RDL 20/2022, of 27 December. • Tax on the radioactive waste produced as a result of the generation of nuclear power and on the storage of nuclear waste in centralised plants. • Creation of the 'green cents' on natural gas, fuel-oil, coal and diesel. Since the entry into force of RDL 15/2018, this special tax on hydrocarbons does not tax electricity generation within power stations or the cogeneration within combined heat and power stations. • Duty on hydroelectric water. This duty was annulled by the Supreme Court in several rulings issued in 2021; however, it was later reinstated by Law 7/2022, of 8 April, on waste and contaminated soils for a circular economy.
Other	N/A

Endnotes

1. Expected capacity.

SWEDEN

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind- , solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030[1] Target for renewable energy	Share of electricity generation from renewable energy sources ("RES") (2020): • Hydro power: 45% • Solar power: 1% • Wind power: 17% • Bio power: 7% • Total: 70% Target for 2040: 100% of power generation from RES.
	Key generators of renewable energy	Vattenfall, Fortum, Statkraft, Skellefteå Kraft
	Pre-qualifications	There are currently no pre-qualifications
FINANCIAL INCENTIVES	Feed-in tariffs	Apart from the Electricity Certificate System (see below), there are no subsidies for renewables.
	Green certificates (name of the scheme)	The Electricity Certificate System (*Elcertifikatsystemet*) (not granted for facilities commissioned after 31 December 2021).
	Taxation	Carbon dioxide tax, energy tax, fuel taxation, etc.
	Other	N/A

Endnotes

1. Sweden only has a target for 2040.

SWITZERLAND

OVERVIEW	Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2035[1] Target for renewable energy	**2021:** 67.2% of the electricity generated in Switzerland came from renewable sources: • Hydro: 58.9% (35,355GWh) • Solar: 4.73% (2,839GWh) • Waste: 1.99% (1,194GWh) • Wood/biogas: 1.34% (804GWh) • Wind: 0.24% (144GWh) Target 2020 for renewable energy under the Energy Strategy 2050 (without hydropower): 4,400GWh (achieved). Target 2035 for renewable energy under the Energy Strategy 2050 (without hydropower): 11.400GWh. Target 2035 for hydropower under the Energy Strategy 20250: 37.400GWh.
	Key generators of renewable energy	• Alpiq Group, Axpo Group, BKW Energie AG, Repower AG, EWZ • Swiss Federal Railways (ie SBB) • EnAlpin • Groupe E • Industrielle Werke Basel (ie IWB) • Energie Wasser Bern (ie EWB)
	Pre-qualifications	There are no pre-qualifications in Switzerland.
FINANCIAL INCENTIVES	Feed-in tariffs	In 2009, the Feed-in Tariff ("KEV") system was introduced to promote the generation of electricity from renewable energy sources ("RES"). It supports numerous facilities generating electricity from RES, including hydropower (1 to 10MW), photovoltaics ("PVs"), wind energy, geothermal energy, biomass, and waste material from biomass. The KEV-system faded out at the end of 2022 (whereby applications on the waiting list will continue to be processed). The KEV-system was replaced with a system of one-time investment contributions and contributions to operation costs.
	Green certificates (name of the scheme)	The power companies sell certified green energy to consumers upon request. There is no mandatory green certificate model in Switzerland.
	Taxation	Since 1 January 2022, the CO_2 fee is CHF120 per tonne of CO_2.
	Other	N/A

Endnotes

1. Switzerland have set a target for 2035 instead of a target for 2030.

TURKEY

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	In 2020 the percentage of energy generation from renewable sources was 42.5% of the total electricity generation according to the Energy Market Regulatory Authority's ("EMRA") Electricity Market Report (2020). The breakdown of the overall electricity generation is: • Hydro-power: 25.6% • Wind-power: 8.1% • Solar-power: 3.7% • Geothermal: 3.3% • Biomass: 1.8% There was no 2020 target for renewable energy, but the Ministry of Energy and Natural Resources' ("MENR") targets for 2023 include increasing the installed capacity as follows: • Solar-power capacity to 10,000MW • Wind-power capacity to 11,883MW • Hydro-power capacity to 32,037MW • Geothermal capacity to 2,884MW
Key generators of renewable energy	There is no publicly available data with respect to key generators of renewable energy and there is no key generator for renewable energy in Turkey. According to EMRA's Electricity Market Report (2020), Elektrik Üretim AŞ, the state-owned generation entity, generated 18.97% of the total licenced electricity generated in 2020, while 82.03% of the total licensed electricity is generated by private companies. The breakdown of key generators of licenced electricity in 2020 is: • EÜAŞ: 18.97% • build-operate-transfer power plants: 0.15% • power plants the operation rights of which have been transferred: 2.68% • other private companies: 78.20%
Pre-qualifications	For a more efficient use of Renewable Energy Resource Areas ("RERA"), the MENR adopted the Regulation on Renewable Energy Resource Areas ("RERA Regulation"). This regulation regulates the determination of RERA as well as the competitive process to obtain the usage rights in these areas. To participate in competitions to be organised under the RERA Regulation, applicants are required to fulfil the conditions contained in the announcement for the competition; the RERA Regulation does not provide a list of these conditions. Those who are entitled to apply for a pre-licence under this regulation must fulfil the conditions required to obtain a pre-licence under the Electricity Market Licence Regulation.

TURKEY

Feed-in tariffs	The Law on Utilisation of Renewable Energy Resources for the Purpose of Generating Electrical Energy ("RER Law") governs the Renewable Energy Resources Support Mechanism ("RERSM"). This mechanism contains a guaranteed feed-in tariff for a period of ten years. In order to benefit from RERSM, investors must obtain a renewable energy resource certificate. This certificate enables EMRA to monitor and track the power generated from a renewable energy resource, at the time the power is traded on domestic and international markets. The prices contained in the guaranteed feed-in tariff (Schedule I) were in US$. However, for plants to be commissioned after 1 July 2021, the prices are in TRY and these prices are less than their US$ equivalent in the previous feed-in tariff. The guaranteed feed-in tariff (Schedule I) for the plants to be commissioned after 1 July 2021 is as follows (these prices are subject to adjustment every three months):

Schedule I

Type of Renewable Energy Resource-Based Generation Facility	Prices applicable (TRY/kWh)
Hydroelectric generation facility	0.40
Wind power-based generation facility	0.32
Geothermal power-based generation facility	0.54
Biomass based generation facility	0.32 – 0.54
Solar power-based generation facility	0.32

Green certificates (name of the scheme)	• International Renewable Energy Certificate ("I-REC") • Renewable Energy Guarantee of Origin ("YEK-G") The legal framework governing the YEK-G scheme entered into force on 1 June 2021 and the first day of trading was 21 June 2021. The system is similar to the I-REC. Under this scheme, the Turkish energy market operator, EPİAŞ, assumes the role of issuing the YEK-G certificates. Owners of electricity generation facilities can register their facilities with the YEK-G system (if not already registered with the I-REC system). The YEK-G certificates are traded in the YEK-G market. The participants of this market are generators of renewable electricity and suppliers, and they redeem the YEK-G certificates. Accordingly, end-users can purchase the YEK-G certificates by approaching the participants.
Taxation	Renewable energy facilities, related roads, and transmission lines established in a forestry area or on State Treasury land benefit from 85% discounts on land allocation, lease or utilisation fees for ten years, provided that generation facility is commissioned by 31 December 2025. In addition, there was an exemption from stamp duty for transactions at the investment stage of generation facilities, provided that the facility was commissioned until 31 December 2020. The facilities may also benefit from general investment incentives containing exemptions from VAT and customs duties.
Other	If the mechanical and/or electro-mechanical equipment used in the renewable energy generation facilities are manufactured in Turkey, the prices in another schedule (defined as Schedule II under the RER Law) will be added to the prices given in Schedule I (above) for five years. Additional incentives can be given by a Presidential Decree.

UKRAINE

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	Under the Energy Strategy until 2035 adopted in 2017, Ukraine aims to achieve a 10% and 25% share of RES in total electricity generation by 2025, and 2035, respectively. The electricity generation system in Ukraine includes nuclear power plants ("NPPs"), thermal power plants ("TPPs"), hydro power plants ("HPPs") and hydroelectric pumped storage power plants ("HPSPPs"), and RES producers (wind, solar and biofuels). In 2021, NPPs accounted for 55.1% of electricity generation, TPPs accounted for 29.3%, HPPs and HPSPPs and accounted for 6.7%, RES producers accounted for 8% and others for 1.1%. The breakdown within the RES producers is: (i) 19.40% - wind plants, (ii) 77.79% - solar plants, and (ii) 2.89% - biofuel plants.
Key generators of renewable energy	The power plants owned by the following companies/groups are key generators of renewable energy in Ukraine: • DTEK • Scatec Solar • Eurocape • CNBM • Windkraft
Pre-qualifications	The following documents are required for an auction pre-qualification procedure (the auction system has not yet been launched and the list of pre-qualifications may be updated closer to the launch). To participate in the auction, the bidders must submit, among other things: (i) documents confirming secured land rights (title or land-use rights in respect of the land plot(s) suitable for development and maintenance of a power plant), (ii) executed grid connection agreement, and (iii) the irrevocable bank guarantee in favour of the guaranteed buyer in the amount of €5/kW. Performance Guarantee: Following completion of the auction and before the pre-Power Purchase Agreement ("PPA") is executed, the winner must provide another irrevocable bank guarantee in favour of the guaranteed buyer in the amount of €15/kW to ensure the construction of the project. Additional Guarantee: The winner undertakes to commission a power plant within: (i) two years upon the execution of the pre-PPA (for the solar), or (ii) three years upon the execution of the pre-PPA (for the wind). The winner may extend the commissioning deadline for one year, subject to the provision of additional performance guarantee in the amount of €30/kW.

UKRAINE

Feed-in tariffs	Feed-in tariff: The feed-in tariff system remains available for those solar and wind producers who have: • commissioned their plants before 2020; • executed pre-PPA by 31 December 2019 and commissioned plants within two years from the date of a pre-PPA for solar power plants, three years for other types of RES; or • for solar plants with less than 1MW capacity and wind plants with less than 5MW capacity. The amount of feed-in tariff varies depending on the following configurations and may differ for each launch stage of the power plant: • type of alternative energy source • commissioning date of the energy generating object • capacity of the energy generating object The period of feed-in tariff support is until 2030. Local content Premium: If the power plant was constructed using a certain share of raw materials, consumables, fixed assets of Ukrainian origin ("Local Content"), the respective producer of electricity is eligible for a premium payment. Only those power plants that were commissioned starting from 1 July 2015 and have secured a feed-in tariff are eligible for the increase of the feed-in tariff as the result of satisfying the Local Content conditions. If the Local Content of the power plant exceeds 30%, 50% or 70%, the feed-in tariff may be increased by 5%, 10% or 20% respectively. The period of Local Content Premium is-equal to the feed-in tariff period. Auctions: Starting from 2022, a quota auction system will be implemented, instead of a feed-in tariff system. State support will be provided under the auction support system through a guaranteed purchase of all electricity produced by the RES project within the limits of the quota purchased at the auction at the fixed tariff established within auction process. The period of auction support is expected to be for 20 years from the date of the respective auction. Feed-in Premium: On 26 August 2021, the Ministry of Energy presented a draft law providing for the right of RES producers to freely sell electricity on the market with the possibility of receiving a margin between the established feed-in tariff or tariff fixed through auction process and market price (“Feed-in Premium” system).
Green certificates (name of the scheme)	N/A
Taxation	No specific regulation.
Other	There is a purchase guarantee for producers of electricity who enjoy the feed-in tariff. A guaranteed buyer must purchase all electricity generated from RES by a producer who (a) benefits from the feed-in tariff or has obtained state support through the auction system, and (b) is a member of the balancing group of renewable energy producers who benefit from the feed-in tariff.

UNITED KINGDOM

OVERVIEW

Percentage of energy generation from renewable sources with breakdown (wind-, solar-, hydro-, geothermal power, biofuels, waste to energy etc) and 2030 Target for renewable energy	**2021**: Renewable energy accounted for 74% of total UK electricity generation: • bioenergy: 32.7% • onshore wind: 24% • offshore wind: 29% • hydro: 4.5% • solar: 9.9% (Source: BEIS, UK Energy in Brief 2022) **2030 target**: 95% from low carbon sources
Key generators of renewable energy	• SSE • Infinis • EDF Renewable Energy • RWE • Drax • E.ON • Orsted
Pre-qualifications	Applications for participation in the capacity markets must be for a capacity type that falls into the definition of a capacity market unit ("CMU"), which is any of the following: • a 'generating CMU', which is electricity generation or electricity storage as defined in Capacity Regulations that can be either capacity which is already built or capacity which is not yet built; • a 'demand side response ("DSR") CMU', which can be either already operational or equipment that will meet these conditions prior to the commencement of the delivery year for which capacity market support is awarded; • an 'interconnector CMU', which is any international 'electricity interconnector'. For the capacity markets, only that part of the interconnector situated within GB jurisdiction qualifies. The interconnector can be either commissioned or not yet built; • a relevant CMU located in GB or GB's offshore area with a connection capacity of 2MW or more (subject to a very narrow exemption, allowing a 500kW minimum for generation-derived DSR participating in the second DSR specific transitional auction).

FINANCIAL INCENTIVES

Feed-in tariffs	**Summary**: feed-in tariff ("FIT") for small-scale generation of up to 5MW and 10MW for ground mounted solar. The scheme was closed to new applications from 1 April 2019 subject to limited grace periods for some installations which were commissioned before this date. **Mechanism**: under the terms of the licence, larger suppliers are required to agree terms for the payment of the FIT with eligible generators, including households. The tariff comprises a payment for each unit generated and an additional payment for export, calculated by reference to tariff tables set out in each supplier's licence. Generators can elect to sell their export independently. **FIT based on CfD**: the Government has enacted powers to introduce FITs for large-scale renewable and other low carbon generation which will take the form of long-term contracts for difference ("CfD"), entered into with a central government counterparty, ie the Low Carbon Contracts Company ("LCCC").
Green certificates (name of the scheme)	**Summary**: The Renewables Obligation ("RO") is an obligation placed on licensed suppliers to supply a certain amount of the electricity they generate from renewable sources in each year. The RO scheme closed on 31 March 2017, with the exception of new solar photovoltaic generating stations above 5MW, for which the scheme closed from 1 April 2015. **Note**: the Non-Fossil Fuel Obligation ("NFFO") is no longer open to new generators but will continue to operate alongside the RO until all fixed-price contracts entered into under that scheme (ie the NFFO) expire (2019); there is an equivalent regime applicable in Scotland.
Taxation	**Electricity Generator Levy**: the levy is a temporary 45% charge in effect from 1 January 2023 until 31 March 2028 which applies to electricity generated from renewable, nuclear and biomass sources. It does not apply to pumped hydro or battery storage. Briefly, the charge (levy) is levied on exceptional receipts generated from the production of wholesale electricity. The levy is limited to generators whose in-scope generation output of electricity exceeds 100GWh per annum and applies only to the exception element of receipts over £10 million in a qualifying period.
Other	N/A

Notes

Notes

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