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PREFACE

We are pleased to present the 8th edition of *Global Legal Insights – Energy*. The book contains 30 country chapters, spanning the six major continents of the world and providing a truly international and far-reaching snapshot of energy policy, industry and regulation across the globe.

The book is designed to provide general counsel, financial institutions, government agencies and private practice lawyers with a comprehensive insight into the most important trends and developments in the energy market across a range of key jurisdictions. The energy industry is never static, with both the industry and policy and law-makers constantly responding to new challenges and opportunities.

This year has been pivotal for the energy industry across the globe: 2019 saw growing discussion around climate change and sustainability issues, giving momentum to the energy revolution that has been unfolding in recent years. This has been reflected in the policy and regulatory developments in various countries. As the energy transition is further embraced and gains pace in the coming years, with new developments in technology, we are likely to see an ever-increasing rate of change in government policy and regulation, making this both an interesting and challenging time for anyone involved in the energy industry.

In producing *Global Legal Insights*, we have gathered together the views and opinions of a group of leading energy practitioners from around the world in a unique volume. The authors were asked to provide personal views on practical issues, policy issues, strategic issues, and legal and regulatory issues in their own jurisdiction, with a free rein to decide the focus of their own chapter.

One of the attractions of comparative analysis is that developments in one jurisdiction can inform understanding and practice in another.

Our thanks to all the authors for their contributions, and particular thanks to our colleague Justyna Bremen for her invaluable help. We hope that this book will prove interesting and stimulating reading for you.

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Angola

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Introduction

Angola is sub-Saharan Africa's third-largest economy, and has a vast amount of natural resources with tremendous energy potential, although there is still a long way to go in terms of the development of the energy sector. The Government has set as the major targets for this sector: an increase in access to electric power for all the Angolan population; and the promotion of renewable sources of energy, with several projects currently in the pipeline, focused mainly on hydropower and natural gas.

Overview of the current energy mix, and the place in the market of different energy sources

According to the Ministry of Energy and Water (MINEA), Angola's current installed capacity is estimated at 5.01 GW. The total generation capacity of the country was supposed to reach 6.3 GW by the end of 2018, comprising 64% hydropower (4 GW), 12% natural gas (750 MW) and 24% other fossil fuels (1.5 GW). But the Government of Angola only expects to reach this capacity once the Soyo Combined Cycle Plant (750 MW, natural gas), and the Laúca Hydroelectric Power Plant (2.1 GW) are fully operational.

Angola has its eyes set on the Angola Energy 2025 Plan, which envisages a new and more developed country that has the necessary energy infrastructure to compete on the global stage. The plan starts with the goal of bringing electricity to about 50% of the population by 2022 and 60% by 2025; a big increase when compared to the current 42% rate.

It is expected that by 2025 the demand for power will increase more than four times, reaching a load of 7.2 GW, mainly due to a 60% electrification rate, along with electricity consumption *per capita* tripling. Even though big strides are being made in the energy sector, the rural electrification rate only amounts to about 6%, meaning that there is still a great deal of improvement to be made.

Hydro and gas power plants account for 75% of the country's total energy consumption, which has been accompanied by a 25% reduction in diesel-driven electricity consumption. Following the Angola Energy 2025 plan, the government has been dedicating a lot of time to the promotion of renewable energy.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

<u>The Angola 2025 Energy Plan</u>

In the first trimester of 2019, the Angola 2025 Energy Plan was launched, which provides a high-level overview of the policies intended to increase access to electricity to 60% of the population, with 70% of electricity expected to be derived from renewable sources. In this context, a boost in investment in renewable energy projects is expected.

Solar

The Angola 2025 Energy Plan sets a target of 800 MW of installed renewable capacity by 2025, focusing primarily on solar projects. Angola has a high solar resource potential, with an annual average global horizontal radiation of between 1.350 and 2.070 kWh/m^2/year.

In the same vein, at the end of 2018, the Angolan Ministry of Energy and Water (MINEA) presented the "Scaling Solar" programme, an initiative carried out by the World Bank aimed at promoting private investment in on-grid PV solar projects in Africa in the period 2018-2022. According to public statements made by MINEA representatives, several sites are already identified for the construction of solar power plants, and all of the country's regions have favourable conditions for large-scale renewable energy projects, although so far only a limited number of off-grid projects have been implemented across the country, mostly in the provinces of Zaire, Bié, Lunda Norte, Lunda Sul, Moxico, Cunene, Huíla, Cuando Cubango and Cuanza Sul.

Hydro

The Angola 2025 Energy Plan also focuses on the hydroelectric potential of the country. In fact, Angola has exceptional hydro resources, with 159 sites identified in previous studies as having potential for large hydropower plants, in addition to those already under construction. The 2025 Energy Plan focuses greatly on this natural advantage, and MINEA plans to grow Angola hydropower generation capacity, from its current levels of around 1,200 MW, to 9,000 MW by 2025. In addition, there are still many locations suitable for micro-hydro which would have the potential to generate an estimate of 600 MW each.

To support the development of hydroelectric projects, the GAMEK (Gabinete de Aproveitamento do Médio Kwanza), the utility company responsible for implementing and managing the hydro projects in the Kwanza river, was expanded to include oversight of the development and construction of most major power projects in the country.

Renewables

The national strategy for new renewables is strongly committed to biomass as an alternative energy source, with a target of 500 MW by 2025. The Government's strategy in this sub-sector is mainly focused on hydrothermal projects with 300 MW, which take advantage of existing forest areas in the central region of the country.

1st Angola International Renewable Energy Forum

On June 19, 2019, the 1st Angola International Renewable Energy Forum was held in Luanda, organised by the Private Investment and Export Promotion Agency (AIPEX). The main goal of this event was to promote actions aimed at attracting foreign investment to the energy sector, particularly in production with renewable resources such as solar, hydro, biomass and wind. This was a remarkable initiative that could positively impact foreign investment in this sector in the near future.

Developments in government policy/strategy/approach

Pursuant to the Angola 2025 Energy Plan, the Government has set out a two-fold action plan: on the one hand, the electrification of the main populated areas through the electricity grid; and on the other hand, the provision of energy services based on decentralised solutions for rural and dispersed populations across the country. Regarding energy supply from interconnected systems, a goal was established to increase electricity coverage from 30% to 60% by 2025.

With respect to energy sources, there has been a clear investment in renewable sources of energy, with around US $18 billion worth of investments into renewables under way. Private investment in the sector is expected, along with the gradual update of electricity tariffs, to which the recent implementation of the new tariff regime will contribute with the creation of a financially self-sustaining sector.

The Government expects to substantially reduce public expenditure on energy projects, especially given its current budgetary constraints, and the economic downturn. In this context, public financing is to be directed only towards projects in the public sphere (large dams, national transport network). In fact, the key to achieve the goals set out in the Angola 2025 Energy Plan is to further expand private investment.

In this context, Angola has been making the necessary changes in its governing policy and legislation in order to create a far better environment for private investment. In addition to the review of the energy sectorial legislation, these changes came in the form of anti-corruption policies, the adoption of many economic and financial reforms, and a reduction of bureaucracy.

One of the main issues to tackle in the near future are the four energy systems – the northern, central, southern and eastern systems – spread throughout Angola that need to be connected with each other and with neighbouring States. However, this venture will cost about US $1,800 million and the government has opened its doors to private investment to fund the project. As of yet, only the northern system (Luanda) is connected to the central system. Thus, the goal is to develop the southern system so as to allow it to be connected to Namibia and the East as far as Zambia.

Aside from this investment, there are other projects that encompass the Democratic Republic of Congo, through the province of Cabinda. Angola has already started to show a surplus in energy production, meaning that the challenge now is to ensure the excess energy reaches all the Angolan population, and to eventually also sell energy to neighbouring countries.

The Government has also been engaged in multilateral organisations in order to fulfil the goals established for the energy sector. In this context, Angolan utilities are members of the Southern Africa Power Pool (SAPP) and the Central Africa Power Pool (CAPP). Angola intends to integrate into SAPP through the development and implementation of power generation projects with a regional impact, namely the Laúca Hydroelectric Power Plant, the Soyo Combined Cycle Plant, the Cambambe I and II hydroelectric plant, and the Hydroelectric of Caculo-Cabaça. Angola also intends to develop the interconnection of the transmission line with Namibia, to initially provide electricity to cities in the south of Angola.

In addition, as part of the Government's strategy of development of renewable energy projects, the Sustainable Energy Fund for Africa (SEFA), managed by the African Development Bank (AfDB) has approved a US$1 million grant to Independent Power Producers (IPP) in Angola to promote private investment in renewable energy. These funds will be used to establish a one-stop shop unit known as the Energy Project Implementation Support Unit (EPISU) that will work as a facilitator to improve the bankability of projects. In addition, this unit also aims at increasing capacity-building by providing technical assistance on project procurement, contract design, implementation and monitoring of IPP projects in Angola.

In July 2019, Angola joined the Lusophone Compact, an MoU signed by Portugal and the AfDB in November 2018, aimed at enhancing the development of the private sector in the African Portuguese Speaking Countries (PALOP) in several areas, including renewable energies.

Developments in legislation or regulation

Electricity

In 2014, under the US $1 billion African Development Bank Electricity Sector Transformation Program Loan, the Angolan energy sector went through major reforms, aimed at continuing the restructuring process started by the Energy Sector Development Strategy, approved by Resolution No. 21/02, and the National Energetic Safety Policy and Strategy, approved by Presidential Decree No. 256/11.

By means of Law No. 14-A/96, of 31 May, the General Electricity Act, which establishes the legal regime for the generation, transmission, distribution and commercialisation of electricity in Angola, was approved. In November 2014, Presidential Decree No. 305/2014 established the unbundling of the energy sector, which created three public entities operating under the Ministry of Energy and Water (MINEA): PRODEL, (*Empresa Pública de Produção de Electricidade*), the national production company; RNT (*Rede Nacional de Transporte de Electricidade*), the national transmission company; and ENDE, (*Empresa Nacional de Distribuição de Electricidade*), the national distribution company.

The General Electricity Act was amended in 2015, aiming at ensuring major participation of the private sector and clearly signalling a change in the Angola Government's policy for the energy sector. The main changes introduced by this amendment concern the liberalisation of the commercialisation of electricity, and the provision of economic incentives for investment in renewable energy sources, thus making room for greater private investment. In addition, the 2015 amendment has also created the National Rural Electrification Fund, a public entity responsible for promoting the electrification of the rural areas, which, as noted above, is one of the bigger issues in the Angolan energy sector.

The licensing procedures, permits/authorisations required to carry out these activities, and main rights and obligations of the relevant entities, are dispersed in the legislation. Most of these statutes have still not been adapted to the new market model introduced by the General Electricity Law, where electricity production is one of the activities of the value chain available to private investors, who establish a commercial relationship with the entity responsible for the management of RNT through a Power Purchase Agreement (PPA).

In this respect, the Angolan Government has recently carried out a revision and creation of sector regulations, in order to enhance private investment in the energy sector. Thus, a new Presidential Decree, aiming at regulating in one piece of legislation all the activities of the value chain of the energy sector, has been prepared and is currently out for public consultation. In addition, this draft Presidential Decree also includes a Model of Power Purchase Agreement for Renewable Energy, aligned with international best practices in the energy sector.

In May 2019, there was a significant change in electricity prices due to the enactment of Executive Decree No. 122/19, of 24 May, which established a new tariff system for electricity utilisation. Among others, this statute provides for rules regarding the protection of vulnerable consumers, by means of the provision of clearer rules regarding the allocation of subsidies. This change was mainly established to make sure that subsidies would only benefit more vulnerable consumers; however, public opinion on this matter has been mainly negative as electricity prices have nearly doubled since the implementation of this new tariff regime, in July 2019. This modification to the tariff regime goes hand in hand with the strategy of the Angolan Government of slowly reducing public expenditure in the energy sector, leaving room for the private sector to fill its place.

Natural gas

The Angolan Government has recently approved a new legal framework for the exploitation of natural gas reserves, which until now has been governed by the petroleum regulations. Indeed, the Legislative Decree No. 7/18, of 18 May establishes the legal and fiscal regime applicable to the activities of prospecting, research, evaluation, development, production and sale of natural gas in Angola. The purpose of this Legislative Decree is to create a legal and fiscal regime base that fits and promotes the exploitation of natural gas, as well as the related industries.

Private investment

Foreign investment in the Angolan energy sector is expected to be enhanced by the new legislation on private investment, under which the generation and distribution of electricity is one of the priority sectors. This inclusion seeks to attract foreign investors, as it will allow them to be granted special benefits, in particular tax benefits, irrespective of the amount of such investments.

Judicial decisions, court judgments, results of public enquiries

To the best of our knowledge, there is no available case law, judicial decisions, court judgments or results of public enquiries in Angola on the interpretation and application of the relevant legislation of the energy sector.

Angola often refers to Portuguese court decisions, but, in the energy sector, no court decisions have been issued.

Regarding public enquiries, no relevant results are available. Nevertheless, as mentioned above, a draft Presidential Decree, regulating in one piece of legislation all the activities of the value chain of the energy sector, has been prepared and is currently under public consultation.

Major events or developments

Hydro

Regarding ongoing projects, it is worth mentioning that the last two turbines of the Laúca hydroelectric project (which is the largest civil engineering project ever in the country and the second-largest dam in Africa), with a capacity of 333 MW of power each, are due to start operating by the end of the year. The major project in the pipeline in this sub-sector is the Caculo Cabaça Hydroelectric, located in Kwanza Norte province and financed by Chinese Government loan, which has an installed capacity of 2,171 MW and is expected to be, within five years, the largest dam in Angola.

New rivers and basins have also been identified by the Government as having a significant hydroelectric potential, such as the River Queve with the Balalunga and Cafula projects, and the River Catumbela with the Cacombo, Lomaum 2 and Calengue projects, and other smaller hydro projects throughout the country.

Wind projects

The Government has decided to limit the Tombwa wind project to the outflow capacity of the planned infrastructures, having in addition selected two medium-size projects with favourable conditions in areas close to the main network: one in Cuanza Norte and another near the city of Lubango.

Gas to power projects

The Soyo Combined Cycle Thermal Power Plant, which produces energy through the use of natural gas from several Angolan oil blocks, and which is currently the largest gas turbine power station project in Africa, has recently started producing and supplying electricity to the city's public grid.

Proposals for changes in laws or regulations

The main change required in the Angolan legal framework on the energy sector concerns the creation of laws and regulations that are aligned with the central principles established in the General Electricity Act and enhance private investment and the bankability of energy projects.

The first step to achieve this goal has been taken with the draft Presidential Decree that is currently under public consultation. In fact, one of the major issues in the Angolan legal framework on the energy sector relates to the large number and diversity of laws and regulations, most of them outdated and not in line with Government strategy for the sector. Therefore, it is expected that this Presidential Decree will centralise all the activities included in the energy value chain in one single piece of legislation. The inclusion of model PPA in this Presidential Decree is also a step further to achieve the legal certainty that is decisive for private generators to obtain finance and therefore to develop projects.

In order to attract the private financing sector, which plays a pivotal role in the development of an energy project, investors need to be sure that their investment will be reasonably protected against non-market risks. Therefore, a clear legal and regulatory framework protecting investors, providing guarantees, legal stability mechanisms or other measures that protect investments in the event of changes to the regulatory framework, is highly needed.

Another aspect concerns the procurement processes, which are often time-consuming, governed by the general rules on public procurement and under which the private investor bears a considerable level of risk. Thus, the creation of specific procurement procedures for energy projects (in particular, for renewable energy projects), which limits the discretion of the Government in the negotiation of concession agreements and PPAs, whilst ensuring competitiveness and transparency, would contribute to the creation of a favourable environment for private investment.

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Argentina

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Introduction

Argentina is the second-largest producer of natural gas and the fourth-largest producer of crude oil in Central and South America, based on 2017 production.[1]

In 2018, the United States Energy Information Administration estimated Argentina's proved reserves of natural gas at 12 trillion cubic feet, and the country's proved reserves of crude oil at 2.2 billion barrels.[2]

In the coming years, having a primary energy matrix strongly focused on hydrocarbons, it will be necessary for Argentina to increase operating and service capacity related to the oil and gas industries. In order to satisfy the increasing demands of the upstream, midstream and downstream, it will be essential to contract equipment, chemical products, industrial safety equipment and engineering services as well as to develop specific software, among many other products.[3]

According to the Argentine Investment and Trade Promotion Agency (*Agencia Argentina de Inversiones y Comercio Internacional*), there is more than US$ 175bn in investment opportunities in shale and offshore oil and gas, notably the development of the vast, technically recoverable reserves of the Vaca Muerta formation.[4]

In this article we provide an overview of the legal framework, summarise the key regulatory and policy developments, and highlight the business opportunities in Argentina's oil and gas sector.

Legal framework

The Hydrocarbons Law No. 17,319 (the "Hydrocarbons Law") sets forth the basic legal framework for the regulation of oil and gas exploration and production in Argentina. It authorises the Argentine national government to establish a national policy for the development of Argentina's hydrocarbon reserves, with the principal purpose of satisfying domestic demand.

<u>Exploration permits and exploitation concessions</u>

According to the Hydrocarbons Law, exploration for and production of oil and gas is carried out by means of exploration permits, production concessions, exploitation contracts or partnership agreements. The Hydrocarbons Law also permits surface reconnaissance of territory not covered by exploration permits or production concessions upon authorisation of the Government Secretariat of Energy (the "SGE" for its Spanish acronym) and/or competent provincial authorities, as set forth by Law No. 26,197, and subject to the permission of the private property owner. Information resulting from surface reconnaissance must be shared with the SGE and/or competent provincial authorities, which cannot disclose this information for a period of two years without the permission of the party who performed the reconnaissance, except in connection with the granting of exploration permits or production concessions.

Relevant authorities

Under the Hydrocarbons Law, the federal and/or competent provincial authorities may grant exploration permits after the submission of competitive bids. Permit holders have the exclusive right to carry out necessary and appropriate gas and oil exploration operations within the area specified by the permit. Each exploration permit may cover only unexplored areas not exceeding 10,000 km^2 (15,000 km^2 for offshore exploration) and may have a term of up to 11 years resulting from two consecutive basic terms of three years each and an extension period of five years, provided the investment commitments have been properly fulfilled (13 years for offshore and unconventional exploration permits, resulting from two basic terms of four years each and a five-year extension). Law No. 27,007, which applies to exploration permits issued on or after October 31, 2014, sets forth permit terms of up to 11 years for conventional objectives and 13 years for unconventional objectives and offshore exploration.

Commercial discovery

In case of discovery of commercially exploitable amounts of oil or gas, the permit holder has the right to obtain an exclusive production and development concession. The terms of newly awarded oil and gas production concessions are 25 years for conventional, 35 years for unconventional (of which the initial five-year period shall include a Pilot Plan to be agreed with the relevant authority), and 30 years for offshore oil and gas from the date of the award of the concession, in addition to any remaining exploration term at the date of such award. The Hydrocarbons Law further sets forth that concession terms may be extended for periods of up to 10 additional years each, subject to terms and conditions approved by the awarding authority at the time of the extension, which may include the payment of an extension bond.

Pursuant to Law No. 26,197, the power to extend the terms of current and new permits and concessions has been vested in the governments of the provinces in which the relevant block is located (and in the Argentine national government, in case of offshore blocks beyond 12 nautical miles). The extension is subject to the concessionaire having complied with all of its obligations under the Hydrocarbons Law, including but without limitation: evidence of payment of taxes and royalties and compliance with environmental, investment and development provisions; production of hydrocarbons in the area at issue; and presentation of an investment plan to develop the concession. A production concession also grants its holder the right to conduct all necessary and appropriate oil and gas production activities, subject to such activities not interfering with other exploration permits and production concession holders' activities. Finally, a production concession also gives its holder a right to obtain a transportation concession for the oil and gas produced.

Exploration permits and production concessions require holders to perform all necessary work to find or extract hydrocarbons, using appropriate techniques complying with all applicable federal, provincial and municipal regulations, as well as to make specified investments.

Royalties

Under the Hydrocarbons Law, production concession holders are also required to pay royalties to the province where production occurs. Royalty rates are set at a maximum of

12% (whereby 3% will be added for each extension up to a maximum of 18%). They are payable on the value at the wellhead (equal to the price upon delivery of the product, minus transportation, treatment costs and other deductions) of crude oil production and natural gas volumes sold. These royalty rates may be reduced taking into account productivity and the type of production at issue. Notwithstanding the aforementioned, for concessions extended prior to the entering into force of Law No. 27,007 on October 31, 2014, the previous conditions remain valid.

Export duties

On January 8, 2017, export duties on hydrocarbon exports established by Law No. 26,732 ceased to be enforceable. However, in the framework of the financial assistance agreed with the International Monetary Found, on September 4, 2018, customs duties were established on the export of hydrocarbons through Decree No. 793/2018. The export tax rate was increased to 12%, with a cap of 3 or 4 pesos per dollar, depending on the product.

Under the Hydrocarbons Law, any oil and gas produced by an exploration permit holder prior to the awarding of a production concession is subject to the payment of a 15% royalty.

Surface fee

Furthermore, Sections 57 and 58 of the Hydrocarbons Law require exploration permit and production concession holders to pay an annual surface fee based on the acreage of each block, which varies depending on the phase of the operation, such as exploration or production, and in the case of the former, depends on the relevant period of the exploration permit. These amounts were updated by Law No. 27,007 and may be partially adjusted as from the second basic exploration period in light of investments actually carried out.[5]

Permits and concessions termination

Exploration permits, and production or transportation concessions, may be terminated upon occurrence of any of the following events: (i) failure to pay annual surface taxes within three months of the due date; (ii) failure to pay royalties within three months of the due date; (iii) substantial and unjustifiable failure to comply with specified production, conservation, investment, work or other obligations; (iv) repeated failure to provide information to, or facilitate inspection by, authorities or to utilise adequate technology in operations; (v) in the case of exploration permits, failure to apply for a production concession within 30 days of determining the existence of commercially exploitable quantities of hydrocarbons; (vi) bankruptcy of the permit or concession holder; (vii) death or end of legal existence of the permit or concession holder; or (viii) failure to transport hydrocarbons for third parties on a non-discriminatory basis or repeated violation of the authorised tariffs for such transportation.

Under the Hydrocarbons Law, a defaulting concessionaire must be given a cure period, whose duration is to be determined by the SGE and/or the competent provincial authorities, prior to termination.

Upon expiry or termination of a production concession, all oil and gas wells, operating and maintenance equipment and facilities automatically revert to the province where the reservoir is located, or to the Argentine Republic in the case of reservoirs under federal jurisdiction, without compensation to the concession holder.

Concession term extension

The granting of an extension is an unregulated process and typically involves lengthy negotiations between the applicant and the relevant government. Although the Hydrocarbons Law, as amended, requires that applications be submitted at least one year prior to the concession expiration date, it is general industry practice to start the process much earlier, generally as soon as the technical and economic feasibility of new investment projects beyond the concession term become apparent.

Production disposition – limits and restrictions

Holders of production concessions have the right to produce and own the oil and gas they extract and are allowed to freely sell such production in the domestic or export markets, subject to certain conditions (Hydrocarbons Law, Article 6, 1st paragraph; Decree 1,589/1989, as amended by Decree 1,277/2012).

The Hydrocarbons Law authorises the National Executive to regulate the domestic oil and gas markets and to limit the exports during any period in which domestic production is insufficient to satisfy domestic demand (Articles 3 and 6, 2nd and following paragraphs).

If the National Executive restricts the export of hydrocarbons and/or byproducts, refiners and exporters shall receive a price not lower than that of imported products of similar quality.

When the prices of imported products increase significantly due to exceptional circumstances, domestic prices may be fixed on the basis of the real operating costs of the State-owned company, the corresponding amortisations, and a reasonable interest on the updated and depreciated investments (Hydrocarbons Law, Article 6, 2nd and following paragraphs).

Key regulatory and policy developments

In late 2014, the Argentine government implemented a major hydrocarbons reform providing investors with offshore exploration opportunities, and encouraging foreign ventures in unconventional oil and gas projects. Furthermore, reforms to the national bidding process were introduced in order to attract private sector investment in the upstream oil and gas industries and boost domestic energy supplies. These reforms consisted in more frequent offshore licensing rounds, longer exploitation periods, and tax exemptions for companies with an investment volume higher than US$ 250m over a three-year period.

In 2016, natural gas and electricity public utilities tarifs were reviewed and augmented drastically by the Argentine government in an attempt to reduce historically high subsidies for consumers. Contemporaneously, prices corresponding to natural gas and electricity distributed by public utilities were increased jointly with the gasoline prices. The government is trying to narrow Argentina's energy supply gap by completely eliminating natural gas and electricity subsidies by the beginning of 2020, raising domestic energy prices in order to attract the necessary investment in production and becoming energy self-sufficient, among other measures.

Finally, the Argentine government successfully negotiated terms between labour unions and natural gas producers and eliminated currency controls at the beginning of 2017. The government also extended the natural gas production stimulus programs implemented in 2012, and set a minimum price on wellhead natural gas production until 2020.

Business opportunities

Although Argentina's oil and gas sector ranks near the top in Central and South America, it still presents big development opportunities. Large investments are required to fully capitalise on its potential. Argentina has conventional oil and gas resources across the country with a history of strong production. There are also vast and high-quality known unconventional oil and gas resources that are still in the early stages of development, the most important among these being the Vaca Muerta formation. Due to its long history in oil and gas, Argentina has already attracted a large number of companies (currently there are more than 50 operations and service providers in the country) which generated a large human capital and know-how in the oil and gas sector. Currently, the sector employs more than 100,000 qualified personnel.

Vaca Muerta formation

Argentina holds the second-largest shale gas and fourth-largest technically recoverable shale oil reserves in the world. A very large portion of these reserves is held by the Vaca Muerta formation, which is located in the Nequén Basin on the territories of the Provinces of Neuquén, Mendoza, La Pampa and Río Negro. According to the Argentine Investment and Trade Promotion Agency (*Agencia Argentina de Inversiones y Commercio Internacional*) Vaca Muerta presents a US$14–15bn per year investment opportunity to reach its full production potential.[5] Its relative thickness (around 1,000ft) and lateral extension (7,700 million acres), jointly with good values of permeability and pressure, make it a high-quality resource compared to other world class basins. Vaca Muerta is favourably located in a desert with very low population density and, since the Neuquén Basin is also a conventional field, oil and gas services and transport are already in place.

Vaca Muerta's stakeholders have agreed to improve its productivity and a working group has been set up consisting of high-profile public and private participants with the aim of accelerating its development and competitiveness. Concessions have already been allocated (exploration: 4+4 years with an optional additional period of 5 years / exploitation: 35 years with unlimited 10-year extensions), but local operators are looking for operational and financial partners who possess the necessary know-how in unconventional explorations (partnership types could include farmout agreements, M&A, JOAs, among others).

YPF, Argentina's largest integrated oil and gas company, holds around 40% of Vaca Muerta and is open to exploring partnerships under Integrated Project Team structures (IPT).

In addition, G&P, the oil and gas company fully owned by the Province of Neuquén, has launched the fifth bidding round of its Neuquén Exploratory Plan tender for joint venture agreements. The plan encompasses 46 areas of approx. 330 km^2: each area has exploratory wells that are already drilled and/or of which 2D/3D seismic surveys are available. Interested parties will be invited to perform geological and geophysical (G&G) studies, with open tenders every quarter.

Offshore oil and gas basins

Argentina has seven offshore oil and gas basins totalling aproximately 500,000 km^2. This area, however, could grow noticeably, taking into account that the United Nations has granted Argentina's request to expand its continental shelf by more than a third of its current size.

The deep-water Austral Basin near the Province of Tierra del Fuego, in the very south of Argentina, is considered to have the greatest potential, whereas the remaining basins still require further seismic studies to determine their potential.

In October 2018, by means of Decree No. 872/2018, the SGE was instructed by the national government to call for public international tender for the adjudication of exploration permits in search of hydrocarbons in the Argentine offshore areas. Mindful that the Argentine continental platform and its diverse constituent exploratory basins are under-explored and with less than 1% of the surface under concession, as well as in light of the necessity to make major investments in new exploration technologies that are available, the SGE held that it is necessary and appropriate to take steps aimed at furthering the knowledge, exploration and production of the offshore areas, by means of effective investments in seismic survey and exploration works. To this effect, it was considered suitable to establish a programme of calls for rounds of International Public Tenders with the objective of awarding exploration permits in Offshore Areas. Concessionaires awarded with an operation concession will claim royalties on the production of the concession between 5% and 12%, depending on the level of development of the respective projects (the percentage is calculated annually according to the formula set out in Annex II of Decree No. 872/2018).

From 2019 onward, it is planned to have one public international tender per year.

Oil and gas infrastructure

According to the Argentine Investment and Trade Promotion Agency (*Agencia Argentina de Inversiones y Comercio Internacional*), oil and gas-related infrastructure present an US$ 4–5bn investment opportunity, to fully absorb the sector's increased production activity.

Argentina is expected to need significant infrastructure investments to keep pace with its expanding oil and gas exploration and production capacity. New infrastructure includes: the extension of Argentina's pipeline network; the construction of additional treatment facilities; and the improvement and expansion of the national freight rail network to meet Vaca Muerta's gathering needs, which present significant opportunities for midstream companies. Specifically, it is intended to connect Vaca Muerta with the large international seaport of Bahía Blanca (Atlantic Ocean) by railway.

Electricity market

Argentine undertook an extensive privatisation programme in 1991 (including in the electricity sector). The privatisation was based on Laws No. 23,696 (State Reform Law), issued in 1989, and No. 24,065 (Electricity Regulatory Law, issued in 1992), and created the National Regulatory Commission for Electricity (*Ente Nacional Regulador de la Electricidad* – ENRE); the provinces of Argentina have adopted their own regulatory frameworks in similar terms. As result, the Electricity Regulatory Framework aims to:

- promote competition;
- encourage investments;
- reduce the rates paid by final consumers;
- protect consumer rights;
- improve the quality of service; and
- promote efficiency, reliability and open access.

The legal framework divides the sector's activity into the generation, transmission and distribution of electricity, as segregated businesses subject to different requirements and regulations. (The segregation of activities was imposed in light of the natural monopoly that can occur in the transmission and distribution and competition markets regarding the production and marketing of electricity.) The generators, distributors, transmission companies, large users and brokers are agents of the Wholesale Electric Market ("WEM"). The WEM is regulated by the Secretariat of Renewable Resources and Electricity Market, and electricity generators, distributors and other agents can buy and sell electricity in spot transactions or under long-term supply contracts at prices determined by the forces of supply and demand.

Electricity distribution and transmission is a public service, while generation is an activity of general interest. Long-term concession agreements are granted by the federal or provincial governments to distributors, transmission companies and hydroelectric power plants. Large users are admitted as members of the WEM and operate in this market through power purchase agreements ("PPAs") directly agreed with the generation companies.

Tariffs for distributors and transmission companies are nominated in US dollars, and are adjusted twice a year according to US indexes with the final approval of the regulatory entities (federal or local). Generators operate in an open market and are dispatched under the marginal cost principle. This means that the most cost-efficient generator is the first to be dispatched, and energy is sold at marginal cost (that is, the hourly cost of energy at the WEM when it is sold, as calculated by CAMMESA (*Compañía Administradora del Mercado Mayorista Eléctrico SA*), the WEM administration company).

The WEM is wholly interconnected by more than 32,000 kilometres of high-voltage (500 kV) and medium-voltage (220 kV and 132 kV) transmission lines and related facilities (together forming the National Interconnection System). There are two high-voltage international interconnections to Chile and Brazil. The distribution sector is composed of:

- Two distribution companies (Edenor and Edesur) that operate in the federal jurisdiction.
- Provincial distribution companies operating in each of the 23 provinces.
- Minor scale distributors or "co-operatives" (*cooperativas*). Many of these operate within the various municipalities' jurisdictions.

Recent trends

Due to the breach of concession agreements and power generation remuneration rules, public utilities rates and wholesale prices were virtually frozen and kept artificially below costs, creating a structural deficit in the operation of the WEM (covered by means of subsidies paid by the National Treasury to CAMMESA).

This led to the electricity emergency declaration by the new federal government (which took office in December 2015) from 15 December 2015 until 31 December 2017. The Ministry of Energy and Mining (currently the Governmental Secretary of Energy) was made responsible for:

- Preparing and putting in place a plan of action to address the issues with electricity generation, transportation and distribution to improve their quality and safety, and to ensure the supply of electric power under suitable technical and economic conditions.
- Working with other agencies of the Argentine Government to develop a programme for the efficient use of energy.

Under the said framework, a call was made for bids for thermal generation capacity and associated electric power generation (Resolution No. 21/16, issued by the former Secretariat of Electric Energy under Decree No. 134/15 and Resolution No. 6/16 (issued by the former Ministry of Energy and Mining)). The energy was to be made available in the WEM to meet essential demand requirements in various periods between 2017 and 2018.

Since then, distributor and transmission concessionaires carried out their Integral Tariff Review (*Revision Tarifaria Integral*) and are therefore currently expanding their networks to cover the demand. National authorities are in the process of reducing the electricity subsidies that helped meet the demand during the previous administrations, and are increasingly overcoming the deficit in the national budget caused by the subsidies.

Legal framework

The electric power sector is regulated by the following:

- Law No. 15,336 (enacted on 20 September 1960), as amended by Law No. 24,065 (passed on 19 December 1991), partially promulgated by Decree No. 13/92, and regulated by Decree No. 1398/92 and Decree No. 186/95 ("Regulatory Framework").

- Law 24,065 implemented the privatisation of government-owned companies in the electric power sector and unbundled the industry vertically into generation, transmission, distribution and demand. Law 24,065 also reorganised the WEM based on the guidelines in Decree No. 634/91.
- Decree No. 186/95 also introduced the concept of participants, which includes traders (defined as a company that is not a WEM agent but trades electric power).

A set of regulatory provisions called the Procedures for the Programming of Operation, Dispatch and Price Calculation were issued through Resolution No. 61 of 29 April 1992 (by the former Secretariat of Electric Energy). The Procedures have since been amended, supplemented and extended by subsequent resolutions issued by the former Secretariat of Electric Energy.

Relevant authorities

The ENRE was set up as an autonomous entity under the former Secretariat of Electric Energy (currently, the Governmental Secretary of Energy). ENRE's main responsibilities are to:

- enforce the Regulatory Framework, control the rendering of public services and the performance of the obligations under the concession contracts at a national level;
- regulate WEM agents;
- set the basis for calculation of tariffs and approve the tariff schedules of transmission and distribution companies holding national concessions;
- authorise electrical conduit easements;
- authorise the construction of new facilities; and
- resolve disputes between WEM agents. Such disputes are subject to the prior compulsory jurisdiction of ENRE (and are subject to further judicial review).

The Executive authorised ENRE's board of directors (via an open call (*convocatoria abierta*)) to select ENRE's current members.

The main regulator is the Governmental Secretary of Energy, which is the successor to the former Ministry of Energy and Mining and the previous Secretariat of Electric Energy. The Secretary's main responsibilities in relation to the electricity sector are to:

- participate in the drafting and implementation of national energy policies;
- enforce the laws governing the development of the activities within its scope of competence;
- participate in the drafting of policies and regulations governing public services within the scope of its competence;
- oversee the entities and agencies governing works and public service concessionaires;
- engage in drafting regulations concerning licences issued by the federal government or the provinces for public services within the scope of its competence;
- oversee the regulatory entities and agencies of privatised areas or areas operating under concessions within the scope of its competence; and
- enforce the Regulatory Framework and oversee the regulations governing tariffs, fees, duties and taxes.

The Secretariat of Renewable Resources and Electricity Market has specific duties about the WEM, which are:

- to assist the Secretary of Government in the exercise of his duties as the regulatory authority for electricity;
- to participate in the development of sectoral proposals and national policy on renewable resources and electric power, and in their implementation;
- to understand the formulation of the tariff policy in the public services of transportation and distribution of electricity;
- to study and analyse the behaviour of the wholesale electricity market, monitor the relationships between its different players and assist in the development of the rules that regulate its operation;
- to participate in the short- and medium-term management of the wholesale electricity market, the incorporation of new players, the definition of the operation and contracting modalities within the scope of said market, and assist in the procedures for the authorisation of import and export of electrical energy;
- to assist in the elaboration of the regulation of the electric power transport activity and in the definition of the projects, procedures and financing of the expansion of the transmission network;
- to promote the use of new energy sources, the incorporation of conventional hydroelectric supply and applied research in these fields;
- to co-ordinate relations with the entities of the different jurisdictions and with the regulator of national jurisdiction;
- to participate in the preparation and supervision of the execution of international and inter-jurisdictional cooperation and integration agreements in which the Nation is a party, and coordinate relations with binational and international entities in the electricity sector;
- to assist the Secretary of Government in the exercise of the powers that correspond to the rights derived from the shares owned by the National State-Secretariat of the Ministry of Energy and Mining in companies with activity in the electric energy sector; and
- to act as representative of the Government Secretariat in the Federal Council of Electric Power.

CAMMESA is a not-for-profit corporation. Its shareholders each hold 20% stakes and are the:

- Argentine Government (represented by the Governmental Secretary of Energy); and
- four associations representing the different segments of the electric power sector (generation, transmission, distribution and large users).

CAMMESA is managed by a board of directors composed of ten regular directors and up to ten alternate directors (appointed by its shareholders). Each of the associations that represent the different segments of the electric power sector can appoint two regular directors and two alternate directors. The two remaining regular directors of CAMMESA are:

- The Undersecretariat of Electric Energy. He/she serves as chairman of the board by virtue of the delegation made by the former Ministry of Energy and Mining.
- An independent member who acts as vice chairman and is appointed at a shareholder

meeting. The decisions adopted by the board of directors of CAMMESA require the affirmative vote of a majority of the directors present at the meeting and the affirmative vote of the chairman of the board.

CAMMESA is responsible for:

- Managing the Argentine Interconnected System (*Sistema Argentino de Interconexión*) under the Regulatory Framework. This includes:
  - determining the technical and economic dispatch of electric power (including determining the schedule of production of all generation plants of a power system to balance production with demand);
  - maximising system security and the quality of the supplied electricity;
  - minimising wholesale prices in the spot market;
  - planning energy capacity requirements and optimising energy use under the rules periodically set out by the Secretariat of Electric Energy; and
  - monitoring the operation of the futures market and administering the technical dispatch of electric power under the agreements entered into on that market.
- Acting as an agent of the WEM participants.
- Purchasing and selling electric power from or to other countries by performing the relevant import/export transactions under the existing agreements between Argentina and its bordering countries, and/or among WEM agents and third parties from bordering countries.
- Carrying out the commercial administration and dispatch of fuels for the WEM generation plants.
- Acquiring and supplying fuel for the electric power generation plants which deliver the generated electricity to the Argentine Interconnected System (this is a temporary responsibility).

CAMMESA's operating costs are funded by the mandatory contributions of the WEM participants. The maximum amount for CAMMESA's annual budget is currently set to 0.85% of all WEM transactions planned for each year.

The provincial regulatory authorities regulate the electrical system in their territories and have their own enforcement authorities.

The provincial regulatory bodies grant and oversee electricity distribution concessions. However, if a provincial electric power market participant is connected to the Argentine Interconnected System, it must also comply with federal regulations. Provinces have generally followed federal regulatory guidelines and have established similar regulatory institutions. Isolated provincial electric power systems are very rare, and most provincial market participants are connected to the Argentine Interconnected System and buy and sell electric power in the WEM (which is regulated by the Argentine Government).

Electricity generation (whatever its source), transformation and transmission (but not distribution) are exclusively regulated by the federal authorities if they:

- relate to national security;
- are to be used in the trade of electricity between different provinces and districts inside the country (that is, between two different provinces, or between the City of Buenos Aires and a province);
- are exclusively under the jurisdiction of the Argentine Congress;

- relate to hydroelectric or tidal energy facilities and must be connected with them (or with others of the same or different source) for them to be efficiently used;
- are connected to the Argentine Interconnected System;
- relate to the trade of electricity with a foreign nation; or
- relate to electric power plants that use or transform nuclear or atomic energy.

Exclusive federal jurisdiction implies that provinces have limited taxing and supervision powers in terms of generation, transformation and transmission facilities of electricity.

Generation

As a result of privatisation and incorporation of new market players, the generation sector has a competitive structure of private and State-owned companies (even after the consolidation process of the past few years).

Transmission

Transmission activities are regulated as public services as they are natural monopolies (Law No. 24,065). The Argentine authorities have granted concessions to private entities involved with transmission activities, subject to certain conditions (such as service quality standards and fixing the tariffs transmission companies can charge for their services).

Electricity transmission is comprised of:

- A high-voltage transmission system (operated by Transener, a private company). This connects the main electricity production and consumption areas allowing transmission between different Argentine regions.
- Several regional trunk systems. These transmit electricity in a particular region and connect the generators, distributors and large users in that region.

Transmission services are rendered by concessionaires that operate and use high- and medium-voltage transmission lines. Transmission services consist of the transformation and transmission of electric power from generators' delivery points to distributors' or large users' reception points. Energy transmission companies must be independent from other WEM participants and cannot purchase or sell electricity (Law No. 24,065).

Distribution

Electricity distribution is regulated only at the federal level for the City of Buenos Aires and the districts in the metropolitan area of Greater Buenos Aires.

EDENOR operates in the northern area of both the City of Buenos Aires and Greater Buenos Aires, and EDESUR operates in the southern area of both the City of Buenos Aires and Greater Buenos Aires.

In the rest of the country, the electric power distribution service is regulated at the provincial level and is subject to concessions granted by provincial authorities.

Supply

Concessions granted to electricity distribution companies include the selling of electricity directly to users. However, large end users can buy electricity directly from the electricity generator connected to the Argentine Interconnected System via the WEM.

Vertical integration limits

To preserve competition in the electricity market, participants in the electricity sector are subject to vertical and horizontal restrictions, depending on the market segment in which they operate.

The following vertical restrictions apply:

- A generation company (and its subsidiaries or its holding company) cannot be an owner, majority shareholder, or controlling entity of a transmitter company.
- A holder of generation units cannot own distribution concessions. However, the shareholders of the electricity generator can own an entity that holds distribution units (as shareholders of the generator or through any other entity created to own or control distribution units).
- A transmission company (and its subsidiaries or its controlling entity) cannot be an owner, majority shareholder or holding company of a generation company.
- A transmission company (and a company controlled by, or controlling, a transmission company) cannot be an owner, majority shareholder or holding company of a distribution company.
- Transmission companies cannot buy or sell electricity.
- A distribution company (and its subsidiaries or its holding company) cannot be an owner, majority shareholder or holding company of a transmission company.
- A distribution company cannot own generation units. However, the shareholders of the electricity distributor can own generation units (directly or through an entity created to own or control generation units).

Large users can enter into power purchase agreements directly with generation companies or with traders (at freely agreed prices and conditions). A fee is paid to the local distributor for the use of its distribution network.

<u>Renewable energy</u>

In recent years, Argentina has prioritised the generation of electricity from renewable sources. Therefore, it has issued a specific legal framework intended to regulate and incorporate electricity generated from renewables into the WEM, and has promoted it by granting incentives (tax benefits and preferential or subsidised tariffs).

To promote renewable energy, Law No. 26,190 was enacted in December 2006. This approved the national promotional regime for the use of sources of renewable energy destined for electricity production (Promotional Regime). Law No. 26,190 (as amended by Law No. 27,191) aims to increase national electric power consumption from renewable energy to 8% by the end of 2017, and 20% by the end of 2025. This law also establishes a system of investment for the construction of new plants intended to generate electric power from renewable energy sources, which will remain in force for 10 years from its enactment (that is, until 2025).

This system incentivises individuals and legal entities to invest in renewable energy generation projects (with the approval of the regulator). The electricity must be delivered to the WEM.

Law No. 26,190 was amended by Law No. 27,191 on 23 September 2015. The amendments seek to establish a legal framework to increase investments in renewable energies and encourage electricity generation diversification (increasing the renewable sources ratio).

The Promotional Regime provides for important tax benefits.

Endnotes

1. *BP Statistical Review of World Energy*, June 2018.
2. https://www.eia.gov/beta/international/?fips=AR.
3. http://www.aogexpo.com.ar/2017/en/general_information/market_information.
4. *Agencia Argentina de Inversiones y Commercio Internacional*, Selected Investment Opportunities, September 2018.
5. These amounts were updated by Law No. 27,007 and may be partially adjusted as from the second basic exploration period in light of investments actually carried out:

   Holders of the exploration permits shall pay annually and in advance, for each square kilometer or fraction, the following surface fees:

   - First Basic Term: Ar$250.
   - Second Basic Term: Ar$1,000.
   - Extension first year: Ar$17,500.
   - Following: Ar$17,500 plus an additional 25% per year (which may be offset with proven investments up to 90% of the corresponding fee).

   The amounts were increased by Law No 27,007 with the goal of incentivising exploration and development of these areas.

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Agustín Siboldi joined O'FARRELL in 1998 after acting as an internal counsel in another strongly regulated sector (telecom) and Partner since 2007. He teamed up the energy areas of practice as from 2002, increasing since then his participation in the field, advising on regulatory, contractual and litigious affairs regarding upstream, midstream and downstream activities as well as power generation, transmission and distribution.

He also represents several energy companies in connection with antitrust matters and was strongly involved in the drafting of the amendment to the Hydrocarbons Law in October 2014.

He has intensive academic activity in the main law and business schools of the City at post degree levels with focus in natural resources and economic regulation; author of an important number of publications in the field.

Agustín Siboldi is a member of *Instituto Argentino de Petroleo y Gas* – IAPG; the *Instituto Argentino de Energía General Mosconi*; Association International Petroleum Negotiators –AIPN; International Bar Association – IBA– in the Energy and Antitrust Committees; American Bar Association in the Energy and Antitrust Committees; Secretary of the Board of Directors of C.A.D.E.R. (Argentinean Renewable Energy Chamber).

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Austria

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Overview of the current energy mix, and the place in the market of different energy sources

The Austrian internal energy supply is based on a balanced mix of energy sources. About one-third of the energy needed is produced in Austria and the rest is imported. Around 80% of the internal Austrian primary energy production is based on renewables, mostly from biomass and hydro. Imports consist mainly of hydrocarbons.

Therefore, the primary energy sources used to cover Austrian energy consumption are diverse: in 2018 approximately 36.7% oil; 21.8% gas; 29.2% renewable energies; 8.2% coal; and 182% combustible waste were used. The remaining 2.3% comprises net imports of electricity. The production of nuclear energy was banned in 1978 according to the Federal Law for a non-nuclear Austria.

This shows that in Austria hydrocarbons (oil and gas) are still the most-consumed primary energy sources. Oil and gas are produced in Austria in economically relevant quantities. The annual production volume of oil and gas covers about 10% of the respective domestic demand. For the rest, Austria relies on imports. To ensure security of supply, a broad diversification of sources is desirable. In 2017, the oil imported came from 13 different countries; Kazakhstan, Iraq and Azerbaijan were listed as the most important delivering countries.

While the consumption of heating oil decreased by 12.5%, the consumption of diesel and petrol increased by around 1.6%. This also confirms that the highest percentage of final consumption of oil is related to the transport sector, at almost 80%.

Over 50% of natural gas is imported from Russia, followed by Norway and Germany. Internal consumption has decreased compared with other energy sources in recent years, mainly owing to a reduction in the use of natural gas in thermal power generation. Natural gas is still very popular in household heating, however, and also used for district heating. Thermal power generation based on natural gas is also necessary as back-up for power shortages and stabilisation of the network.

Among renewable energies, hydropower and biomass make up around 73% of the total renewable end energy produced in Austria. Owing to political efforts and the promotion of renewable energy, there are several other renewable energy sources that have gained importance over the past few years, including wind energy, geothermal energy and solar energy.

Analysing the energy market, it is notable that Austria's energy market gets more and more competitive: 331,500 electricity and gas consumers – both households and companies – changed their electricity or gas supplier in 2018, the second-highest number of changes since liberalisation began. In 2018, the change rate for electricity was 4.1%, and for gas 6.1%.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The energy situation in Austria has not changed dramatically in the recent year. A reduction in the consumption of hydrocarbons can be seen, and a recent increase of production of electricity from photovoltaic and windfarms, but from a very low level. Changes in the climate, however, become more and more evident and thus account for increasing public pressure on politicians to enact effective measures against fossil fuel consumption and increase the production and use of clean energy. In the recent election to the European Parliament in 2019, the Green Party, which had lost seats in the Austrian Parliament only about two years earlier, made an exceptional resurgence on the political scene, gaining more than 14% of votes.

This influenced the political debate. Now, all parties currently involved in the election campaign for the re-election to the Austrian Parliament in September 2019, which was dissolved prematurely, have included effective measures to deal with climate change in their manifestos. It remains to be seen what measures a newly elected parliament will invoke.

The measures debated range from more effective promotion of renewables and the removal of obstacles to electric mobility, to energy efficiency, etc., in line with the recently enacted new European legislation (see below).

Developments in government policy/strategy/approach

Austria must fulfil both the European energy policy-related objectives and its own energy strategy aims. In June 2019, the EU has enacted a comprehensive update of its energy policy framework to facilitate the transition away from fossil fuels towards cleaner energy, and to deliver on the EU's Paris Agreement commitments for reducing greenhouse gas emissions.

The completion of this new energy rulebook – called the Clean Energy for all Europeans Package – marks a significant step towards the implementation of the energy union strategy, adopted in 2015. It is focused on the promotion of energy efficiency, security of supply, the development of renewable energy and reduction of carbon dioxide at the same time.

To act in line with the new EU energy package, the government of Austria initiated a climate and energy strategy called "#mission2030" in June 2018, setting out strategies to cope with the ambitious 2030 targets. It postulates the objective to reduce CO_2 emissions by 36% compared to 2005. So far, a reduction in the amount of 8% has been achieved. To reach this goal, 10 projects were presented including the expansion of E-mobility for cars and trains, and financial support for private persons installing photovoltaics. The strategy's progress is constantly examined by evaluations, which can lead to adjustments to this strategy. Several amendments to existing statutes will need to be enacted to provide these projects with a legal foundation.

In many areas, however, this mission statement did not include concrete steps to achieve the goals.

In December 2018, Austria submitted to the European Commission its integrated national energy and climate plan, in accordance with Regulation (EU 2018/1999) on the Governance of the Energy Union and Climate Action. In June 2019, the EU Commission criticised this plan – and Austria – for not doing enough to reduce climate change. Austria's strategies on working towards the goal of a reduction of CO_2 by 40% by 2030 were deemed insufficient. In particular, EU Commissioner Miguel Aarias Canete criticised the lack of concrete information and measures on how Austria intends to reduce its greenhouse gas emissions.

Brussels also complained about a lack of information on the necessary investments and their financing, which are needed to improve the climate balance. Further points of criticism concern non-concrete plans to increase energy efficiency, and the lack of integration of agriculture.

Austria has until the end of 2019 to forward a more concrete plan to the European Commission.

As regards the objective to minimise the use of oil, the Austrian government started an initiative to support consumers, municipalities and business to switch from their oil-fired heating to systems working with renewable energy, under the headline "away from oil". There are currently around 600,000 oil-fired heating systems in Austria, which represents around 14% of all heating systems.

In 2018, 35% of applicants took up this bonus; in 2019 so far, it has been 79% of applicants. More than 6,500 households have taken advantage of this support. Due to its great success, this initiative will be continued. Together with the ban of oil heating in newly built homes under provincial building laws, this initiative will lead to an effective reduction of oil-fired heating systems in Austria.

Developments in legislation or regulation

Based on Commission proposals published in November 2016, the Clean Energy Package for all Europeans consists of eight legislative acts. All of the new rules have been enacted by mid-2019; EU countries, including Austria, have one to two years to transpose the new directives into national law.

The changes will bring considerable benefits from a consumer perspective, from an environmental perspective, and from an economic perspective. They also underline EU leadership in tackling global warming, and provide an important contribution to the long-term strategy of achieving carbon neutrality by 2050 proposed by the EU.

After the European Commission presented its climate and energy policy in November 2016, under which all European member states would be required to further reduce greenhouse gas emissions and to increase energy efficiency by 2030, Austria passed a minor green electricity amendment package, which included several amendments in various Austrian laws. This package simplified administrative procedures, and increased their efficiency. It also focused on the promotion of solar systems by adjusting rules and regulations, enabling the joint construction and operation of solar system plants at apartment houses that provide an independent electricity power plant for multiple households living in such buildings. Moreover, additional funds were made available for wind power plants, solar system plants, small hydropower plants and biomass plants.

However, this amendment package did not aim at an overall adjustment of the Austrian renewable funding regime to the EU-Commission's guidelines of environmental state protection and energy aid, nor at responding to other structural problems. Therefore, a major amendment package, establishing cost efficiency and competitiveness as crucial factors for getting funds, is envisaged in order to comply with the European legislation after 2020. The successor to the current Green Electricity Act aims to fulfil the obligations of the "Clean Energy Package" of the European Commission, especially to achieve "100% renewable energy in the electricity sector by 2030" (for more details, see below).

In order to accelerate the permitting process for major projects in December 2018, the Location Development Act was passed. This law enables the Federal Government to confirm the special public interest of the Republic of Austria in individual projects that serve the (further) development of the business location to an extraordinary degree. As a result, various measures are derived. If a decision on such a project is not issued by the environmental impact assessment authority (EIA authority) at the latest 12 months after submission of the application, the Administrative Court has – in case of a complaint by the project applicant – to issue a decision concerning this licensing process. This should also expedite energy infrastructure projects, such as the high-voltage transmission lines that are needed to further develop the Austrian electricity grid in order to cope with new developments and ensure security of supply.

The Network and Information Systems Security Act, passed at the end of 2018, implements the Network and Information Security Directive of the European Union. The aim is to achieve a high level of security for network and information systems. In particular, national coordination structures for the prevention and management of security incidents and computer emergency teams to support the "operators of essential services" – including the energy sector – will be set up.

Regarding the gas market, the tasks of the Market Area Manager (MAM), have been integrated with those of the Distribution Area Manager (DAM), combining these two functions in one administrative unit. The bundling of responsibilities creates synergies and a one-stop-shop for market participants in the market area 'east', which comprises seven of Austria's nine provinces.

Judicial decisions, court judgments, results of public enquiries

Decisions of the Austrian regulatory authority, E-Control Austria, can be challenged with the Federal Administrative Court, with ongoing appeal to the Constitutional Court and the Highest Administrative Court, depending on the issues raised. Fines due to an infringement of energy laws are imposed by the competent district general administrative authority. Such decisions can be challenged in front of the competent Provincial Administrative Court, with subsequent appeal possibilities – again, to either the Constitutional Court or the Highest Administrative Court.

A recent decision of the Administrative Court underlined the importance of fair competition in energy law. The Court ruled that the principle of equal treatment and non-discrimination is an integral aspect of the entire energy law and is regarded as one of the core principles of the Electricity Sector Act. In the present case, a customer was urged by the employee of a grid operator to conclude electricity supply contracts with an associated company. This was judged to be a clear infringement of these core rules, which was also the reason why no "call to order" was possible; instead a fine had to be imposed.

The Federal Administrative Court recently passed several decisions with regard to tariffing and cost-determination of network operators, granting the energy regulatory authority broad discretion when it comes to commercial decisions in this respect.

Currently, the interpretation of the now applicable Green Energy Act by the entity granting the funds was highly criticised by companies. In their opinion, significantly more renewable plants could be funded and established but, due to the improper implementation of the law, not enough grant agreements have been concluded. In detail, the question is how the market price is determined to analyse the scope of the available funds. There are differences of opinion as to whether the market price in the year before the application is submitted should be used, or the market price in the year before the fund is granted. In order to achieve clarity on this matter, lawsuits are being prepared by the companies affected. Furthermore, in the last session of the National Council in Parliament, an initiative proposal on this topic concerning the Green Energy Act was proposed.

Major events or developments

Since the liberalisation of the electricity markets, Austria and Germany have both been part of a united market region in the wholesale trade of electricity. In this market, electricity has been traded on an unrestricted basis, provided that no shortages occur. As a result, there has been no difference between the wholesale prices for electricity in Germany and Austria.

Due to regular transmission shortages, electricity produced mainly from wind power in northern Germany often cannot be transported directly to the major consumption centres in the south of Germany and to Austria. This has increased the need for grid stabilisation and, consequently, the costs for measures to stabilise the grid not only in Germany and Austria, but also in neighbouring countries such as Poland and the Czech Republic. This has led to complaints by these countries to the Agency for the Cooperation of the European Energy Regulators (ACER).

To solve this problem, ACER issued an opinion proposing to separate the previously common electricity market between Germany (including Luxembourg) and Austria. This proposal was enacted in October 2018, after an agreement had been reached between the German and Austrian regulatory authorities on the terms of the capacity allocation at this new restricted border. According to E-Control, this market separation is intended to balance physical and financial flows and thereby stabilise the networks.

Notwithstanding this arrangement, E-Control challenged the opinion of ACER with the European Court of Justice and, in April 2019, energy companies filed an inquiry at the European Parliament regarding the reconnection of the newly separated electricity markets. In addition, a claim was filed at the Austrian competition court against the German transmission undertaking "Tennet", claiming that the closing of the border to Austria was against European standards, especially concerning the free movement of goods and antitrust law. According to their interpretation, a separation must only be made at the point where the transmission capacity is insufficient to satisfy all transactions needed. In this case, this would be in the centre of Germany and not on the German-Austrian border.

In order to make itself more competitive, Austria has launched a major national innovation project for innovative energy technologies in the form of a "model region", concerning the consumption and the production of energy. *New Energy for Industry* (NEFI) is a key project and was also presented to the general public during the COP24 World Climate Conference in Katowice. The goal of using innovative energy technologies from Austria to develop model solutions for intelligent, safe and affordable energy and transport systems of the future is supported with a funding budget of up to €40 million per model region. The goal is also to create value through technology development, and export "*Made in Austria*".

Proposals for changes in laws or regulations

Proposals for changes in laws from the government are suspended in Austria due to the political situation and re-election in September 2019.

Notwithstanding this, in order to fully comply with the EU directives and regulations established as part of the clean-energy-package, Austria needs to adapt several laws by 2021.

To achieve the determined goals, proposals have already been tabled by different Austrian political parties. Consent is given regarding the implementation of projects in the renewable energy sector that are already approved and qualified for funding. To support the growth of projects in the field of renewable energy, more financial resources should be made available. Existing taxes on the production and usage of self-produced renewable energy should be eliminated by 2020. In general, the production of clean energy should be made easier for consumers and businesses; tax benefits, especially, should be established.

However, it remains to be seen if the political parties can gain a majority for any of the different proposals now tabled before the Parliament, which will hold its last session before election at the beginning of September 2019.

Before the break-up of the government in spring 2019, the responsible ministry had already started work on a new Energy Expansion Act in 2018, which is intended to replace the Green Energy Act. This new energy law focuses on market rewards and investment funds. Facilitating the expansion of existing renewable energy generators and power plants, and the construction of new ones, is one of the goals. A high degree of attention is also brought to the unbundling of obsolete responsibilities and the establishment of clear regulatory and responsibility structures between the federation, states and municipalities.

Both the requirements of the EU's guidelines on state aid for environmental protection and energy, and those of the Directive on the promotion of the use of energy from renewable sources (RED II), are to be incorporated – including, for example, the switch from feed-in rates towards market premium rates. These market premiums should be established as premiums on market prices. They are intended to run for 20 years. In addition, the Energy Expansion Act should address the topics of market design, system responsibility and sector coupling. However, due to the elections in autumn 2019, this amendment package will likely not be passed before 2020.

In 2018, E-Control started a consultation process with the objective of changing the Austrian gas-balancing model. The consultation process ended at the beginning of July 2019. The objective is to achieve an integrated balancing of the entire market area east, eliminating the current systematic separation between transmission level and distribution area, and introducing a model with reduced contractual and operational complexity. The legal requirements at national level, and the requirements of the Network Code for Gas Balancing (NC BAL), must be taken into account. In particular, at the transmission level, due to the requirements of the NC BAL, the dominant *ex ante* balancing has to be replaced by an *ex post* balancing.

E-Control plans to present a revised Market Model Ordinance incorporating the changes in autumn this year. The changes should come into force in October 2021.

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Brazil

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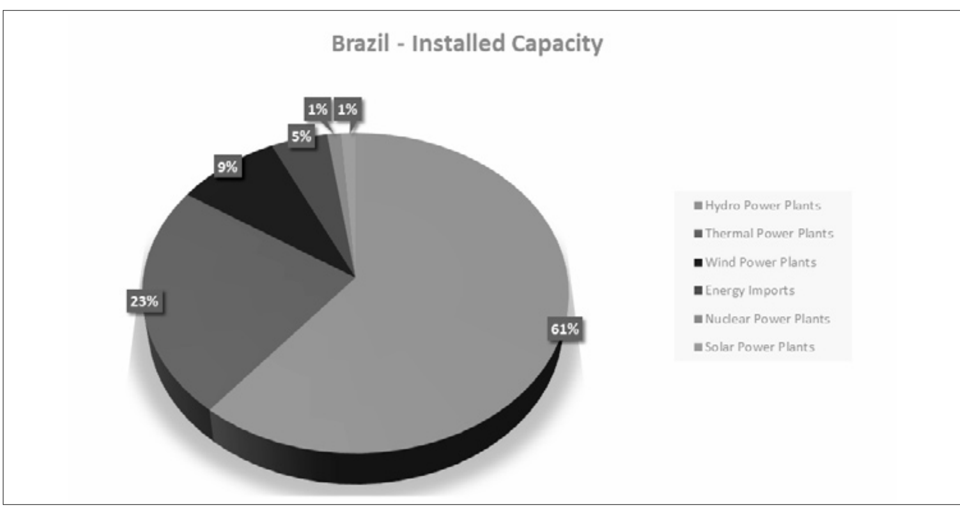
Overview of the current energy mix, and the place in the market of different energy sources

Considering that Brazil is a country with large territorial extension, the national energy mix comprises a wide range of energy sources. According to the National Electric Energy Agency ("ANEEL"), Brazil has an installed capacity of 169,678,050 kW, divided into the following energy sources: (i) 60.96% corresponds to hydro power plants; (ii) 23.29% corresponds to thermal power plants; (iii) 8.67% corresponds to wind power plants; (iv) 4.70% corresponds to energy imports; (v) 1.14% corresponds to nuclear power plants; and (vi) 1.21% corresponds to solar power plants:



Nonetheless, it is important to highlight that the Energy Research Company ("EPE") provides in its 10-year plan (*Plano Decenal* 2027) that a substantial increase of renewable energies shall take place in the Brazilian energy mix within the next 10 years. Following the expected investment of BRL 226 billion, an increase to 27GW of wind power plants and 9GW of photovoltaic power plants is predicted by 2027.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In 2017 and 2018, the Federal Government undertook the organisation of public auctions for the construction of new power plants and supply of their energy to distribution companies.

In addition, governmental authorities maintained the debate concerning the review of the legal and regulatory framework applicable to the energy sector. Together with the recovery of the national economy and stabilisation of the political crisis, such initiative was important to reignite the attention of national and foreign investors in the country's electric energy market.

Restart of public auctions and strengthening of the free market[1]

After the turbulent political crisis characterised by former president Dilma Roussef's impeachment and her subsequent temporary replacement by Michel Temer, in 2018, Brazil held new presidential elections, which resulted in the appointment of Jair Bolsonaro as the country's president.

In order to meet market demand for new energy auctions (scarce since 2014), in 2018, the Ministry of Mines and Energy ("MME") and ANEEL carried out different auctions for the sale of energy produced by thermal, hydro, photovoltaic and wind power plants within four and six years as of the auction, which resumés are presented below:

A-4 Auction			
Energy source	**Number of projects declared winners**	**Average price (R$/MWh)**	**Goodwill**
Wind	4	67.60	73.50%
Hydro	4	198.12	31.90%
Biomass	2	198.94	39.5%
Photovoltaic	29	118.07	62.2%
Total	39		

A-6 Auction		
Energy source	**Number of projects declared winners**	**Average price (R$/MWh)**
Wind	48	90.45
Small Hydro Power Plants	6	193.99
CGH	4	195.00
Hydro	1	151.68
Biomass	2	175.59
Gas-Fuelled	1	179.98
Total	62	

Together with the bids registered at the end of 2017, these bids represented the restart of the auctions system in the Brazilian energy market.

In addition to the above-mentioned procurement proceedings, the Federal Government has recently settled dates for energy auctions to be held within the next three years, in accordance with the table below:

	Type of auction	Auction date
2019	A-4	June 27
	A-6	September 26
2020	A-4	April 23
	A-6	September 24
2021	A-4	April 29
	A-6	September 30

Despite the relevant number of auctions already scheduled by the Federal Government for the next three years, entrepreneurs have faced severe competition with such bids.

In this scenario, power producers have been studying the structuring of energy projects and proceeding with their implementation exclusively or partially based on power purchase agreements executed in the free market (including agreements based on foreign currency).

Therefore, the tough competition identified in connection with the restart of public auctions has revealed a new trend for the Brazilian energy sector; namely, the strengthening of its free market.

Developments in government policy/strategy/approach

Reformulation of the legal and regulatory framework applicable to the energy sector

In July 2017, MME opened two public hearings aimed at receiving contributions from market players in order to reformulate and improve the Brazilian power sector's legal framework. The first public hearing discussed general principles and guidelines applicable to the sector, while the other discussed specific measures that could positively affect the market. These public hearings resulted in a draft Bill of Law, which is still under discussion in the Congress.

The hearings recommended the end of discounts applicable to TUST and TUSD fees (fees regarding connection to transmission and distribution systems) for new renewable energy projects, as well as discussing the impossibility of their replacement by brownfield power plants after the relevant licence term. Such recommendation was justified by the fact that Brazil already has a sustainable, developed and strong renewable energy market and, therefore, these incentives would no longer be required.

In this regard, it should be noted that Law No. 9,427/1996 authorised ANEEL to grant a discount on the TUST and TUSD fees for wind, solar, biomass and small hydro power plants, which were able to reduce costs of production and, consequently, the price of the generated energy.

Also, the hearings suggested gradual opening of the free market to new players until 2028, by means of the decrease of the access requirements from 200kW to 75kW of power consumption. The gradual opening of the free market has already been implemented by means of Ruling No. 514, issued by the Ministry of Mines and Energy on December 27, 2018, which gradually reduces the access requirements from 2.5MW to 2MW between July 2019 and January 2020.

Lastly, the hearings also recommended the possibility of the establishment of public auctions specifically for capacity sale (instead of the currently existing auctions, which purpose is to sell energy produced by power plants).

In addition to the reformulation of the regulatory framework applicable to the energy sector, Federal and State Governments implemented the sale of their participation in state-owned companies with activities in the energy sector, as detailed below.

Eletrobras: Privatisation of its distribution companies

Centrais Elétricas Brasileiras S.A. ("Eletrobras")' process of privatisation dates back to 2015, when the company refused to renew the concession agreements executed by its distribution companies of the States of Alagoas, Piauí, Roraima, Rondônia, Amazonas and Acre through the terms and conditions provided by Law No. 12,783/2013.

In this scenario, the Federal Government resumed the process of privatisation of Eletrobras' distribution companies upon the enactment of Law No. 13,334/2016, on September 13, 2016, which inserted such enterprises within the Investment Partnership Program (*Programa de Parcerias de Investimentos* – "PPI"). The PPI was established in order to define policies for investment in the infrastructure sector by means of the implementation of partnerships with the private sector.

The privatisation process consisted in the concession of the public distribution services of six Brazilian states, along with the transfer of corporate control of the distribution companies, upon the payment of a symbolic value of BRL 50,000 per concession. In addition, Eletrobras' successors would have to invest substantial amounts of resources in order to assure gains related to the distribution companies' efficiency, management and an improvement in the quality of services provided to local consumers.

Despite the judicial lawsuits filed in order to avoid the privatisation process, corporate control of the following distribution companies has already been sold via public auctions:

Distribution company	Concession successor
Eletrobras Distribuição Piauí (CEPISA)	Equatorial Energia
Eletrobras Distribuição Roraima (Boa Vista Energia)	Consortium Oliveira Energia
Eletrobras Distribuição Acre (Eletroacre)	Energisa S.A.
Eletrobras Rondônia (CERON)	Energisa S.A.
Companhia Energética de Alagoas (CEAL)	Equatorial Energia
Eletrobras Amazonas Energia	Consortium Oliveira Energia

Eletrobras: Privatisation of equity interest in power production and transmission SPVs

Along with the privatisation of its six distribution companies, Eletrobras concluded the sale of its equity interest in 71 special purpose vehicles ("SPV") that are holders of power production and transmission facilities.

Eighteen batches (*lotes*) were offered by means of public bidding, among which: (i) eight batches comprised 59 SPVs for wind power generation, with an installed capacity of approximately 1,605 MW; and (ii) 10 batches comprised 12 SPVs which operate transmission lines of approximately 2,912km of extension and 5,530 MWA of transformer capacity.

Sale of CESP's corporate control

Companhia Energética de São Paulo ("CESP") is a state-owned company created by the Government of the State of São Paulo in 1996, which today operates three distinct hydro power plants, namely UHE Porto Primavera, Paraibuna and Jaguari.

In October 2018, the State of São Paulo concluded the sale of its equity interest in CESP to a consortium formed by the Canadian Pension Plan Investment Board – CPPIB, and Votorantim Energia for BRL 1.7 billion.

Roraima's energy auction for energy supply

In addition to initiatives associated with changes to the energy sector's regulatory framework and with the role of the Government in such a market, other governmental measures regarding the development of the sector in the past months should be highlighted, such as local energy supply and efficiency auctions, as detailed further below.

On May 31, 2019, ANEEL carried out a specific auction focused on the supply of energy to the State of Roraima, considering that the state could be subject to energy supply drawbacks as a consequence of Venezuela's political crisis.

As a result of such bid, the local utilities company (Boa Vista) hired 263.5 MW to be supplied by the winning projects as of June 2021 for an average price of BRL 833/MWh. Also, as disclosed by ANEEL, the implementation of the energy projects in the State of Roraima will require investments from the bidders in the total amount of BRL 1.62 billion.

Creation of a power efficiency auction

ANEEL initiated Public Hearing No. 07/2018 with the purpose of obtaining contributions related to: (i) the definition of a concept for power efficiency auctions; along with (ii) the methodology and the assumptions to be considered in the analysis of the regulatory impacts related to a pilot project to be implemented in the State of Roraima.

Initially, the proposal consisted in holding a reverse power auction, in which ANEEL would set the annual amounts of energy consumption, to be reduced throughout the efficiency program duration. In this way, bidders would compete for the lowest price of energy by implementing a number of projects for reducing the amounts of energy consumption, such as the changing of light bulbs, refrigerators or air conditioners, implementation of distributed generation, modernisation of public lighting, among others. In this regard, it should be noted that the State of Roraima has its energy supply provided mainly by energy imports and from diesel-fuelled local generation, which is an expensive and highly polluting source of energy. For this reason, the studies within Public Hearing No. 07/2018 aimed at implementing a pilot project in Roraima, a state whose economy consumes 4MW average per year.

The contributions have already been submitted to Public Hearing No. 07/2018, however, no decisions were provided regarding the execution of a power efficiency auction in the State of Roraima up to this moment.

Developments in legislation or regulation

As mentioned previously, the National Congress is currently evaluating a Bill of Law proposal that has the purpose of reformulating the regulatory framework applicable to the energy sector. Nevertheless, other legal and regulatory changes were implemented recently in order to foster the development of the national energy market, such as discussions associated with the update of the regulation regarding distributed energy and LNG projects, as detailed below.

Distributed generation and future changes in the regulation

ANEEL has regulated, through Normative Resolution No. 482/2012 (REN No. 482/2012), micro and mini on-site generation. Such measure allows final consumers to install power generation projects (wind, solar, etc.) in their residences or on other commercial or industrial facilities, in order to offset energy with the local distributor (energy generated is injected into the grid and is used to reduce the consumption of electricity from the consumer unit). The rule is valid only for consumer units that use renewable energy sources (such as hydro, solar, biomass, wind and qualified cogeneration).

Consumers that install on-site generation systems are not allowed to commercialise the excess of energy produced by the power plant, and may only offset such exceeding energy with credits from the distribution company.

The on-site generation system may be: (i) micro systems that comprise power plants with installed capacity lower than or equal to 75kW; or (ii) mini systems that comprise power plants with installed capacity superior to 75kW, and inferior to or equal to 5MW.

Despite the increase by 167% of the Brazilian distributed generation market, the improvement of REN No. 482/2012 was included in ANEEL's Regulatory Agenda for the biennium of 2018/2019. Considering the necessity of constantly improving the regulation, the matter is being discussed within Public Hearing No. 10/2018; however, no decisions have been provided in such Public Hearing up to this moment. Among other matters, Public Hearing No. 10/2018 discusses increases in the distributed generation's limits, funding for distributed generation projects, and the impacts of such undertakings on the distribution grid. Also, currently there is a discussion on whether the structure of the residential tariffs charged by distribution companies must be modified in view of the constant increase of distributed generation projects so that the utilities companies would be able to charge such consumers the costs associated with the use of the grid.

Penalty applicable in case of lack of fuel to thermal power plants

ANEEL enacted on August 23, 2018, Normative Resolution No. 827/2018 (REN No. 827/2018), which updates the guidelines that must be observed regarding the application of penalties to thermal power plants due to lack of fuel.

Among other provisions, Resolution No. 827/2018 untied the penalty value applicable to thermal power plants from the Differences Settlement Price (*Preço de Liquidação de Diferenças* – PLD), thus basing the calculation of fines on the Unitary Variable Cost (CVU) of the respective plant.

In addition, Resolution No. 827/2018 allowed free negotiation between power producer and fuel supplier concerning the penalty to be applied in case of lack of fuel.

The alterations provided by REN No. 827/2018 follow the evolution of discussions held in ANEEL and at the National Oil & Gas Agency (ANP), and take into account the relevance of the development of thermoelectricity projects integrated with fossil fuel markets, as well as the specific supply and logistics conditions for the supply of liquid fuels.

Judicial decisions, court judgments, results of public enquiries

Through the Energy Reallocation Mechanism (MRE), each hydro power plant receives its level of generation output and shares the hydrological risks with other participants of such a mechanism.

The result of MRE depends on a monthly comparison between the energy produced by the hydroelectric generators that participate in the mechanism and the sum of their generation outputs (*garantia física* – GF). If the energy produced exceeds the total generation output, the outstanding energy amount is shared between the hydroelectric generators that produced energy below their generation output, and those participants that exceeded their level of production are financially compensated by the mechanism. If the energy produced under MRE is below the sum of all GF of the participants, the generation output of each participant is reduced in that month by the Generation Scaling Factor (GSF), which could obligate the generator to acquire energy on the spot market. The GSF is the ratio between the energy produced by the generators participating in MRE and the sum of their generation output:

GSF = total power production in MRE/sum of MRE's generators GF

In 2012, the level of water reservoirs considerably decreased, affecting the power generation by hydro power plants. In January of 2013, the GSF reached its lower level, meaning that hydroelectric generation was below the combined generation output of MRE's participants. The adverse scenario continued through 2014 and 2015, when many agents of the power sector filed lawsuits, with preliminary injunction requests, aiming at the limited application of GSF to hydroelectric generators participating in MRE.

Many of the plaintiffs in these lawsuits argued that they were bearing costs, within MRE, that had no relation to hydrologic risks, such as: (i) delays regarding the start of commercial operation of new hydro power plants; and (ii) unlimited dispatch of expensive thermal power plants. In addition, it was argued that the GSF mechanism was decreasing hydro power plants' generation outputs above the legal limit (5%), given the extraordinary context.

In this scenario, the Federal Government introduced through Federal Law No. 13,203, dated December 8, 2015 ("Federal Law No. 13,203/2015"), the mechanism called "Renegotiation of the Hydrological Risk". This mechanism seeks to mitigate the financial losses experienced by MRE's hydroelectric generators due to non-manageable exposure to hydrological risks. The Renegotiation of the Hydrological Risk works as a non-compulsory insurance for MRE's participants, and in order to enter into such mechanism, the interested agent must waive its intention to discuss hydrological risk and its impacts judicially.

Nevertheless, GSF-related discussions still present difficulties today. Firstly, the renegotiation mechanism was not sufficient to mitigate the problems hereby presented. Secondly, the Brazilian courts have conceded many of the preliminary injunctions related to the GSF conflict, impairing financial settlement of the spot market. Today, the preliminary injunctions have generated a debt of about R$ 7.18 billion in the spot market, yet to be paid.

Major events or developments

<u>Restart of public auctions</u>

As previously mentioned, at the end of 2017 and in 2018, MME and ANEEL carried out different auctions for the delivery of energy produced by thermal, hydro, photovoltaic and wind power plants within six and four years as of the occurrence of the auction.

However, since the sector players have been facing severe competition within these bids, entrepreneurs are redirecting their attention to the development of new projects exclusively or partially based in power purchase agreements executed in the free market.

For further information regarding the restart of public auctions in 2017, please refer to the section, "Changes in the energy situation in the last 12 months which are likely to have an impact on future direction of policy".

Relevant role of MCSD during the years 2016 to 2018

Due to the excess energy in the market and a number of projects facing delays associated with the start of commercial operation, the Mechanism for Compensation of Surpluses and Deficits ("MCSD") played a relevant role during the years of 2016 to 2018 in order to balance the demands of the national energy market. MCSD is a mechanism similar to an auction provided by ANEEL's regulation which allows the partial, total, temporary or definitive reduction of the amount of energy contracted under the Regulated Power Purchase Agreements (so-called "CCEARs").

MCSD was considered extremely relevant for the years between 2016 and 2018, because it allowed: (i) distribution companies with excess energy to balance their CCEARs currently in force; and (ii) projects facing commercial operation delays to keep their CCEARs.

In addition to MCSD, ANEEL has also organised an auction specifically to cancel CCEARs currently in force and has enacted a specific regulation (ANEEL Resolution No. 711, of April 19, 2016), allowing distribution companies and power producers to renegotiate the terms and conditions of their CCEARs.

Transmission companies' exemption: truck drivers' strike

On May 21, 2018, Brazilian independent truck drivers started a national strike, which would latter affect the country's entire supply chain and leave most cities without full access to basic inputs. By blocking the main highways – which are responsible for most of the input flow throughout the country – fuel distribution was severely impaired and very few companies were able to carry on with their normal activities, leaving the Brazilian economy with major financial losses. Such situation, as expected, also affected energy sector companies.

A month later, the Energy System National Operator (*Operador Nacional do Sistema Elétrico* – ONS) contacted ANEEL regarding the occurrence, during the strike period, of several concessionaires cancelling scheduled interventions on transmission systems (such as programmed corrective and preventive maintenances). A significant number of power transmission companies had not been able to perform their programmed interventions due to the lack of inputs and fuel, and such unwarned cancellations would trigger penalties pursuant to Normative Resolution No. 729/2018 (REN No. 729/2018). However, ONS argued that, considering the extraordinary circumstances, those penalties should not be applied, even though the penalty exemption hypothesis provided in REN No. 729/2018 would not embrace the situation at hand.

In this scenario, in August, ANEEL decided, in contrast to the applicable regulation, that the penalty would not be applied to cancellations that took place during the 10-day strike. The agency acknowledged that the events caused serious logistic problems that would prevent transmission companies performing their programmed interventions. In addition, ANEEL stated that energy shutdowns, which were to be held during those maintenances, were not welcome at all during that period, especially when taking into account the lack of fuel and other basic products (which had already harshly affected the national economy).

Proposals for changes in laws or regulations

Reformulation of the legal and regulatory framework applicable to the energy sector

As mentioned previously, MME opened two public hearings aimed at receiving contributions from market players to reformulate and improve the Brazilian power sector's legal framework. The first public hearing discussed general principles and guidelines applicable to the sector, while the other discussed specific measures that could positively affect the market. These public hearings resulted in a draft of Bill of Law, which is now under discussion in the Congress.

For further information regarding such Bill of Law, please refer to the section, "Developments in government policy/strategy/approach".

In addition, ANEEL is currently reviewing the regulation applicable to distributed generation in order to improve the rules associated with the implementation of this kind of project in Brazil.

* * *

Endnote

1. Differently from energy auctions, in the free market, power producers and traders can freely negotiate the price for the sale of energy to other generation companies, traders, and free and special consumers. In the regulated market, on the other hand, distribution companies buy energy from generation companies that have won public auctions organised by the Federal Government. The conditions, amounts and rates for sales of energy are determined through the auctions.

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Canada

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Overview of the current energy mix, and the place in the market of different energy sources

Canada is fortunate to have an abundant supply of energy from a wide range of renewable and non-renewable sources. Canada is the second-largest country in the world after Russia; it contains 10 provinces, and three territories that use six time zones covering four-and-half hours, and stretches from the Atlantic Ocean to the Pacific Ocean, and up to the Arctic Ocean. Because of its large size, the energy mix varies across the country, depending on the natural resources and infrastructure in the particular province or territory, and the availability of imported sources.

Canada is the fourth-largest producer and fourth-largest exporter of oil in the world, with 10% of the world's proved oil reserves (est. 167 billion barrels), and Canada can sustain current production levels of natural gas for up to 300 years with proved reserves of 69 trillion cubic feet. 98% of Canada's proven oil reserves are located in the oil sands in the Province of Alberta. Most crude oil production occurs in Alberta, but crude oil is also produced in the western provinces of British Columbia, Saskatchewan and Manitoba, and to a lesser extent in the Province of Ontario. There are also several producing offshore oil fields located in the northern Atlantic Ocean, off the coast of the Province of Newfoundland and Labrador. Canada's oil requirements are primarily met through domestic oil production.

In 2017, Canada produced approximately 4.2 million barrels of oil per day, while it consumed 1.8 million barrels of oil per day. Despite Canada's capability to meet its oil requirements through domestic crude oil production, in 2017, total crude oil imports averaged approximately 759,000 barrels per day.

It is estimated that Canada is the sixth-largest producer of electricity in the world, generating over 652 terawatt hours (TWh) in 2017, representing 3% of the world's total production. Canada is the world's second-largest producer of hydroelectricity, with 67% of its electricity coming from renewable sources, and 82% from non-greenhouse gas-emitting sources (67% from renewable sources plus 15% from nuclear).

Several provinces, including British Columbia and Quebec, rely primarily on hydroelectricity, while Ontario obtains about 61% of its electricity from nuclear power. In recent years, the Province of Ontario, Canada's most populous province, has engaged in several procurement programs to acquire electricity from wind, solar and biofuel, with the result that Ontario now obtains about 7% of its yearly electricity needs from wind, solar and biofuel; 25% from hydro power; and only 6% of Ontario's power is generated using petroleum products (gas and oil) and no power generated from coal.

Developments in government policy/strategy/approach

One of the major obstacles faced by Alberta's oil industry is the lack of pipeline capacity to transport Alberta's oil to tidewater for shipment to overseas markets. Approximately 96% of Canada's oil exports go to the United States. Canada has an extensive network of pipelines carrying crude oil to domestic and U.S. refineries, but there is very limited pipeline capacity to transport Alberta's oil to global markets via an ocean port. The lack of ability to reach global markets has resulted in Canadian oil selling at discounted prices.

In recent years, Kinder Morgan Canada Inc. proposed expanding its existing Trans Mountain Pipeline by twinning the existing pipeline system with approximately 987 kilometres of new pipeline segments for the purpose of transporting diluted bitumen from Edmonton, Alberta to Burnaby, British Columbia. The Trans Mountain Expansion Project also proposed a new and expanded dock facility at a marine terminal in Burnaby, British Columbia. Several indigenous groups (sometimes referred to in Canada as First Nations) and environmental groups filed court challenges to oppose the expansion. In addition, the provincial government of British Columbia, where the expanded dock facility is to be located, also expressed strong opposition to the Trans Mountain Expansion Project because of concerns over increased tanker traffic off British Columbia's Pacific coast. The government of British Columbia stated that it would use every tool it could to stop the Trans Mountain Expansion Project.

In August 2018, the Canadian federal government intervened and purchased the expansion project and the existing Trans Mountain Pipeline and related infrastructure for CAD $4.5 billion to ensure a vital piece of energy infrastructure will be built. As a result, the Canadian federal government is currently the owner of the existing Trans Mountain Pipeline, but the Canadian federal government will have to overcome significant hurdles before it can complete the construction of the expansion project and increase the country's ability to transport oil to tidewater for shipment to overseas markets. Although some significant regulatory hurdles have now been cleared, the pipeline expansion project continues to face significant court challenges from various groups that are opposed to its construction.

In May 2019, the British Columbia Court of Appeal rejected the Province of British Columbia's bid to restrict increased heavy oil shipments through the Province. The Province's proposed amendments to the *Environmental Management Act* were intended to prohibit the operation of the expanded Trans Mountain Pipeline in the Province until such time as a provincially appointed official decided otherwise. The British Columbia Court of Appeal unanimously held that the amendments were not constitutional because they would interfere with the federal government's exclusive jurisdiction over interprovincial pipelines. The government of British Columbia is appealing this decision to the Supreme Court of Canada for ultimate determination.

Additionally, the Federal Court of Appeal recently permitted six of twelve ongoing proposed legal challenges to the Trans Mountain Expansion project to proceed. These six legal challenges relate to the adequacy of the federal government's consultations with various indigenous communities affected by the Trans Mountain Expansion.

In a similar series of events, TC Energy, formerly known as TransCanada Corporation, proposed the Keystone XL Pipeline, which would increase Canada's export capacity to the global markets via the Gulf Coast of the United States. Keystone XL was initially rejected by the Obama administration; however, the Trump administration has since granted approval. Notwithstanding Presidential approval, several lawsuits concerning the legality of the Keystone XL approval process exist. Beyond these legal hurdles, TC Energy has yet to make a Final Investment Decision to move forward with Keystone XL.

In summary, significant hurdles to increase Canada's ability to export oil to global markets remain. As a result, Canadian oil continues to be sold at discounted prices. For example, in 2018 the Province of Alberta, which leads the provinces in crude oil production with 82% of Canada's total production, produced more crude oil than could be shipped for export by rail or pipeline. This affected storage levels and Canadian crude oil prices, which in the Fall of 2018 were discounted by over $50 to West Texas Intermediate, the benchmark U.S. grade of crude oil. To protect the value of Canadian produced oil, the government of Alberta intervened and imposed temporary limits on production to match export capacity to prevent Canadian Crude from selling at such large discounts. These temporary limits on production have been extended to the end of 2020 due to the lack of new export capacity. The production restrictions have resulted in the shutting-in of producing wells, and decreased levels of exploration and drilling activities in Canada.

Developments in legislation or regulation

Federal developments

"*Canadian Energy Regulator Act*" and "*Impact Assessment Agency of Canada*"

Canada's federal and provincial governments share jurisdiction over Canadian energy policy, as well as the legal and regulatory framework for the exploration of Canadian oil and natural gas reserves. Accordingly, there is no single energy policy or regulatory body governing the electricity industry or the development of oil and natural gas reserves in Canada.

In August 2019, the federal government implemented Bill C-69 which provides for the enactment of two new statutes that provide for the establishment of two new regulatory agencies:

1. the *Canadian Energy Regulator Act* established the Canadian Energy Regulator (the "CER") to replace the previous National Energy Board; and
2. the *Impact Assessment Act* established the new Impact Assessment Agency of Canada.

Bill C-69 also provides for changes to the Canadian *Navigable Waters Act* and to the *Fisheries Act*, to implement additional protection for waterways, fish, and fish habitat.

The federal government has stated that the overall intention of Bill C-69 is to implement better rules to foster "a modern environmental and regulatory system that protects the environment, supports reconciliation with indigenous peoples, attracts investment, and ensures that good projects go ahead in a timely way to create new jobs and economic opportunities for the middle class".

The Canadian Energy Regulator Act

The CER consists of a Commission of up to seven full-time commissioners. At least one full-time commissioner must be an Indigenous person. The Commission is responsible for the adjudicative functions of the CER, and it has exclusive jurisdiction to inquire into, hold hearings, and determine any matter within the jurisdiction of the CER.

The *Canadian Energy Regulator Act*, among other things, provides for the regulation of:

(a) pipelines, abandoned pipelines, and traffic, tolls and tariffs relating to the transmission of oil or gas through pipelines;
(b) international power lines and certain interprovincial power lines;
(c) renewable energy projects and power lines in Canada's offshore;
(d) access to lands; and
(e) the exportation of oil, gas and electricity and the interprovincial oil and gas trade.

The Impact Assessment Act

The *Impact Assessment Act* names the Impact Assessment Agency of Canada as the authority responsible for "impact assessments", which are defined to be assessments of the effects of a designated project that is conducted in accordance with the Act. *Effects* is defined broadly to mean, unless the context requires otherwise, changes to the environment or to health, social or economic conditions and the positive and negative consequences of these changes.

Among other things, the Impact Assessment Act:

(a) provides for a process for assessing the environmental, health, social and economic effects of designated projects with a view to preventing certain adverse effects and fostering sustainability;

(b) prohibits proponents, subject to certain conditions, from carrying out a designated project if the designated project is likely to cause certain environmental, health, social or economic effects, unless the Minister of the Environment or the federal cabinet determines that those effects are in the public interest, taking into account the impacts on the rights of the Indigenous peoples of Canada, all effects that may be caused by the carrying out of the project, the extent to which the project contributes to sustainability and other factors;

(c) establishes a planning phase for a possible impact assessment of a designated project, which includes requirements to cooperate with and consult certain persons and entities and requirements with respect to public participation;

(d) authorises the Minister of the Environment to refer an impact assessment of a designated project to a review panel if he or she considers it in the public interest to do so, and requires that an impact assessment be referred to a review panel if the designated project includes physical activities that are regulated under the Nuclear Safety and Control Act, the Canadian Energy Regulator Act, the Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act and the Canada–Newfoundland and Labrador Atlantic Accord Implementation Act;

(e) establishes time limits with respect to the planning phase, to impact assessments and to certain decisions, in order to ensure that impact assessments are conducted in a timely manner;

(f) provides for public participation and for funding to allow the public to participate in a meaningful manner;

(g) sets out the factors to be taken into account in conducting an impact assessment, including the impacts on the rights of the Indigenous peoples of Canada;

(h) provides for cooperation with certain jurisdictions, including Indigenous governing bodies, through the delegation of any part of an impact assessment, the joint establishment of a review panel or the substitution of another process for the impact assessment;

(i) provides for transparency in decision-making by requiring that the scientific and other information be taken into account in an impact assessment, as well as the reasons for decisions, be made available to the public through a registry that is accessible via the Internet;

(j) provides that the Minister may set conditions, including with respect to mitigation measures, that must be implemented by the proponent of a designated project;

(k) provides for the assessment of the cumulative effects of existing or future activities in a specific region through regional assessments, and of federal policies, plans and programs, and of issues that are relevant to the impact assessment of designated projects through strategic assessments; and

(l) sets out requirements for an assessment of environmental effects of non-designated projects that are on federal lands or that are to be carried on out outside Canada.

Other Federal developments

In November 2016, the Federal government announced a CAD$1.5 billion Ocean Protection Plan ("OPP") to improve marine life health and safety in response to tanker and fuel spills that have occurred in Canadian coastal waters, which included a five-year spending commitment commencing in 2017. The purpose of the OPP is to create a marine safety system, restore ocean ecosystems, develop new methods to clean up spills, and establish new legislation to hold owners responsible for the operation of their vessels.

In furtherance of the OPP, on May 12, 2017, the Federal government introduced legislation to implement the *Oil Tanker Moratorium Act* on British Columbia's north coast. This Act was proclaimed in force in June 2019.

The *Oil Tanker Moratorium Act* prohibits tankers from carrying more than 12,500 metric tonnes of crude oil or persistent oil products as cargo from stopping, loading or unloading at ports and marine installations from the northern tip of Vancouver Island to the Alaska border. The Act prohibits loading if it would result in the oil tanker carrying more than 12,500 metric tons of those oils as cargo. The Act also prohibits vessels and persons from transporting crude oil or persistent oil between oil tankers and those ports or marine installations for the purpose of aiding the oil tanker to circumvent the prohibitions on oil tankers. The legislation contains penalty provisions for contravention that could reach up to CAD$5 million.

Provincial developments

Ontario developments

The Province of Ontario elected a conservative government in June 2018, replacing a Liberal government that had governed the Province for the previous 15 years. During the election campaign, the Conservative Party heavily criticised the previous Liberal government for its decision to partially privatise the Province's electricity distribution company known as Hydro One, and also for high electricity prices. By some measures, Ontario's electricity prices had risen by 71% from 2008 to 2016, while during this period, the average growth in electricity prices across Canada was only 34%.

In 2017, the then Liberal government of Ontario passed legislation known as the Fair Hydro Plan which lowered electricity bills by 25% on average for all residential consumers in the Province. In the months leading up to the election, the then opposition Conservative Party criticised the Fair Hydro Plan on the basis that it did nothing to reduce the actual cost of generating electricity, but the Conservatives maintained that they would keep the Fair Hydro Plan.

Within a few weeks of being elected, the new Conservative government of Ontario passed several pieces of legislation or put in place new government policies for the stated purpose of implementing various campaign promises related to electricity issues. The new legislation and policies included:

1. The *Hydro One Accountability Act, 2018*, which placed constraints on compensation for the directors, Chief Executive Officer and executives of Hydro One (the operator of most of the provincial distribution grid), and provided that the distribution rates charged by Hydro One shall not reflect amounts paid for executive compensation.

2. The *White Pines Wind Project Termination Act, 2018*, which provides for the retroactive termination of the White Pines Wind Project and the decommissioning of the project. This was a wind generation project that had received final approval from the previous government during the election campaign. Under the legislation, the Project is to receive compensation for its reasonably incurred expenses in relation to the development, acquisition, leasing and construction costs, and decommissioning costs, but the Project is precluded from receiving payment of any additional damages beyond what is allowed in the legislation.
3. The *Cap and Trade Cancellation Act, 2018*, which effectively cancels Ontario's cap-and-trade program which the previous government had introduced to control carbon emissions. The current Ontario government has developed a new plan to address climate change, called A Made-in-Ontario Environment Plan, which is intended to address climate change by having clear environmental rules and strong enforcement of those rules.
4. Ontario's Ministry of Energy directed Ontario's Independent Electricity System Operator (IESO) to immediately wind down various electricity procurement contracts that the IESO had in place under a Feed-in Tariff (FIT) program, and a Large Renewable Procurement (LFP) program if the contracts had not yet received Notice to Proceed from the IESO, or if the contracts had not yet achieved certain key development milestones. The Minister of Energy stated that the FIT and LRP projects contributed to cost increases for electricity ratepayers and the projects were no longer needed to maintain the adequacy and reliability of Ontario's electricity supply.

Alberta developments

The Province of Alberta elected a new Conservative government in April 2019, replacing the New Democratic Party which had governed the Province for four years. The new Conservative government has promised that it will do everything it can to create conditions to allow the western Canadian oil and gas sector to thrive again after years of economic slowdown. Within the first few months of being elected, the new Alberta government passed several pieces of legislation which include:

1. The *Carbon Tax Repeal Act*, which repealed a tax on gasoline and fossil-fuelled home heating put in place by the previous administration. This tax was implemented as part of the previous administration's Climate Leadership Plan which sought to reduce emissions, diversify the economy and create jobs. However, the carbon tax imposed fiscal burdens on many businesses and individuals, making it more expensive to move goods and heat homes. Notwithstanding the repeal of the provincial carbon tax, the Federal government has implemented its own carbon tax scheme on provinces that do not legislate to Federal carbon tax benchmarks through the *Greenhouse Gas Pollution Pricing Act* (the "GGPPA").

   Where a province does not legislate carbon pricing standards that meet the Federal government's standards, the Federal government will impose its own mandatory carbon pricing scheme on such province. Although the Federal government has yet to impose the GGPPA in Alberta, the Conservative government in Alberta has vowed to oppose the GGPPA as unconstitutional.

   In May 2019, the Saskatchewan Court of Appeal issued a 3-2 majority decision that found that the Federal government does have the constitutional authority to implement a carbon tax through the GGPPA, and, similarly, in June 2019, the Ontario Court of Appeal issued a 4-1 majority decision that the GGPPA is constitutional. Both majority decisions found that the GGPPA is a valid exercise of the federal government's authority under the national concern branch of the Federal government's "Peace, Order and Good Government" power. Ontario and Saskatchewan have both appealed the respective decisions, and the Supreme Court of Canada will ultimately decide the constitutionality of the federal carbon tax in 2020.

2. The *Preserving Canada's Economic Prosperity Act* was proclaimed in force in Alberta in May, 2019. This legislation gives the government of Alberta the power to restrict the flow of energy products outside of the Province of Alberta, and many speculate that the legislation is directly aimed at increasing the price of gasoline in the Province of British Columbia in response to its opposition to the Trans Mountain Expansion Project. However, the Alberta government has yet to use the legislation to actually restrict the flow of energy products from Alberta.

Other judicial decisions and court judgments

In January 2019, the Supreme Court of Canada released its decision in *Orphan Well Association, et. al. v. Grant Thornton Limited, et. al*., a case commonly known as *Redwater*. The majority overturned the Alberta Court of Appeal's decision, and found that certain sections of the provincial *Oil and Gas Conservation Act* and *Pipeline Act* do not conflict with the priority scheme set out in the federal *Bankruptcy and Insolvency Act*. Accordingly, the Alberta Energy Regulator may prevent the abandonment or renunciation of an insolvent company's assets by a trustee and require the trustee to satisfy certain environmental claims in priority to the claims of secured creditors. Practically, this decision creates uncertainty for secured lenders to oil and gas producers, resulting in a chilling effect on financing in the oil and gas industry.

Major events or developments

A Canadian federal election is scheduled for October 21, 2019. The Liberal Party of Canada will attempt to retain the majority government that it won in the 2015 election. If the election results in a change of government, there could be significant changes to Canada's energy policies, including a possible repeal of the federal carbon tax.

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Chile

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Overview of the current energy mix, and the place in the market of different energy sources

The most important sources of primary energy consumed in Chile are oil (27%), coal (26%), firewood and biomass (23%). The most important sources of electricity generation are hydroelectricity (31%), coal (38%) and natural gas (15%). As of July 2019, non-conventional sources of energy accounted for 18% of the electricity produced in Chile, but with a high growth rate (57% of the new energy projects which have been declared under construction during 2018 are non-conventional renewable energy projects).

Most of the fossil fuel sources are imported (approximately 90%), while biomass is the main locally produced source of energy. Lithium and hydrocarbons found in liquid or gas state are not recognized as concessible under Chilean law and thus can only be domestically exploited either directly by the Chilean State or its companies, or by third parties who have been awarded administrative concessions or entered into contracts of special operations with the State (also known as *contratos especiales de operación* – "**CEOPs**"), subject to terms and conditions approved by the President of Chile by means of a supreme decree.

The main consumers of energy in Chile are the industrial and the mining sectors (40% jointly, 23% and 17% respectively), which are supplied with electricity (33%), diesel (26%) and biomass (29%). These sectors are followed by the transport sector (35% of final consumption) which is satisfied almost in its entirety with crude oil derivatives (although with an incipient increase of energy demands due to electromobility policies, especially in public transport), and the commercial, public and residential sectors which combined, account for 21% of the aggregate final consumption. Electricity supplies 22% of the aggregate final energy consumption in Chile.

<u>Oil</u>

As noted above, oil can only be exploited in Chile either by the State or a State-owned company, or by a third party that has either been awarded an administrative concession or has entered into a CEOP with the State. As of this date, Empresa Nacional del Petróleo ("**ENAP**"), a State-owned company, and GeoPark, a private company, are the main domestic producers of crude oil in Chile, and virtually all their oil extraction operations are conducted in the Magellanean Basin (both onshore and offshore). Domestic oil production, however, represents a very small fraction of the total amount of oil consumed in Chile; most of it is imported (97%).

Import, export, storage, refinement, transport, distribution, supply and commercialisation of oil or oil derivatives in Chile can be conducted by non-State parties. However, as per Decree with Force of Law No. 1 of 1978, any person conducting such activities has to be registered with and become subject to the overview of the Superintendence of Electricity and Fuel (the "**SEC**"), which monitors and oversees compliance with the laws, regulations and technical standards governing the generation, production, storage, transportation and distribution of liquid fuels, gas and electricity generally. Other than such registration, no concession or special authorisation is required to conduct any such activity.

As of today, ENAP is virtually the sole refiner of crude oil in Chile through its three refinery plants: the Biobío Refinery Plant (located near the city of Concepción in Region VIII); the *Concón* Refinery Plant (located near the city of Valparaíso in Region V); and the *Gregorio* Topping Refinery Plant (located in Region XII, near the domestic crude oil exploitation and extraction facilities).

As to storage, while ENAP has a significant market share, certain distribution companies of oil-related products such as Copec, Shell and Petrobras have their own storage facilities as well.

Gas

The gas market comprises: (i) pipelines connecting Chile and Argentina; (ii) domestic pipelines; and (iii) regasification terminals.

There are six natural gas pipelines that connect the local market with Argentina, with two located in the extreme south of Chile (*Gasoducto Posesión* and *Gasoducto Bandurria*); two located in central Chile (*GasAndes* and *Gas Pacifico*); and two located in Northern Chile (*GasAtacama* and *Norandino*).

There are three domestic pipelines, each built to reach specific markets: *Electrogas* (downstream of *GasAndres* and *GNL Quintero*), *Tal-Tal* (downstream of *GasAtacama*) and *Innergy* (downstream of *Gas Pacifico*). The major consumption centres also have local distribution networks. These include the networks of Metrogas (Santiago Metropolitan Region and Region VI), GasValpo (Region V), GasSur (Region VIII), Intergas (Region IX), Gasco Magallanes (Region XII) and Lipigas (Region II).

There are two liquefied natural gas ("**LNG**") regasification terminals in Chile: one located in Region V in the Quintero Bay (GNL Quintero); and the other located in Region II in the Mejillones Bay (GNL Mejillones).

The gas industry in Chile also includes "satellite regasification plants" which are local regasification plants that supply gas in areas which are not connected to pipelines. These plants are supplied by tanker trucks. Customers of these regasification plants include agriculture-related industries.

Most of Chile's gas distribution infrastructure was constructed during the 1990s, when Chile and Argentina executed bilateral agreements to regulate and promote the export of natural gas from Argentina to Chile. More than US$ 4.6 billion was invested in natural gas-related infrastructure. Significant investments were also made in natural gas distribution networks and in the conversion of domestic, commercial and industrial customers from other sources to natural gas.

In 2004, Argentinean natural gas curtailments began and became increasingly severe over the next few years until natural gas exports to Chile were halted in 2007, except for residential consumption – which continued, but at significantly higher prices due to the application of new Argentine export taxes. Natural gas imports from Argentina were resumed in late 2018, but with interruptible supply. In August 2019 the Argentinean Government approved natural gas exports to Chile for uninterruptible periods of eight months, between September 2019 and May 2020.

When the first natural gas supply restrictions from Argentina took effect, the Chilean government reacted by promoting the development of LNG terminals in order to restore gas supplies and enhance diversification and security of the country's energy matrix. This resulted in the construction of: (i) GNL Quintero, which started supplying gas in 2009, which was developed by ENAP, together with British Gas, Endesa Chile and Metrogas; and (ii) GNL Mejillones, which initiated operations in 2010, which was developed by Engie Energía Chile S.A. (formerly known as GDF Suez S.A.) and Corporación Nacional del Cobre de Chile (commonly known as Codelco, which is a State-owned mining company and the largest copper producer in the world). On August 6, 2019, Codelco sold its participation in GNL Mejillones to GNL Ameris SpA, a subsidiary of Ameris Capital Administradora General de Fondos.

As noted above, gas can only be exploited and extracted in Chile either by the State or a State-owned company, or by a third party that has either been awarded an administrative concession or has entered into a CEOP with the State. Distribution and transport of gas through pipelines, on the other hand, can be conducted directly by private entities, provided that they have obtained a permanent concession that allows its holder to: (i) build, maintain, and conduct distribution activities within a given geographical region; or (ii) provide gas transport services through a pipeline or integrated network, as applicable.

Chilean law allows the existence of overlapping distribution concessions within a given geographical region and for multiple transport concessions between the same begin- and end-nodes. Thus, the relevant authority cannot reject a concession request that complies with the relevant legal, technical, and economic requirements.

A transport concessionaire must operate under an open access policy, which is understood as the obligation of each transport company to offer its available capacity under the same economic, commercial, technical, and informational conditions to any individual demanding transport services.

Gas transport and distribution prices are freely set through bilateral negotiations between the parties involved, subject to a general maximum profitability limit up to 6% (Annual Cost of Capital) plus a 3% spread. Compliance with this limit is monitored annually by the National Commission of Energy (*Comisión Nacional de Energía* – "**CNE**"). The Annual Cost of Capital is calculated by the CNE every four years, considering the systemic risk of the activities of public gas distribution concessionaires in relation to the market, the risk-free rate of return, the market risk premium, and an individual risk factor per zone of concession.

The gas distribution industry market in Chile is also regulated and monitored by the SEC.

<u>Electricity</u>

In Chile, the main electricity system is the National Electric System (hereinafter, the "**SEN**"), which was created through the interconnection in November 2017 of the formerly known Central Interconnected System or SIC and the Northern Interconnected System or SING, which supplies electricity to over 97% of the national population, with a length of 3,100 kilometres. Additionally, there are a number of medium and small electricity systems in the regions of Los Lagos, Aysen and Magallanes and one small system on Easter Island, none of which have an aggregate capacity higher than 110 MW.

In the SEN, electricity generation is coordinated by a system operator, the National Electricity Coordinator (the "**Coordinator**"), whose main purpose is to minimise operational costs and to ensure the highest economic efficiency of the system, while meeting all service quality and reliability requirements established by law. Since Law 20,936, the Coordinator is also in charge of tracking and monitoring competition in the electricity industry and safeguarding open access to electricity transmission. The Coordinator also has a fundamental role in planning the expansion of transmission.

The electricity sector in Chile is divided into three segments: generation, transmission and distribution. In general terms, generation is subject to market competition, while transmission and distribution, given their natural monopoly character, are subject to price regulation. Final customers may be regulated or unregulated depending on their demand. Only unregulated customers may freely choose a provider and freely agree the energy price. Regulated customers are forced to contract with distribution companies and pay them a tariff defined by the Ministry of Energy.

The goal of the Chilean electricity legal and regulatory framework is to provide incentives to maximise efficiency and to provide a simplified regulatory scheme and tariff-setting process that limits the discretionary role of the government by establishing objective criteria for setting prices. The expected result is an economically efficient allocation of resources. The regulatory system is designed to provide a competitive rate of return on investment to stimulate private investment, while ensuring the availability of an electricity service to all who request it.

The generation segment consists of companies that produce electricity and sell their production to distribution companies, unregulated customers and other generation companies. The transmission segment consists of companies that transmit the electricity produced by generation companies at high voltage. The distribution segment includes electricity supply to final customers at a voltage no greater than 23 kV. In Chile, only generation and distribution companies may commercialise electricity.

Power generation companies satisfy their contractual sales requirements with dispatched electricity, whether produced by them or purchased from other generation companies in the spot market. The principal purpose of the Coordinator in operating the dispatch system is to ensure that only the most cost-efficient electricity is dispatched to customers. The Coordinator dispatches plants in the order of their respective variable cost of production, starting with the lowest-cost plants, such that electricity is supplied at the lowest available cost. Generators balance their contractual obligations with their dispatches by buying or selling electricity at the spot market price, which is calculated on an hourly basis by the Coordinator, based on the marginal cost of production of the most expensive kWh dispatched.

No concession or particular approval is required to engage in electricity generation (except for the development and operation of geothermal generation facilities, which do require a concession). All generators can commercialise energy through contracts with distribution companies for their regulated customers and unregulated customers, or directly with unregulated customers. All contracts executed between generation and distribution companies for the supply of regulated customers after 2005 must be the result of open, competitive and transparent auction processes. Generators may sell energy to other power generation companies on a spot price basis. Power generation companies may also engage in contracted sales among themselves at negotiated prices, outside the spot market. Contract terms are freely determined (except in the case of supply to regulated customers).

The Chilean electricity legal and regulatory framework does not require an electricity concession to build and operate transmission facilities. However, in case it is difficult to process and obtain rights to use or occupy third-party land affected by the transmission facility's layout, transmission companies may request and obtain electric concessions that grant the possibility of enforcing those easements in exchange for proper compensation to the owners of the affected land.

The transmission system is divided into the main following segments: (i) the National Transmission System, the high-voltage backbone of the whole system, which supplies energy to the entire electricity demand and permits connection with other transmission systems; (ii) the Zonal Transmission Systems, which supply energy to regulated customers; and (iii) the Dedicated Transmission Systems, through which unregulated customers receive energy and generators inject the energy produced into the grid.

(i) National and Zonal Transmission Systems are considered as a public service. They are subject to open access obligations and a regulated remuneration mechanism based on the amounts invested by the owner in building them and the costs incurred in their maintenance, which are determined by the Ministry of Energy and paid entirely by final customers (whether regulated or unregulated customers).

(ii) Dedicated Systems are also subject to open access obligations but limited to their corresponding technical capacity. With some exceptions, the Dedicated Systems' revenues come entirely from the tolling agreements freely agreed between the owner and the users (generation companies and unregulated customers).

Additionally, Law No 20,936 created two other transmission segments: (iii) the Development Zones Systems, destined for areas with resources or conditions of high potential for the production of electricity using a single transmission, which is of general public interest and economically efficient; and (iv) the International Systems, destined for exportation or importation of electricity.

Concessions are required to engage in electricity distribution. Concessions granted to distribution companies give them a monopoly in their respective concession area, according to which regulated customers are forced to contract with the respective concessionary company, paying a prefixed tariff. The distribution segment is also considered as a public service.

Final customers may be regulated if their connected power is equal or less than 5,000 kW, and unregulated if their connected power is higher than 5,000 kW. Regulated customers with a connected power higher than 500 kV, but less than 5,000 kW, have the option to move to the unregulated customers' price regime for a period of four years at least.

Finally, vertical integration in the electricity market is limited by a *prohibition* according to which companies that own or operate assets of the National Transmission System must not participate directly or indirectly in the power generation or power distribution business, and a *restriction* by virtue of which the individual participation of generation companies, distribution companies or unregulated customers must not exceed 8% of the initial value of the investment of the national transmission system, and the joint participation of generation companies, distribution companies and unregulated customers must not exceed 40% of the initial value of the investment of the national transmission system. The prohibition and restrictions are included in Article 7 of the General Electricity Act.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

During the last five years, the development of non-conventional renewable energies ("**NCRE**") has seen explosive growth. In 2014, the installed NCRE capacity registered

1,600 MW. As of July 2019, it was 5,000 MW. The explosive growth of NCRE projects, which in the past took place mostly in the north area of the country (nowadays there are also several projects in the central area), rendered the transmission facilities encompassed by the Northern Interconnected System insufficient to transport all the energy produced thereby, thus curtailments were necessary in order to avoid the system collapsing. Since most NCRE plants (especially solar plants) are located in the north of Chile and most final customers are located in the central or south areas (especially regulated customers), the difference of prices between the zone where such companies inject energy and the zone where they withdraw energy, generated concerns in the electricity sector. That problem has been mitigated by the interconnection between SING and SIC. Although the interconnection took place in late 2017, its practical effects have been felt since May 2019, following the commercial operation of Cardones-Polpaico transmission line (more on this below).

The general decrease of energy prices in the spot market has led many unregulated customers to re-negotiate their energy supply agreements, and many regulated customers who have the option to move from a regulated to an unregulated price regime, to do so. The number of regulated customers who moved to an unregulated price regimen increased by 163% between 2017 and 2018.

In order to mitigate uncertainty and the volatility of spot energy prices, many investors have invested in small power plants (no greater than 9 MW) connected to the grid through distribution facilities ("**PMGD**") or directly to transmission facilities ("**PMG**"), because the law recognizes to PMGD and PMG the possibility to be subject to a stabilised price regime of remuneration. In general terms, the stabilised price is calculated by the CNE using an average of the projected marginal cost of energy on a 24-hour base.

Notwithstanding the foregoing, the general decrease of energy prices has not had any effect for regulated customers, because they are subject to tariffs which are calculated by CNE and set by the Ministry of Energy based on long-term energy supply contracts, which have not yet captured the lower prices. Regulated customers will only start capturing those benefits in year 2021.

Developments in government policy/strategy/approach

In September 2015, with the participation of the government, several stakeholders, key participants in the energy sector, universities and the public at large, the Ministry of Energy produced and issued a document titled "Energy 2050", which contains Chile's long-term energy policy, defining what should be the Chilean energy matrix for the years 2035 and 2050 (the "**Energy Policy 2050**", which is available at http://www.energia2050.cl/en/energy-2050/energy-2050-chiles-energy-policy/).

The Energy Policy 2050 is based on four principles identified as: (i) quality and security of supply (i.e. reliability); (ii) energy as a driving force for development (i.e. inclusiveness and social sustainability); (iii) environmentally friendly energy (i.e. environmental protection and sustainability); and (iv) energy efficiency and energy education (i.e. competitiveness, efficiency and public awareness).

Within the framework of the Energy Policy 2050, the Ministry of Energy has developed a short-term energy policy known as "Energy Route 2018-2022: Leading the modernisation with a citizen seal" ("**Energy Route 2018-2022**", available at http://www.energia.gob.cl/rutaenergetica2018-2022.pdf), which contains the main ideas and projects to be conducted by the government that took office in March 2018. Two of the main goals of this short-term policy are: (i) to guarantee universal access to electricity services; and (ii) the decarbonisation of the Chilean energy matrix. To achieve such goals, the Government is promoting the following:

(i) modernise governmental authorities with jurisdiction over the energy industry;
(ii) collect information on energy access, to be able to focus resources where they are most needed (by creating a "map of vulnerability");
(iii) reduce processing time before the environmental authorities by 25%;
(iv) increase distributed generation capacity by four times the current capacity;
(v) increase by 10 times the number of electric vehicles in the country;
(vi) modernise electricity regulations, mainly for energy distribution;
(vii) regulate physical biofuels (such as firewood and its derivatives);
(viii) create incentives for energy efficiency in high-demand industries (mining, manufacturing, transportation);
(ix) create a program for the 'reconversion' of power plants that use coal as source; and
(x) train 6,000 people as operators, technicians and professionals in energy-related areas.

Developments in legislation or regulation

The following laws and regulations have been enacted during the last 12 months:

1. Law No 21,118 regarding residential generation. This law, which was published in the Official Gazette on November 17, 2018, is the latest amendment to the General Electricity Act. It seeks to incentivise residential generation by remunerating regulated customers that have co-generation or NCRE generation capacity not greater than 300 kW in their residences for the injection of their energy surplus to the distribution network.
2. Ancillary Services Regulation (*Reglamento de Servicios Complementarios*). Ancillary services are those that allow an adequate coordination of the SEN for its safe, economic and reliable operation, including frequency control services, tension control services and service recovery plans. This regulation, which was published in the Official Gazette on March 27, 2019, sets forth the procedures according to which ancillary services shall be remunerated and awarded through auctions.

Judicial decisions, court judgments, results of public enquiries

Power purchase agreements between generators and unregulated customers typically provide for arbitration in their dispute resolution clauses. Accordingly, the decisions and awards are subject to confidentiality. The Panel of Experts, in turn, resolves discrepancies in electricity and gas matters between the SEC, CNE, Coordinator and gas concessionaries or coordinated entities (such as generation companies, distribution companies, transmission companies and unregulated customers), which for the most part are of a very technical nature.

The main judicial or administrative decisions with an impact on the electricity market during the past 12 months are the following:

- *Normative recommendation procedure for the abrogation of the prohibition and restrictions set forth in Article 7 of the General Electricity Act on vertical integration requested by Celeo Redes Chile Limitada* (Antitrust Court of Chile, Index No ERN-24-2018). In February 2018, Celeo Redes Chile Limitada ("Celeo") a transmission company, requested the Antitrust Court (*Tribunal de Defensa de la Libre Competencia*) to exercise its power to recommend the abrogation of the prohibition and restrictions set forth in Article 7 of the General Electricity Act on vertical integration. The main argument made by Celeo was that those restrictions no longer made sense in light of current regulations and market structure. On December 26, 2018, the Antitrust Court rejected Celeo's request based on formal arguments, without making a decision on the merits of the prohibition and restrictions set forth in Article 7 of the General Electricity Act. In any event, during this process many governmental authorities (including the Ministry of Energy, the CNE and the Coordinator) and market participants provided their view as to the merits of Article 7, setting grounds for future debates.

- *Absolution of project fragmentation charges against the wind farm known as Cabo Leones raised by the Superintendence of the Environment* (Superintendence of the Environment, Index No D-1-2019; D-23-2019; and D-24-2019). In January 2019, the Superintendence of the Environment initiated an administrative procedure against Iberoeólica Cabo Leones I S.A., Iberoeólica Cabo Leones II S.A., Iberoeólica Cabo Leones SpA and Linea de Transmisión Cabo Leones S.A. for project fragmentation among a power plant of 321 MW and two transmission lines. Each project was approved after making separate submissions to the Environmental Assessment System ("**SEIA**") through an Environmental Impact Statement ("**DIA**") instead of being evaluated as only one project, which would have required an Environmental Impact Study ("**EIA**"), which has a longer and more complex approval process. In April 2019, after analysing the companies' arguments and reviewing all the information provided by them, the Superintendence of the Environment decided to conclude the investigation, stating there was intent to fragment the environmental approvals of the projects. The authority stated that the fact that different projects shared some common facilities (such as access roads, substations, connection points, etc.) was not enough to consider there was an artificial and illegal project fragmentation. In this case, the companies submitted separate DIAs due to legitimate technical, commercial and operational conditions.

Major events or developments

- In late 2018, the Ministry of Energy and the Ministry of the Environment initiated negotiations with generation companies with the purpose of implementing a decarbonisation process of the Chilean energy matrix. The goal of the Government is to progressively close all coal-fired thermoelectric power plants by 2040, which is the year when Chile expects to become a carbon-neutral country. In June 2019, the Government and the main generation companies entered into voluntary agreements by means of which the oldest eight thermoelectric plants (representing 1,047 MW of installed capacity) will stop their regular operations by year 2024.
- In May 2019 (after an 18-month delay), the 753 km transmission line called *Cardones-Polpaico* owned by Interchile S.A. started operating. The operation of this transmission line makes it possible to get the benefits of the interconnection of the SIC and the SING, by allowing transportation of the renewable and base-load energy that is generated in Northern Chile to the main centres of consumption. After only three months of operation, the *Cardones-Polpaico* transmission line has reached its full capacity during certain hours. There are plans for the construction of a new transmission line with a length of 1,500 km, connecting the *Kimal* substation (located in Antofagasta Region) and *Lo Aguirre* substation (located in the Metropolitan Region), although such project has not yet been included in any expansion plans, and may not start operating before year 2027.

Proposals for changes in laws or regulations

There are discussions of several amendments and new regulations related to the General Electricity Act, either in Congress or before the Ministry of Energy. The most important changes currently under discussion are the following:

1. Reducing profitability of energy distribution companies. A bill was sent to Congress in April seeking to reduce the profitability component considered in the tariff-setting process for electric distribution companies, which currently considers a 10% return over the investment before taxes. The bill follows a similar rationale as the one used for the reduction of the profitability component in energy transmission, given the political and economic stability that Chile has achieved. The bill considers that the tariff-setting process for energy distribution companies shall consider a market return within a 6% to 8% range after tax.
2. Amendments to the Decree No 244/2005 regarding PMG/PMGD. In April 2019, the Ministry of Energy announced changes to the stabilised price regime of remuneration applicable to PMGD/PMG. The main driver of the initiative was to replace the current stabilised price (which applies on a 24-hour basis and is calculated once every six months) by a price to be determined on the basis of six blocks of four hours each. During August 2019, the project was subject to public consultation and comments by interested parties. The issuance of a new regulation is expected within the upcoming months.

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He has been recently recognized as a next generation lawyer in M&A and Banking and Finance by *The Legal 500.*

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Overview of the current energy mix, and the place in the market of different energy sources

China is now going through a critical period of transition to the low-carbon energy society according to its 13th Five-Year Plan. From a general view, coal-based power generation still constitutes the main body of the energy market, along with a trend towards all-around development in oil and gas, as well as all kinds of renewable energy sources. Meanwhile, the adjustment of the energy production and consumption structure has entered into a dual-replacement period, during which oil and gas gradually replace coal, and non-fossil energy sources progressively substitute fossil energy sources. It is foreseeable that China's energy development trend in future decades will by symbolised by the features of: a low-carbon energy consumption structure; the intelligent production and consumption of energy; diversification of the energy supply; and the integration of multi-energy supply.

By the end of 2018, China had become the country with the world's largest installed capacity of hydropower, wind power and photovoltaic power. The installed capacity of renewable energy accounted for 38.3% of total installed capacity in China, a 1.7% growth on the previous year. The power generated from renewable energy accounted for 26.7% of the total power generation, of which hydropower accounted for 64%, wind power for 20%, photovoltaic power for 10% and biomass power for 5%.

As for coal-based electricity generation, which is still dominating China's energy sector, China is constantly promoting and adopting new technology to promote its all-around cleaner development. Various technologies for further reducing emissions and enhancing peak capacity are expected for coal-based power generation. It is estimated that by 2035, the proportion of the installed capacity of coal power will reduce to around 36%, and the proportion of coal-based power generation will reduce to about 50% of the total power generation.

During the energy transition period, an alternative approach for energy could be an engine for power production. Electric vehicles, clean heating, shore-to-ship power supply systems, and the upgrade of rural energy consumption will constitute the impetus for future growth of the power sector. It is predicted that by 2035, the proportion of electricity consumption will increase to about 35% of overall terminal energy consumption. Total electricity consumption will be about 12 trillion kWh, with *per capita* electricity consumption of about 8,500 kWh.

With the acceleration of energy transition and continuous maturing of the application of new technologies such as cloud computing, big data, IOT, smart city and mobile internet, the ideas of shared economy will expand to the field of energy and new industries, new business formats and new business models will constantly emerge. Moreover, the distribution network will become the basic platform for improving the general service level of power and serving the energy-sharing economy in the future.

Meanwhile, in order to adapt to the establishment of the energy-sharing economic system, China is exploring a revolutionary breakthrough in the power grid dispatching system, by utilising new technologies such as 5G network, big data, AI and blockchain, etc. – with the help of which, China will build up an intelligent dispatching system with the functions of high-performance interconnection, data sharing and human-computer interaction, etc.

At the transitional stage of China's power market, shifting from the planned type to competitive type, the government will still set up a feed-in tariff for some of the power generated. However, for the rest of the power generated, the electricity price will be marked to the market.

In all, clean energy is playing an increasingly important role in China's energy market. However, traditional energy consumption still accounts for a high proportion of China's total energy consumption. With the further implementation of the 13th Five-Year Plan for Energy Development, the transition of energy structure will remain an important topic for the development of China's energy market in the coming years.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy.

Hydrogen power will be further developed

In 2019, the pace of low-carbon energy transition is accelerating. In addition to wind power, photovoltaic power and hydropower, China is vigorously promoting the utilisation of hydrogen power.

During the 2019 Two Sessions, Tianlin Qian, a member of the CPPCC National Committee, proposed to support nuclear energy hydrogen production being included in the Major National Science and Technology Project. From his proposal, Mr. Qian illustrated the feasibility and advantage of producing hydrogen by the High Temperature Gas-cooled Reactor (HTCR).

In addition to the major breakthrough in hydrogen production technology, the government has also implemented several policies to support development in the hydrogen power sector. As viewed from a macro perspective, hydrogen power has been first mentioned in the Governmental Work Report. Furthermore, on March 5th, 2019, the National Development and Reform Commission (NDRC) and six other governmental departments, together issued the *2019 Catalogue for Guiding the Green Industry*, which contains several items mentioning hydrogen power and requiring the government to carry out policies and measures in relation to investment, price, financing and taxation. On April 8th, the NDRC, together with relevant governmental departments, issued the *Catalogue for Guiding the Adjustment for Industrial Structure* (2019 edition, draft for comments), covering contents in relation to high-efficiency hydrogen production, transportation and high-density hydrogen storage technologies, and the establishment of hydrogen power stations, etc.

In general, with the help of the breakthrough in technology in relation to hydrogen power production and the constant support of governmental policies, hydrogen power will play an increasingly important role in China's energy market in the coming years.

Developments in government policy/strategy/approach

Power grid parity policy for renewable energy

In 2019, the power grid parity policy for renewable energy has become a hot topic in China's energy market. With the introduction of this policy, China is ready to welcome a subsidy-free renewables era.

Within the year, the national energy authorities have promulgated a number of regulations and measures to carry out the power grid parity policy. With the constant introduction of these regulations and measures, the target guidance of China's renewable energy development, along with relevant mechanisms to guarantee energy consumption, construction management and the feed-in tariff, have been gradually improved. Moreover, the feed-in tariff of wind power and photovoltaic power has begun to transition from the stage of benchmark price to the parity and bidding stage.

Meanwhile, the market is playing a progressively important role in the allocation of resources. On May 20th, the NDRC and the National Energy Administration (NEA) announced the first batch of wind and photovoltaic power generation power grid parity projects in 2019, covering 16 provinces, with a total installed capacity of 20.76 million kWh.

Establishment of a long-term mechanism for renewable energy consumption

On May 10th, 2019, the NDRC and NEA announced the *Circular on Establishing and Improving the Mechanism for Guaranteeing the Consumption of Electricity from Renewable Energy Sources* (hereinafter the "Circular"), which clearly illustrated that the consumption subject's weight of responsibility should be allocated according to the provincial administrative region. Over the past decade, the speed of development of renewable energy in China has ranked first in the world. However, due to the inadequate peak-shaving capacity of the power grid system and the imperfect market mechanism, China's renewable energy development has been severely hampered. Several predominant problems include power limitation and power abandonment. Nevertheless, it is hoped the implementation of the Circular will alleviate these problems.

According to the provisions of the Circular, a market participant who fails to fulfil the consumption responsibility could make up for its failure through two alternative ways. One is to purchase the excess amount of power consumed by another market participant who would otherwise exceed its annual power consumption standard, with the price being solely determined by the two parties. The other way is to voluntarily subscribe for the renewable energy green power certificate (hereinafter the "green certificate"). If the market participant still cannot fulfil its consumption responsibility on time through these two ways, it will be jointly punished by relevant governmental departments, including being listed in the bad credit record.

Developments in legislation or regulation

Solar and wind power industry

On January 7th, 2019, the NDRC and NEA jointly issued the N*otification on Promoting Solar and Wind Power Tariff Without Subsidies*. In accordance with the Notification, China will carry out the feed-in tariff without a subsidies policy for solar and wind power, so that the electricity created by these sources can be sold at the same price as coal-fired power.

On May 28th, 2019, the *Notification on Matters Regarding the Construction of Wind and Solar Power Projects in 2019* was issued, in order to further lower the benchmark of the feed-in tariff for electricity generated by solar and wind power plant, and to set the pace and schedule for the application of this policy.

The primary cause of solar and wind-power being free of subsidies is the reduction in the levelised cost of energy (LCOE) along with technological development in wind and solar power generation, rather than the Chinese government's objection to the development of clean energy. With the further improvement of solar power technology, full-scale parity will be achieved gradually in the early stages of the 14th Five-Year Plan. In fact, some Chinese enterprises have started to promote the application of intelligent robots, which will actualise the automatic operation and maintenance of power stations and further lower costs in this era. Scientific and technological progress will inevitably reduce the cost of clean energy in the future development of China's energy market.

Subsidies for new wind and solar power generation projects are not all cancelled immediately after the issuance of the Notification. At present, the subsidy-free projects are mainly carried out in regions with superior resource conditions, and markets with guaranteed consumption. During the operation period, relevant policies will remain unchanged with regard to solar and wind power projects that have been approved and initiated before the end of 2020. New policies will be further discussed based on the feasibility and maturity of the technology, and will be implemented on projects approved and initiated after the end of 2020.

<u>Nuclear energy industry</u>

On July 23rd, 2018, the General Office of the State Council issued the *Guidance on Strengthening the Standardisation Work of Nuclear Power* (hereinafter referred to as "Guidance"). It puts forward five categories with a total of 11 key tasks, focusing on current prominent problems in respect to standardisation work on nuclear power projects, such as incomplete standards systems, unsatisfactory implementation and application, and insufficient international recognition and influence. The goal to enhance nuclear power standardisation in China is not only the result of the development of China's nuclear power technology, but also the demand of China's nuclear power "going global" policy.

After years of development, the major players in nuclear industries have basically formed their own national standard system, such as RCC, ASM, etc., and elevated the standard formulation to national-strategies level. As China makes giant strides in the nuclear power area, there is an inexorable trend to form its own, independent standard system. In accordance with the Guidance, the short-term target for China is to form an independent and unified nuclear power standard system by the end of 2019, which is in line with the progress level of domestic nuclear power industry. The medium-term target is to see a substantial growth in the extent to which China's nuclear projects adopt China's own domestic nuclear power standards and a marked boost in the international influence and recognition of China's nuclear power standards by 2022. The long-term goal is to stand in the forefront of the standardised nuclear power industry, and exert leadership over international nuclear power standardisation by 2027. In the meantime, China will actively participate in international nuclear power standardisation work.

<u>Oil and gas industry</u>

On June 30th, 2019, NDRC and the Ministry of Commerce issued the *Special Administrative Measures for Foreign Investment Access (Negative List)* (2019 edition). The 2019 Negative List will take effect on July 30th, 2019 and further liberalise market entry for foreign investment, with overall openness of China's oil-gas businesses. In the mining sector, restrictions on joint investment and cooperation in oil-gas exploration and development will be lifted.

This milestone event marks not only the breakdown of the monopoly pattern of the upstream oil-gas industry, but also the comprehensive openness of oil-gas exploration and development to foreign capital for the first time, and establishes the reform and opening-up of the whole industrial chain of China's Liquefied Petroleum Gas (LPG) industry from upstream, midstream to downstream as well.

The move could further boost China's oil-gas self-sufficiency. China has now become the world's largest importer of crude oil and natural gas. According to the *Development Report of Domestic and Foreign Oil-gas Industry* released by the Economic and Technological Research Institute of China National Petroleum Corporation (CNPC) in 2018, China's external dependence on oil and natural gas rose to 69.8% and 45.3% respectively this year. Therefore, it is urgent to increase the intensity of oil-gas exploration and development, enhance the capacity of oil-gas supply security, and build the oil-gas security guarantee system under comprehensive, open conditions.

The franchise of oil-gas exploration and development has long been enjoyed by large state-owned oil companies, such as PetroChina and Sinopec. Thereby, the market still fails to take a decisive part in oil-gas exploration and development, which leads to fewer market competitors and competitiveness, and results in low efficiency and high costs for oil development in the field. Nowadays, the restrictions of joint venture and cooperation in oil-gas exploration and development are being eased, and more market competitors are coming into this field. It is possible to increase China's oil-gas resource reserves as well as its self-sufficiency rate, and guarantee domestic supply, while improving the efficiency of oil-gas exploration and development.

The coal industry

On April 30, 2019, the National Development and Reform Commission (NDRC), Ministry of Industry and Information Technology (MIIT), NEA jointly issued the *Notification on the resolutions of overcapacity in key fields of 2019*. It requires a resolute withdrawal from those coal mines which fail to meet the requirements for safety and environmental protection, or coordinate advancement in ultra-low emissions, energy conservation and renovation of coal power plants, or promote efficient and high-quality development of clean coal power during the settlement of overcapacity in key fields in 2019.

On August 19, 2019, to implement the notification requirements, the NDRC, Ministry of Finance, Ministry of Natural Resources, Ministry of Ecological Environment, National Energy Administration and National Coal Mine Safety Administration jointly issued the *Plan for Classified Disposal of Coal Mines under 300,000 tons/year*. It is proposed to confine coal mines producing under 300,000 tons/year to 800 regions by the end of 2021, through arduous efforts and strict security measures such as environmental quality standards. Additionally, coal mines under 300,000 tons/year in North China and Northwest China (excluding the South Xinjiang), will be basically withdrawn, and the number of coal mines under 300,000 tons/year, will in principle be reduced in other regions by more than 50% at the end of 2018.

Judicial decisions, court judgments, results of public enquiries

Local court interprets the NDRC project approval authority in litigation

Case citation

Wang Ze etc., v. the National Energy Administration, Case No. (2018) Jing 01 Administrative First-instance 1267.

Summary of the case

The Development and Reform Commission of Shanghai (the SDRC) approved the construction project for Sanyuan 110 MW transformer substation on January 15th, 2018. On March 23rd, 2018, the NEA received an application for administrative reconsideration of the approval of SDRC, from 74 plaintiffs living around the transformer substation.

The NEA delayed the claim of the plaintiffs, saying there was no technical evidence to support their claims that the transformer substation would harm their health. The decision of SDRC was based on the Environmental Impact Assessment (EIA) of other authorities. There is no evidence that the EIA is mistaken, according to the NEA. If the plaintiffs have any doubt about the impact of the transformer substation on their health, they should turn to the environmental monitoring authority.

Dissatisfied with the NEA's Reconsideration Decision, the plaintiffs submitted the case to Beijing First Intermediate People's Court for judicial review on August 14th, 2018. The court held that the SDRC's decision was based on the Interim Measures for the Approval of Enterprise Investment Projects issued by the NDRC, and the Interim Measures only authorise SDRC to approve power projects in consideration of national economic development; SDRC is not required take impacts on a particular issue into consideration.

Comment on the case

The court supported the decision of the NEA in principle, although it reached the conclusion from another approach. The NEA's decision was based on the fact that the plaintiffs had no evidence that the transformer substation would have an impact on their health, while there was a valid EIA to support the project. The court decision was based on their interpretation of the NDRC Interim Measures. It is rare for a local court to interpret the regulations issued by central government.

<u>Supreme People's Court's attitude in environmental litigation</u>

Case citation

Friends of Nature Research Institute and China Environmental Protection Federation v. PetroChina and PetroChina Jilin Branch, Environmental Pollution Public Interest Litigation. Case No. (2018) Supreme Law Civil Retrial 177.

Case summary

PetroChina Jilin Branch caused serious environmental issues by discharging polluted air. In September 2016, the Friends of Nature Research Institute and China Environmental Protection Federation filed an environmental public interest lawsuit against PetroChina and PetroChina Jilin Branch for the discharge of atmospheric pollutants. PetroChina and PetroChina Jilin Branch believed that PetroChina Jilin Branch was the subject of independent litigation; PetroChina being co-defendants was without legal basis and contrary to legal principles.

Beijing First Intermediate People's Court, as the first-instance court, and Beijing Higher People's Court as the second-instance court, held that: PetroChina Jilin Branch has its own commercial licence and property and may be held responsible for its environmental liabilities. PetroChina shall not be listed as co-defendants. If the property of PetroChina Jilin Branch is not sufficient for compensation, PetroChina shall take joint liability.

Dissatisfied with the second-instance court decision, the Friends of Nature Research Institute and China Environmental Protection Federation submitted the case to the Supreme People's Court for retrial. The Supreme Court held that: the Civil Procedure Law allows a branch office to act an independent litigation subject; it doesn't exclude the possibility of listing the main body as co-defendants. In this particular case, PetroChina, as a centrally administered State-owned Enterprise and leading energy company in China, shall take its social liabilities promptly.

The energy sector faces many environmental problems. Listing PetroChina as a co-defendant could emphasise its obligations to supervise its branches in regard to their environmental obligations and produce a benefit for society. The denial of its co-defendant's qualification was wrong, and the decision of the second-instance court shall be dismissed.

Case comments

The Supreme Court decision not only interpreted the civil procedure law for listing co-defendants, it also emphasised the social impact of listing co-defendants in environmental cases in the energy sector. It implied that the Supreme Court intends to adopt strict environmental requirements in the energy sector.

Major events or developments

<u>Energy cooperation: China establishes the "Belt and Road Initiative" energy partnership with 17 countries</u>

On October 18th, 2018, as part of the "Belt and Road Initiative", meetings of energy ministers and the International Energy Revolution Forum were held in Suzhou city, Jiangsu province. China announced a *Ministerial Joint Declaration on Building The Belt and Road Initiative's Energy Partnership,* with 17 countries (Algeria, Azerbaijan, Afghanistan, Bolivia, Equatorial Guinea, Iraq, Kuwait, Laos, Malta, Myanmar, Nepal, Niger, Pakistan, Sudan, Tajikistan, Turkey, Venezuela), which agreed to establish the Belt and Road Initiative's energy partnership, and provide new models and mechanisms for promoting green and sustainable development of global energy.

Guided by the principles of extensive consultation, joint contribution and shared benefits, and with the purpose of boosting mutually beneficial cooperation, this partnership aims at helping all countries to resolve energy development problems, realise common development and prosperity, and contribute to the building of a community of shared future for mankind. In today's conditions of economic globalisation, world energy development represents a significant historical opportunity period of revolution, adjustment and cooperation. Energy cooperation through the Belt and Road Initiative can promote the connectivity of energy infrastructures, improve the capacity to optimise energy resource allocation, and open a vast overseas market for China's domestic energy enterprises.

<u>As the trade war between China and the United States heats up, Chinese photovoltaic enterprises demonstrate more resilience</u>

The trade war between China and the United States has been heating up during 2019. On May 9th, the United States announced that it would raise tariffs on Chinese imports worth $200 billion from 10% to 25%, from May 10th, 2019. Among those, solar cells, inverters, transformers and other photovoltaic products will be subject to a 25% tariff.

The so-called 201 case became the "fuse" for the Sino-U.S. photovoltaic trade war. On January 22nd, 2018, the Trump administration released 201 Resolution, concerning solar cells and components produced in China. It was to increase the tariff by 30% on photovoltaic cells and components on the basis of anti-dumping and anti-subsidy tax, which would also be followed by 5% decline annually over the next four years, with an exemption for 2.5GW of imported cells or components.

As a big exporter of photovoltaic products, China has been suffering frequent trade frictions with many countries apart from the United States, such as India and Turkey. However, trade frictions have encouraged many Chinese enterprises to increase the quality of their exports and export quantity growth year-on-year. For example, the European photovoltaic market is one of the "arenas" of Chinese photovoltaic enterprises this year. In addition, numerous Chinese enterprises also take advantage of the new opportunities of the Belt and Road Initiative countries to accelerate the upgrade of their energy structure.

Proposals for changes in laws or regulations

Oil and gas investment reform

1. *Transfer, circulation and exit mechanism of oil and gas mining rights*

   At present, the three top energy companies, PetroChina, Sinopec and CNOOC, have a share of the exploration rights in domestic oil and gas blocks of over 96%. Such a high concentration level of mineral rights is not conducive to other companies entering this area.

   It is urgent to issue supporting documents to regulate the operation rules for the transfer, circulation and withdrawal of oil and gas exploration rights and mining rights to ensure the smooth implementation of upstream reform and opening-up measures.

2. *Foreign investment in the oil and gas sector*

   Since the 1980s, foreign investment in China's oil and gas industry has been operated on a franchise system. Foreign companies could only develop inland or offshore oil and gas resources with specific Chinese companies, jointly based on the *Regulations on Foreign Cooperation in Exploitation of Inland Petroleum Resources*, or the *Regulations on Foreign Cooperation in Exploitation of Offshore Oil Resources*.

   Although the 2019 version of the negative list for foreign investment has clearly removed restrictions in the oil and gas sector, the path for foreign companies to obtain mining rights in the oil and gas sector is still not clear. Detailed regulations or guidelines for foreign companies to invest in the oil and gas sector are expected.

3. *Operation mechanism of oil and gas pipeline network*

   The *Measures for the Supervision of Oil and Gas Pipeline Network* provide principles for the operation of the pipe network. However, the operation of the oil and gas pipeline network and other oil and gas infrastructures in the future is a huge and complicated systematic project. As the reform continues, the laws and regulations and technical specifications are expected to be improved for operation.

Renewable Energy Consumption Guarantee Mechanism

Provincial system will be further improved

The *Notice on Establishing and Improving the Safeguard Mechanism for Renewable Energy Power Consumption* marks the arrival of the era of the "quota system" for renewable energy consumption. However, the "Notice" is only the beginning. Since the quota for each sector will be allocated by the provincial governments, further development of implementation plans shall be provided by provincial governments at the earliest opportunity.

Further performance supervision methods needed

The "Notice" clarifies that the competent department of energy of the State Council shall monitor and evaluate the performance of renewable energy power consumption in each province. The provincial-level energy administrative department is responsible for assessing the market entities that are responsible for the burden of consumption of renewable energy power. However, punishments for non-compliance with specific rectification methods are not clearly defined. Therefore, in order to ensure the effective implementation of the safeguard mechanism, the introduction of further performance-supervision measures is inevitable.

Expectation on cross-border energy cooperation legislation

Under the Belt and Road Initiative, energy cooperation between China and neighbouring countries has continued to grow rapidly.

In the field of oil and gas cooperation, the first-line project of Sino-Russian crude oil pipelines in the northeast has exceeded 100 million tons of oil supply to China. The second-line project of Sino-Russian crude oil pipelines was completed in November 2017. The Sino-Russian east-line natural gas pipeline construction has been smoothly executed and is expected to be completed at the end of 2019. In the northwest, the Central Asia-China natural gas pipelines A, B, C and Sino-Kazakhstan crude oil pipelines will be put into operation.

Cross-border power resources cooperation has developed rapidly. Yunnan Province has carried out extensive power resources cooperation with the bordering countries of Vietnam, Laos and Myanmar. So far, it has been interconnected with the Vietnam Power Grid through two transmission lines; it is interconnected with the local power grid in Myanmar through three transmission lines; and interconnected with the Lao National Grid through one transmission line.

China's cross-border energy cooperation with neighbouring countries has continued to grow, and cross-border pipeline construction and power grid construction have increased. However, there is currently no specific cross-border energy legislation. Oil, gas and power transmission are carried out in accordance with the general trade model, which cannot meet the current demand for cross-border energy cooperation.

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Finland

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Overview of the current energy mix, and the place in the market of different energy sources

According to figures compiled by Statistics Finland for 2018, the Finnish energy mix was as follows:

Total energy consumption by source (TJ) and CO_2 emission (Mt)

Energy source	2018*	Annual change %*	Percentage share of total energy consumption*
Oil	307 563	-2	22
Coal [1)]	112 121	-1	8
Natural gas	73 576	12	5
Nuclear energy [2)]	238 784	2	17
Net imports of electricity [3)]	71 769	-2	5
Hydro power [3)]	47 322	-10	3
Wind power [3)]	21 086	22	2
Peat	66 696	24	5
Wood fuels	376 338	4	27
Others	67 751	6	5
TOTAL ENERGY CONSUMPTION	1 383 005	2	100
Bunkers	46 019	7	.
CO_2 emissions from energy sector	41	3	.

* =*Preliminary*

1. *Coal: includes hard coal, coke, blast furnace gas and coke oven gas.*
2. *Conversion of electricity generation into fuel units: nuclear power: 10.91 TJ/GWh (33% total efficiency).*
3. *Conversion of electricity generation into fuel units: hydro power, wind power and net imports of electricity: 3.6 TJ/GWh (100%)*

According to Statistics Finland's overview, in 2018, the consumption of renewable energy sources increased by 3%, and their share of total energy consumption was 37%. The consumption of wood fuels increased by 4%, and they remained the most significant single source of energy in Finland, with a 27% share. The growth was due to the increase in by-products of the forest industry. The largest production increase concerned wind power, in respect of which production increased by as much as 22%. However, in relation to total energy consumption, the share of wind power is still small at only 2%. The production of hydro power decreased by 10%.

The use of fossil fuels and peat increased by 2% compared to 2017 and accounted for 40% of total energy consumption. The consumption of fossil fuels decreased by 8% with respect to coal and oil. However, with respect to natural gas, consumption increased by 12%, and with respect to peat, consumption increased by 24%, due to difficulties with acquiring wood fuels. Oil remained the second-most important individual energy source in Finland with a 22% share of total energy consumption.

The domestic production of electricity in 2018 was 67 TWh, which was 4% less than the previous year. Nuclear energy generated about one third of all electricity. Roughly the same amount of electricity was generated through combined heat and power production. The production of hydro power decreased due to poor water conditions. Wind energy production increased by 22%, and its share of electricity generation reached 9%. Solar power generation increased significantly, almost quadrupling during 2018. However, its share of electricity production reached only 2 *per mille* and due to the long, dark Finnish winters, it is still not anticipated that solar would make economic sense on an industrial scale.

The net import of electricity to Finland was 20.4 TWh, which corresponds to 23% of total electricity consumption. Compared to 2017, net imports of electricity decreased slightly; the share of electricity imported from Russia increased, and although the greatest amount of electricity came from Sweden, imports from Sweden fell slightly on the previous year. According to the Finnish energy regulator, in the Energy Authority's National Report to the European Commission for 2018, limited transfer capacity restricted the transmission of electricity from Sweden to Finland, which is why the wholesale electricity prices in Finland were different from the prices in Northern and Central Sweden for 27% of hours during 2017. In 2017, Finland and Estonia had same price for 98% of hours. In December 2016, Finnish and Swedish TSOs announced their agreement to build up a new AC-interconnector between the two countries by 2025.

End-use energy consumption increased by 2%. Consumption in the industrial sector increased by 4%, accounting for 48% of total end-use. Energy used for the heating of buildings remained at the same level as the previous year, corresponding to a 25% share of end-use energy. Energy used in transportation, with a 16% share, decreased by 1%.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Renewable energy subsidy scheme

On 25 June 2018, provisions on a new premium system based on a technology-neutral tender process were added to the Act on Subsidies for Electricity Produced from Renewable Energy Sources (1396/2010) (the "Act"). The entry into force of the new subsidy system was enacted through a ministerial decree.

The new support scheme comprises a competitive auction process. Whilst according to the

Act, the new subsidy scheme applies to wind power, solar power, wave power, biogas and wood fuel power, the only applicants to the auction were wind power projects. Hydro power was explicitly excluded from the support scheme.

The auction process was carried out during November and December 2018 in one bidding round, and the winners of the auction were announced in March 2019. Out of 26 bidders, seven bidders with the lowest offered premium were included in the premium scheme (as set out in the table below). The amount of support was determined for each bid separately (pay-as-bid). The average subsidy amount is 2.49€/MWh, with the lowest approved amount being 1.27€/MWh and the highest being 3.97€/MWh. The winners of the auction and the offered subsidy prices are as follows:

Company	Project (location)	Offer
Kestilän Kokkonevan Tuulivoima Oy	Kestilän Kokkonevan Tuulivoima (Kestilä)	1.27€/MWh
CPC Finland Oy	Lakiakangas 3 (Isojoki and Kristiinankaupunki)	1.89€/MWh
Puhuri Oy	Parhalahti (Pyhäjoki)	1.89€/MWh
Puhuri Oy	Hankilanneva (Haapavesi)	2.62€/MWh
Kalax Vindkraft Ab/Oy	Kalax (Närpiö)	2.87€/MWh
Tuuliwatti Oy	Tuuliwatti Simo Leipiö III (Simo)	2.94€/MWh
Tuulipuisto Oy	Hirvinevan Hirvineva-Liminka (Liminka)	3.97€/MWh

The winners will be paid the full subsidy amount, if the three-month average price for electricity is below the reference price (30€/MWh). If the price of electricity exceeds the combined amount of the reference price and the subsidy, the approved energy producers are not paid any amount. The amount of paid subsidy varies linearly, if the price of electricity is between the two.

The maximum duration of the support granted to the project is 12 years. The approval into the scheme is transferable to third parties in connection with the transfer of assets of the relevant project(s). The total annual production of the producers approved in the scheme will be 1.36 TWh if fully built out.

In line with other European markets, the relatively small capacity tendered under the premium scheme indicates that the legislative intention is that the Finnish wind industry should transition towards a market-based, subsidy-free sector, which must make sense without government support. It is therefore not anticipated that any replacement subsidy scheme will be implemented for Finnish renewable energy. This is also reflected by the increasing visibility of large-scale power purchase agreements (PPAs) in the Finnish energy market.

Infrastructure support

In Autumn 2019, the Energy Authority will arrange the second subsidy tender for the expansion of electric and biogas vehicle charging systems and refuelling stations, with the period for submission of applications running from 1–30 September 2019. The bidding will be arranged in four groups: gas filling stations; local public transport charging systems; high-power loading systems for vehicles; and basic vehicle charging systems.

The intention of the infrastructure support is to implement the national energy and climate strategy that goes beyond 2030. Support is granted to the extension of charging and gas discharge networks investments. Infrastructure support is distributed in three phases by bidding. The first bidding was arranged in 2018, and the third one will be probably arranged in 2020.

In the first bidding in 2018, support was granted to six gas filling station projects and two high-power loading systems. No bids were made regarding public transport charging systems or basic vehicle charging systems. All in all, only 51% of the total amount reserved for the bidding was distributed to the winners.

Developments in government policy/strategy/approach

The programme of the new government, formed after the election of the Finnish Parliament in April 2019, announced some ambitious intentions for acceleration of the transition to Finland becoming a clean energy market. Whilst generally being relatively light on the details as to how this will be achieved in practice, the programme did include the intention to draft a subsidy package for energy companies that abandon coal by 2025, which is much earlier than the deadline required in the Coal Ban Act (see the section, "Developments in legislation or regulation").

Furthermore, the government's intention is to end the use of oil in heat production by the beginning of 2030, and on State- and municipality-owned properties by 2024. A separate package will be drafted in order to encourage the transition from oil heating to other heating methods on properties during the 2020s.

Developments in legislation or regulation

Natural Gas Market Act

The Natural Gas Market Act (587/2017) was recently reformed based on the EU's natural gas regulation, providing for the opening-up of the Finnish wholesale and retail market for natural gas. Consequently, exceptions to the EU's internal market regulation in relation to the natural gas market will no longer be applied in Finland.

The new act entered into force on 1 January 2018. However, provisions regarding the liberalisation of the natural gas market will enter into force in 2020. In Finland, Gasum Oy has the monopoly in the natural gas importing, transfer and wholesale market. The new legislation requires that the company's functions be separated by incorporating new companies in respect of different business divisions.

The intention is to schedule the reform so that it will be enforced simultaneously with the launch of the Baltic Connector pipeline connecting the Finnish and Baltic natural gas networks. Currently, Finnish natural gas is mostly imported from Russia, and LNG is imported into Finland by ship. The Balticconnector pipeline will enable direct access to the natural gas markets of Estonia, Latvia and Lithuania, creating new opportunities for natural gas users and investors.

Coal ban

The Act on Prohibiting the use of Coal in Energy Production entered into force on 1 April 2019. According to Section 5 of the Act, the use of coal as a source for electricity and heat production will be prohibited as of 1 May 2029. The act will naturally have a very significant impact on generation facilities, as well as promote the growth of electricity renewable energy sources. Furthermore, the government's intention is to draft a subsidy package for energy companies that abandon coal by 2025.

The aim of the act is to ensure that the use of coal in energy production will end before 2030, while at the same time promoting indirectly the low-carbon energy system and the use of renewable energy sources. In addition, the aim is to ensure that such power plant or heating investments or replacement investments, which rely on coal energy, are no longer viable. In addition, the aim is to ensure that the provision of security for energy production, security of supply and exceptional situations, are maintained in a cost-effective way.

Emissions trading

An amendment to the Emissions Trading Directive took effect on April 2018. The amendment mainly concerns changes to the emissions trading scheme for the next trading period starting in 2021. In Finland, the required amendments to the Emissions Trading Act 311/2011 entered into force on 19 March 2019. In addition to the implementation of the Directive, the legislative amendment brought improvements that have been found necessary at a national level on the basis of the current trading period.

New Act on the reduction of the life-cycle gas emissions from certain fuels

The Act on the reduction of life-cycle greenhouse gas emissions from certain fuels came into force in March 2018. The Act transposes Article 7a of the Fuel Quality Directive, the FQD, into national law.

The Act provides for the reduction of greenhouse gas emissions from transport fuels. The Act applies to fuels used in motorised vehicles, mobile work vehicles, agricultural and forestry tractors and inland waterway vessels and recreational craft. The law applies to suppliers of the aforementioned fuels that supply more than one million litres of liquid fuels per calendar year or a corresponding amount of gaseous fuels with an energy content.

The Act legislates for the reduction of fuel greenhouse gas emissions from fuels by 2020. According to the obligation, fuel suppliers will have to reduce lifecycle greenhouse gas emissions of their fuels released by consumption, by 6% by the end of 2020 compared to 2010 emissions.

According to the Act, fuel suppliers must report to the Energy Authority on the fuel information they have released for consumption per calendar year.

Judicial decisions, court judgments, results of public enquiries

KHO:2019:72

A local environmental protection organisation had demanded that peat production carried out by the company A Oy be discontinued in four production areas. Adequate permits had been granted for the project earlier, but the water structures of the production facility functioned more poorly than expected. Also, the conditions of waters underneath the peat production facilities had deteriorated. The Supreme Administrative Court considered that there were no grounds for discontinuing production, since it could not be proven that the deterioration of waters was caused by the company. There was also no proof of the company having breached any permit provisions.

KHO:2019:55

The case concerned Fennovoima Oy's Hanhikivi I nuclear power plant project. The project required multiple permits regarding e.g. construction, environment, water, chemicals and nuclear production. During the appeal process concerning the project's environmental and water permits, the adequacy of the environmental impact assessment (EIA) process was examined. As a general rule, an EIA must be taken into account in every permit process. The EIA report described the functions and assessed the environmental impacts of the power plant. Matters related to final disposal were to be conducted in a separate EIA process later on. The Supreme Administrative Court considered that the EIA process was not inadequate in relation to environmental and water permits, since matters related to final disposal were presented with sufficient accuracy in relation to the aforementioned permits. The fact that more detailed information regarding environmental impacts were presented in other permit processes at later stages did not prove the insufficiency of the EIA process.

Major events or developments

The main market development has been the move in wind power towards a market driven largely by private PPAs, currently the hottest topic in the Finnish energy sector.

The first sign of this new development was detectable in May 2018, when TuuliWatti announced the first Finnish 'market-based' wind power project. TuuliWatti's project will consist of five Vestas V150 turbines with a power output of 4.2 MW and a tower height of 175 metres, with a sweep height of 250 metres, which are set to be the highest turbines in the Nordic countries when constructed. According to TuuliWatti's press release, as the V150 is up to twice as high as previous turbines, the production cost of electricity will remain below €30/MWh. This project will reach COD in 2019 and while it is set to receive Government subsidies, the Government support will be very marginal, and it will serve mainly as backup funding for the project.

Of potentially greater significance, however, is Google's announcement in September 2018 that it has signed three Finnish PPAs to acquire the whole production of three soon-to-be built wind farms for a duration of 10 years. The collective addition to Finnish electric capacity from wind power will be 190 megawatts (MW), which is a sizeable addition for Finnish wind power, as the total capacity constructed during 2017 was 516 megawatts (MW). The windfarm operators that have signed PPAs with Google are long-standing European players: French Neoen; German-based CPC Finland; and Wpd Finland.

There are a number of ongoing PPA processes which are expected to result in further significant PPA announcements during 2019.

Emissions from the Finnish Emissions Trading sector increased by 1.1 million tonnes in 2018. The total emissions of Finnish power plants belonging to the EU emissions trading scheme were 26.2 million tonnes of carbon dioxide in 2018. In 2017, the corresponding emissions were 25.1 million tonnes. The main reason for the increase was the increased use of peat and natural gas.

The Baltic Connector's completion by the end of 2019 is designed to connect the Finnish gas market to the Baltic States and allow Finnish gas operators to buy gas from the joint Finnish-Baltic market, also creating an expanded market for the Baltic States.

According to the 2018 National Report, the most significant generation investment project in Finland is the construction of nuclear power plant unit Olkiluoto 3. The completion of the building of this 1,600 MW unit has been delayed for a decade. Originally, the new unit should have been commissioned by the end of 2009. According to estimates announced in 2018, the reactor was supposed to be in operation in Autumn 2020. However, according to the announcement made in June 2019, the construction has been delayed once again. A new schedule for the operation is yet to be announced.

In addition, Fennovoima is currently developing a nuclear power plant with planned capacity of 3,220 MW of thermal power and about 1,200 MW of electrical power. The plant will be built in Pyhäjoki in Northern Finland and, according to the currently agreed schedule, Hanhikivi 1 plant will enter commercial operation in 2028, although this is an amended schedule based on project delays. The project has received a decision-in-principle from the Finnish Government and the Parliament and awaits a construction permit, which is expected to be granted in 2019.

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Overview of the current energy mix, and the place in the market of different energy sources:

France's primary energy mix is rather diverse nowadays. Even though it mainly relies on nuclear fission and fossil fuels – uranium, oil, coal and natural gas being widely, if not exclusively, imported – the country has opened up to renewable energies for an increasing share over the past decade.

For a long time, France has indeed focused its energy policy on developing nuclear power plants which are notably known for emitting very few greenhouse gases (GHG) but also raising burning issues regarding waste, site rehabilitation and safety measures.

However, France has now engaged a major energy transition, taking advantage of a significant supply of energy from renewable sources all over its territories, on the mainland as well as overseas. Therefore, among European countries, France enjoys the second-largest wind power potential and ranks at fourth place in terms of solar energy production. In addition, given their level of technological maturity, price competitiveness and the existing legal framework for wind and solar, both sources are very promising in the near future.

In 2015, the law n°2015-992 related to energetic transition for green growth (LTECV) was enacted and now constitutes the pillar of France's policy in terms of GHG emissions and renewable energies for 2050. It aims to reduce GHG emissions by 40% in 2030 and to divide them by four in 2050 compared to 1990; to reduce primary energetic consumption of fossil fuels by 30% in 2030 compared to 2012; to cut the share of nuclear energy to 50% of electricity production by 2025; and to reach 32% of renewable energies in final consumption by 2030.

From a legal point of view, France's energy law is ruled under both European Union law and national law.

The hereabove aims to change the part of each energy in the overall energy mix to comply with national targets laid down by the EU. The Directive 2009/28/EC on the promotion of the use of energy from renewable sources, commonly referred to as the Renewable Energy Directive, set a target of 23% share of energy from renewable sources in gross final consumption of energy in 2020 for France. To comply with the obligation set in the Renewable Energy Directive, France has drafted and submitted to the European Commission its National Renewable Action Plans, explaining measures and national policies which will allow these targets to be met.

In terms of statistics, the 2018 French Energy Report published by the government shows that France's primary energy mix was composed of nuclear energy (41.1%), oil (28.6%), gas (14.8%), renewable energies (11.4%), coal (3.7%), and non-renewable wastes (0.6%).

Concerning only electricity production, the main sources are: nuclear energy (70%) and renewable energies (20%) – among which hydroelectricity stands as the first renewable source; followed by thermic fossil combustion, eolian and solar.

Table 1 – French electricity mix

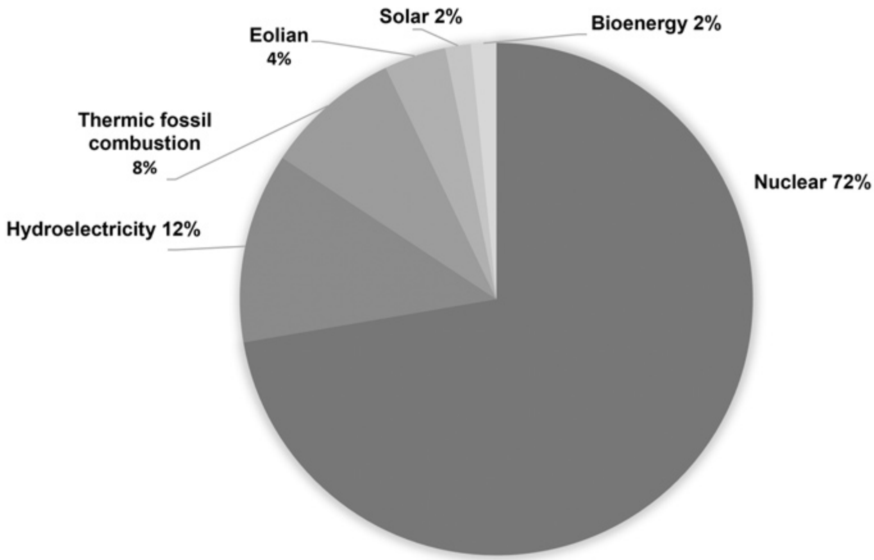
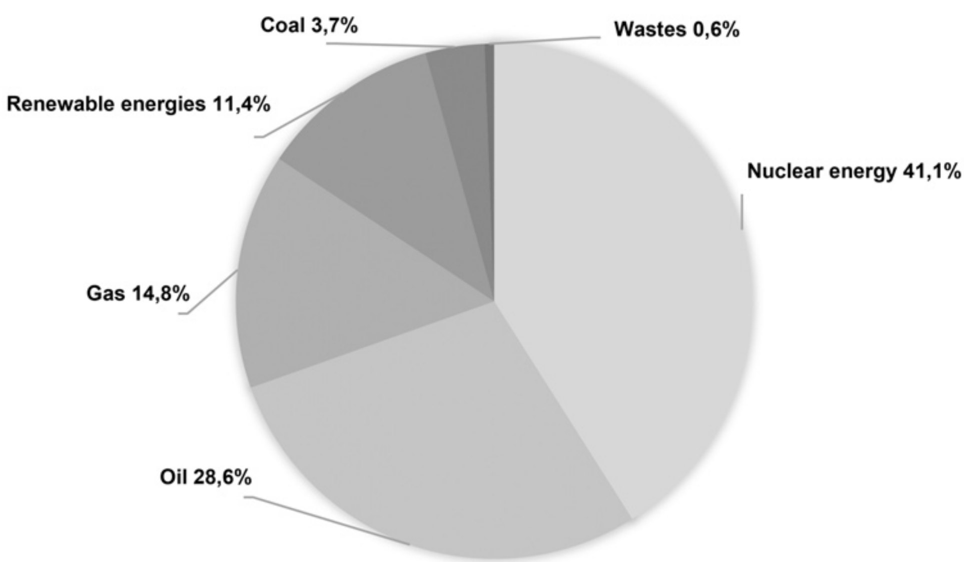


Table 2 – French energy mix



(Source: Ministry of Ecology)

In 2018, renewable energies made up 16.5% of France's final energy consumption, thus falling below the initial 20.5% intermediate target. As of December 31, the wind and solar sectors contributed up to 98% to the growth of renewables on a one-year rolling basis. The power of wind and solar farms reached 23.6 GW, while the hydraulic sector remained stable with 25.5 GW installed in France, while generation from bioenergy amounted to 2 GW.

According to the 2018 *Panorama of Renewable Power in France*, published by RTE (French TSO), SER (French Renewable energy trade association), Enedis (French DSO), the Agence ORE (Energy Network Operators Agency) and ADEeF (Association of the Distributors of Electricity in France), the growth of the renewable energy generation fleet reached 2.5 GW over one year, bringing its capacity to 51.2 GW.

France's energy consumption – which is almost twice as high as its domestic energy production – is mainly due to three sectors: transport, buildings and industry.

Regarding transport, such consumption stems from the overwhelming weight of merchandise transported by road rather than by train. The government, through several tools, aims at developing electric or hybrid vehicles to 2.9 million by 2023, and deploying 7 million recharge points by 2030. As for buildings, the government intends to boost renovation programs as well as the construction of high-performing buildings to contain the energy consumption.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

France's energy situation has been influenced in the past year by at least three changes related to: (i) political events; (ii) new discoveries of resources; and (iii) availability of imported resources.

First, France has faced at least three major political events related to its energy transition.

Fessenheim and Flamanville nuclear centrals – In order to achieve its 50% target by 2035, the government is planning on closing France's oldest nuclear centrals, among them the plant in Fessenheim. Such project follows a presidential campaign promise made in 2012, arising heated debates as a wide range of social, economic and political interests are at stake, and being pushed back several times. The Flamanville European pressurised reactor (EPR), a €10 billion nuclear project managed by EDF and using modern technology, was indeed seen as an alternative to the Fessenheim central. However, EDF has encountered many difficulties during its realisation, so that the closing of Fessenheim depends on completion of the EPR, which might not happen before 2020, if not delayed again in-between. The closing process will include €400 million compensation from the State to EDF, and a €30 million subsidy to local municipalities over the next 10 years. Several calls for tenders designed for the site's rehabilitation are likely to be issued as well.

Civil society engagement – Following the Yellow Vests movement and its populist protests, the government launched the "Great National Debate", a nationwide public consultation on four sensitive issues, including ecological transition. The results indicated a reluctance to pay environmental taxation and interest in financial support – although existing mechanisms designed to promote energy efficiency remain mostly unknown to the public. Recent demonstrations from French youth in Paris also had an impact on the government's energy initiatives.

Climate litigation – Over the past few months, a growing number of legal actions have been engaged by NGOs and local politicians to engage the State's environmental liability. These actions echo the recent Dutch *Urgenda* case law in October 2018 which recognized, under the European convention on Human Rights, the Netherlands' duty of care and an obligation to raise its targets in terms of GHG reduction.

On November 20th, 2018, one mayor engaged an informal appeal against the Minister of Ecology for his inactions on climate change, seeking to compel the government to respect its international environmental engagements and to lay down more ambitious ecological transition targets. The case was brought to the *Conseil d'Etat* in January 2019 and is ongoing. Moreover, in March 2019, four NGOs engaged the State's liability through a legal action labelled as "The case of the Century" in the public sphere, and notably grounded on the European convention on Human Rights, the French Constitution, and France's low-carbon strategy. It aims at recognizing that France has a general climate obligation, and that the lack of sufficient ecological measures thus constitutes a breach of duty, justifying compensation for the resulting moral and ecological prejudices.

Although the outcome of these proceedings is still uncertain, they seem to foreshadow a judicialisation of environmental activism which could impact the energy sector – directly or indirectly.

Second, in line with its aim to achieve the energy transition by 2050, France is making efforts to develop alternative sources of energy and to determine which are the potential energy development fields. A report by the ADEME, published in 2017, identified a theoretical maximum potential amount of renewable electric energies on available surfaces compatible with the actual regulation of more than 1,500 TWh/year, that is to say thrice the level of France's current electricity demand. For instance, in April 2019, another report by the ADEME assessed that potential photovoltaic fields on abandoned industrial sites and parking areas constituted an amount of power up to 53GWc. Moreover, offshore wind turbines electricity constitutes a promising resource as well: with the second-largest marine territory in the world, and the second largest coast in Europe, France's total installed capacity for this resource could reach 60GW. Finally, France also focuses on hydrogen; green gas is thought to represent 300TWh of potential production by 2050.

Third, it could also be noted that France's energy independence rose by 2.6 points, to reach 55.4% in 2018, according to the Ministry of Ecology's General Commissioner on Sustainable Development (CGEDD). Almost half of its oil imports still come from OPEC countries, while imports from Iran drastically decreased due to the economic sanctions imposed on the country.

Developments in government policy/strategy/approach

Since the early 2000s, France has adopted a series of laws aimed at setting detailed targets to achieve the energy transition. French lawmakers have multiplied bills, conventions and roadmaps on this matter, forming a complex set of intertwined legal documents. Several independent panels of experts have pointed to the resulting lack of visibility of France's energy strategy, as well as the fact that most of these documents are not legally binding.

The French energy policy is grounded on two pillars, introduced by the 2015 energy transition for green growth Act (LTECV law): the low-carbon national strategy (*Stratégie nationale bas carbone* – SNBC); and the multiannual energy program (*programmation pluriannuelle de l'énergie* – PPE).

Low-carbon strategy (SNBC) – The SNBC defines cross-cutting and sectoral objectives to conduct France's policy in terms of GHG emissions in the long-medium run. This non-binding document has set "carbon budgets", i.e. national emissions thresholds on five-year terms, broken down into sectoral activities. Civil society was involved in the elaboration of the SNBC, as well as the National Council for Ecological Transition (CNTE).

Carbon budgets are set for five-year terms. The 2015 SNBC defined the first three carbon budgets for 2015–2018 (442 $MtCO_2e$/year), 2019–2023 (399 $MtCO_2e$/year) and 2024–2028 (358 $MtCO_2e$/year).

The SNBC2 project was published in December 2018 and is still being examined by the government. One of its main objectives is to reach carbon neutrality by 2050. It should also raise the 2019–2023 carbon budget to 421$MtCO_2e$ and present the fourth budget for 2029–2033, which should be set at 299$MtCO_2e$.

Multiannual Energy Program (PPE) – The PPE establishes the priorities in terms of energy policy for public actors to reach the objectives set by the LTECV and has a significant impact on the national energy strategy. Legally binding, the published report will be annexed to a decree defining the main energy objectives and action priorities. Thus, strategies and planning documents that include energy guidance, such as regional climate, air quality and energy plans, must be consistent with the guidelines set out in the PPE. In that respect, the PPE set quantitative targets for the launch of tenders for renewable energy projects, for load management capacities or for investments enabling the injection of biomethane into gas networks.

The first PPE, adopted on October 28, 2016, covers the 2016–2018 term (imperative recommendations) and the 2019–2023 term (indicative recommendations).

The second PPE project, announced in November 2018, published on January 25, 2019, covers two successive five-year periods: 2019–2023 and 2024–2028. The project is currently under formal consultation phase, as opinions are being requested from entities such as the environmental authority, the National Council for Ecological Transition, the Public Electricity Distribution System Committee, and bordering or non-bordering countries whose electricity system is interconnected with the French one.

The PPE focuses on setting a fair carbon price, reducing emissions from buildings in the residential and tertiary sectors, and promoting green mobility, fostering the implementation of Energy Efficiency Certificates (*Certificats d'économie d'énergie* – CEE). It also aims at shutting down the last coal plants by 2022 and 14 out of the 58 existing nuclear reactors by 2035.

As for renewable energies, the PPE sets ambitious targets for each source: the tripling of onshore wind energy (24.6 GW of installed power by 2023) and a fivefold increase in photovoltaic energy (20.6 GW of installed power by 2023). The Draft Decree also set an indicative timeframe for the launch of calls for tenders for renewable energy plants.

Both frameworks outline France's roadmap toward a substantial GHG emissions reduction by 2050, but may also face difficulties in being implemented and abided by.

Developments in legislation or regulation

As a member state of the European Union, France must comply with the EU legislation, such as the **Clean Energy Package**, adopted on November 30, 2016 by the European Commission. This Package is a set of seven texts (four directives, three regulations) regarding the EU's energy security, energy market, energy efficiency, decarbonation, research, innovation and competitivity. Those texts were adopted successively in May 2018, December 2018 and June 2019.

Among these texts, Regulation (EU) 2018/1999, published on December 11, 2018, set the general framework for European energy governance. In the same fashion as the Paris Agreement's Nationally Determined Contributions (NDCs), each State must publish an integrated national plan on energy and climate for 2021–2030. The first one must be notified to the Commission on December 31, 2019 at the latest. Then, every ten years, each Member State will have to communicate its long-term strategy; 30 on years at least.

The Directive n°2018/2001/EU focuses on renewable energy. It sets a target of at least 32% of renewable energy in the EU around 2030. It also plans to simplify administrative procedures, harmonise the legal regime of State aids, guarantee the access of clean energy to distribution grids, and foster green fuels through the installation of charging stations.

At a national scale, France must now implement this Package through national laws. As stated above, France enacted its LTECV law on August 2015 and this act, along with the PPE, is the current pillar of France's legislation in terms of GHG emissions and renewable energies for 2050. The LTECV law also aimed at simplifying the administrative procedures needed to operate projects that could be related to energy.

In 2017, following enactment of the LTECV law, an ordinance generalised the "environmental authorisation", a permit consolidating the necessary authorisations for a project in one single document applied for through a single process. This "environmental authorisation" is applicable to wind farms, methanisation units and some solar projects that fall within the scope of the classified installations for the protection of environment (ICPE), or the law on water (IOTA) regulations. Such measure is meant to provide more legal certainty to these projects by limiting the number of possible legal actions from opponents.

Plus, the LTECV law encouraged municipalities to invest in certain firms producing renewable energies, and those firms can also offer a share of their capital to local residents and public entities.

In 2018, several laws and decrees were adopted to accelerate the construction and operation of renewable energy projects. This has been done mainly by trying to limit potential legal proceedings, as litigations sometimes slow those projects down for several years. In this context, the 2018–1021 act on the evolution of housing and urban planning ("ELAN" Act) imposed stricter conditions to engage litigation against a project, and more severe sanctions in case of abusive actions.

The "ESSOC" Act, published on August 10, 2018, suppressed a degree of jurisdiction for litigations against onshore eolian projects. Such proceedings must now be taken directly to an administrative Court of appeal, and the ruling can thus only be contested in front of the *Conseil d'Etat*. Decree n°2016-9, published on January 8, 2016 also attributed exclusive competence to the Nantes Administrative Court of Appeal over offshore eolian litigations, meaning no appeal will be possible in those cases.

Renewable energy communities, citizens energy communities and collective self-consumption – One major innovation of the Clean Energy Package consisted in the creation of two new regimes: "renewable energy communities" (Directive 2018/2001, December 11, 2018); and "citizens energy communities" (Directive 2019/944, June 5, 2019). Although the definitions must be transposed into national legislation and are thus not definitive, the Clean Energy Package provides general guidelines to Member States: participation in those communities must be free and non-discriminatory, and the project must not be guided solely by profit. Renewable energy communities are limited to production/consumption/stockage/sale of renewable energies, while citizens energy communities can provide other services such as recharge, energy efficiency, etc. Support measures will be put in place to foster their development, but the form of those aids is not settled yet: they could include financial support (buying obligation, call for tender), fiscal support (tax exoneration), and information support (creation of informative administrative offices).

Renewable energy communities will certainly be used as a tool to develop **collective self-consumption projects**. In France, the act for the growth and transformation of companies ("PACTE" act), published on May 22, 2019, brought some changes to the regime of collective self-consumption projects. The act introduced an experiment until May 23, 2024, by which date consumers will not have to be located upstream to the medium-low electricity transformation post any more. They will now be located on the low-tension grid on the basis of geographic proximity criteria. This mechanism should enable consumers to maximise self-supplied electricity consumption, multiplying potential consumption time slots and better suiting the needs of self-consumption installations.

Judicial decisions, court judgments, results of public enquiries

Authorisation of offshore wind projects – Over the summer of 2019, the *Conseil d'Etat* sought to accelerate the finalisation of a set of offshore wind farm projects selected following calls for tenders in 2012 and 2014. Several projects were indeed slowed down by legal actions from competing firms and environment associations. Five projects were thus launched following three rulings on June 7th, July 24th and August 21st.

Environmental authority – One particularly sensitive issue in France for the building of energy power plant is that of the environmental authority (*autorité environnementale*). A directive of the EU (December 13, 2011) imposes, for every project that can potentially impact the environment, an authorisation process evaluating those potential impacts. In its *Seaport* ruling (C-474/10, 20th October 2011), the Court of Justice of the European Union ruled that Member States had to ensure a functional separation between the authority in charge of the authorisation, and the authority in charge of assessing the environmental impact of the project.

Two rulings of the *Conseil d'Etat* – n°400559, December 6, 2017 and n°414930, March 13, 2019 – cancelled France's regulation designating the prefect of the region as the environmental authority. The *Conseil d'Etat* judged that those dispositions did not ensure an effective functional separation because: (1) region prefects can also be department prefects, and therefore the same person could give the authorisation *and* an opinion on the project; and (2) in most cases, the administrative services in charge of preparing the assessment were under the authority of the entity competent for the authorisation.

The government has not yet corrected those decrees, creating a loophole and legal insecurity for projects that were authorised while the decree was still in place. Administrative courts thus conduct a case-by-case analysis of all the projects authorised on the ground of the illegal regulation, sometimes leading to contradictory decisions between jurisdictions. However, should the authorisation be declared illegal on such ground, the document can be regularised by submitting it to the Regional Mission of the Environment Authority (MRAE). In addition, the energy-climate bill should provide a definitive solution to this issue.

Linky smart meter – One point of tension recently appeared around the use of communicating meters – also called smart meters – in France. These instruments receive energy consumption data in real time and transmit them instantly to the electricity distributor. Smart meters allow a more efficient management of distribution grids and individual electricity consumption, and can foster new forms of electricity consumption, such as self-consumption projects or smart grids. Enedis, the company in charge of 95% of France's distribution grid, has initiated efforts to deploy this technology using the so-called "Linky" meters. However, Enedis has been confronted by strong public opposition from consumers who refused the installation of such meters, which emit electromagnetic waves and can thus impact the health of certain consumers. The device also raises concerns in terms of personal data protection.

However, two recent Court rulings have paved the way for a quicker deployment of Linky meters across the country. The first one is a ruling issued by the *Conseil d'Etat* on July 11, 2019, stating that mayors cannot forbid the installation of Linky meters on their commune.

Another decision, given this time by the *Bordeaux Tribunal de Grande Instance*, rejected the action initiated by 200 consumers. The judges set aside all the arguments based on the violation of consumer law and GDPR, as well as those stressing potential risks for health. However, they did order Enedis to install anti-electromagnetic filters on the meters of 13 consumers who brought evidence that they suffered from electromagnetic hypersensitivity and were thus particularly exposed to Linky meters.

These decisions indicate that smart meters should keep on being implemented at a relatively fast pace in France, allowing a better management of electricity distribution grids, and fostering innovative techniques for the energy transition.

Planned suppression of Regulated Tariffs – Two recent decisions of the *Conseil d'Etat* opened the path to the suppression of regulated tariffs. Decision n°370321 of July 19, 2017 declared regulated tariffs on gas illegal on the ground that they impede the completion of the internal market, without following any objective of general interest. However, decision n°413688 of May 18, 2018 concluded in the opposite sense regarding electricity. Regulated tariffs should thus be kept in place for this sector, although their use will be necessarily restricted following the transposition of the Clean Energy Package in French law.

Major events or developments

In December 2017, EDF announced a plan to install 30 GW of solar capacities between 2020 and 2035 (€25 billion investment) exclusively in France, which could allow France to quadruple its solar energy capacities.

On July 2nd, 2019, the French Minister of Economy and Finance met with representatives from the Paris financial marketplace. They should adopt a carbon strategy by mid-2020, containing: (1) a global exit schedule for the financing of coal activities; (2) the marketing of green and inclusive financial products to the general public, within the framework established by the PACTE law; and (3) the definition of indicators for reporting on the achievements of financial actors in addressing climate change. The French Prudential Supervision and Resolution Authority (ACPR) and the *Autorité des Marchés Financiers* (AMF), responsible for supervising the French banking and insurance sectors, have announced the implementation of a mechanism for monitoring and evaluating those commitments.

Proposals for changes in laws or regulations

Energy-climate bill – On April 30, 2019, the French government launched an accelerated procedure (*procedure accélérée*) for the energy-climate bill. The mixed parity commission (*commission mixte paritaire*), composed of representatives from both the Senate and the National Assembly, reached an agreement on July 25, 2019. The bill still has to be voted in public session, but it should be published by the end of the year. Labelled as the "Energy-Climate Bill", this bill brings several welcome innovations and amends some aspects of the French legal framework resulting from the LTECV.

First, the Energy and Climate Bill tackles France's energy policy targets. Article 1 raises the aim to divide GHG emission by four to six and adds the objective to reach carbon neutrality by 2050. It also provides more ambitious objectives for fossil fuels (40% decrease of fossil energy consumption compared to 30% before) and renewable energies. It sets new targets in terms of offshore wind electricity (1GW/year of installed capacity in 2024); hydroelectricity; and green hydrogen (20 to 40% of low-carbon hydrogen in the total hydrogen mix in 2030). On the other hand, and in order to reach these objectives, the government pushed back the goal to reduce the share of nuclear energy in the total mix to 50% in 2025 to 2035.

Secondly, Chapter II provides general dispositions on climate. Article 2 provides a legislative ground for the High Council for Climate, created at the end of 2018. This panel of experts will be in charge of drafting reports on the government's energy and climate policy and any other report commissioned by the government or the Parliament. The bill also plans to shut down the last four coal centrals of the country. The section also tackles the energy efficiency of the building sector, setting more ambitious objectives especially regarding the most polluting constructions, and accelerating energy renovation processes.

Thirdly, the Bill brings some innovation to existing environmental evaluation dispositions. Article 4 clarifies the issue of the environmental authority to comply with the *Conseil d'Etat* decision. It highlights the interdiction to get both the consulting authority and the deciding entity in a position of conflict of interest. However, it does not designate the new environmental authority, leaving it up to the regulatory power to publish a decree following the publication of the bill. Article 4 *bis* AA creates experimentation contracts for "innovative renewable energies" and biogas energies; the competent administrative authority can organise a call for projects, the winner of which will benefit from a buying contract with EDF. Article 4 *ter* allows prefects to grant exemptions with regards to local Technological Risk Prevention Plans restrictions, to accelerate the implementation of renewable energy installations.

Chapter V is also noticeable as it addresses the transposition of the EU Clean Energy Package and provides further mechanisms to foster the development of renewable energies. For instance, it habilitates the government to use *ordonnances* – legal texts that do not need approval by the Parliament – to transpose the Clean Energy Package in the domestic legal order, and gives a definition of renewable energy communities similar to that of the directives. The Parliament has also brought more precision to the collective self-consumption regime. The perimeter of the activity should be restricted to the concerned building. The bill allows outsiders to monitor the installation. This Chapter also aims to contribute to solar development by allowing the installation of solar panels on certain routes and on rest and parking areas, and derogations to Local Plans of Urbanism (PLUs) for the installation of solar panels on parking areas.

Law on the orientation of mobilities – On November 26, 2018, the government started the accelerated procedure for the Orientation Law for Mobilities (*Loi d'orientation des mobilités*). Although less important in terms of energy policy than the LTECV or the Energy-Climate Bill, the bill does set ambitious objectives for the energy transition in the transport sector. The bill may open new business opportunities, especially in the hydrogen mobility sector.

For instance, the government plans to multiply by five the sales of electric cars before 2022, and to stop the sale of GHG-emitting cars by 2040. In order to achieve this objective, parking areas with more than 10 spots will be obliged to have at least one plug for electric cars.

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Overview of the current energy mix and the place in the market of different energy sources

The Federal Republic of Germany is pursuing rather ambitious goals with its energy transition. For example, renewable energies should account for at least 35% of gross electricity consumption by 2020, and at least 80% by 2050. At present, Germany seems to be on the right track in this respect: by 2018, the share of renewable energies in gross electricity consumption had already reached approx. 37.8%, so that the target for 2020 has already been met.[1]

This trend looks set to continue in 2019. In the first quarter of 2019, 62 billion kilowatt hours of electricity were generated from renewable energies and fed into the German electricity grid;[2] according to preliminary results of the Federal Statistical Office, this was an increase of 13.7% compared to the same quarter of the previous year. Overall, the share of electricity from renewable energies on the production side was 41.1%.

This development is primarily attributable to a very windy first quarter: the volume of electricity from wind power rose from 23.2% to 26.5% during this period. The share of electricity derived from biogas amounted to 5.1%; that of electricity generated from solar energy to 4.1%. On the other hand, the volume of coal produced fell considerably, by 20%. The decline in the amount of electricity produced from coal-fired power plants is due to the fact that coal-fired power plants often had to be ramped up and down in the first quarter of 2019 due to the high feed-in of electricity from renewable energies and their priority position. Nevertheless, coal remained the most important energy source for electricity generation with a share of 32%, followed by wind power (27%) and nuclear power (13%).

In general, wind energy has so far played a major role in the transition of energy systems. At 5,009 MW in 2017, the gross addition of onshore wind turbines significantly exceeded the gross addition path of 2,800 MW per year for the years 2017 to 2019 as specified in the Renewable Energies Act 2017 ("*Erneuerbare-Energien-Gesetz* 2017" – **EEG 2017**). The high increase in 2017 is particularly the result of pull-forward effects due to transitional regulations. In 2018, on the other hand, the net increase in onshore wind turbines fell to 2,273 MW, below the gross addition path anchored in the EEG 2017. The reasons for this decline may be the introduction of tenders in 2018 and increasing problems with the acceptance of wind energy projects. Whether the goals of the energy transition in Germany can be achieved will depend to a large extent on how the dynamics of the expansion of wind energy continue to develop.[3]

Developments in government policy/strategy/approach

In the coalition agreement of the current 19th legislative period of the German federal parliament,[4] which was concluded on 7 February 2018 between the governing parties CDU, CSU and SPD, the government set itself the goal of continuing the expansion of renewable energies and achieving a 65% share of renewable energies in the energy mix by 2030. This is intended, in particular, to cover the additional electricity required to achieve the climate targets for transport, buildings and industry.

The coalition agreement sees the greatest challenge in the expansion of renewable energies in the capacity of the grids. Therefore, while on the one hand, the expansion of the grid must be accelerated, on the other, the existing electricity grids need to be optimised and better utilised through closer cooperation between the grid operators and new technologies. The Federal Ministry of Economics and Energy has accordingly presented an "Electricity Grid Action Plan", which provides for several measures to meet the objectives of the coalition's revenue. An important part of the action plan is the amendment to the "Network Expansion Acceleration Act for the Transmission Grid" ("*Netzausbaubeschleunigungsgesetz Übertragungsnetz*" – **NABEG**).[5] This amendment essentially simplified and accelerated the approval procedure for the expansion, reinforcement and optimisation of power lines. The amendment came into force on 17 May 2019.

In addition, the coalition agreement provides for a federal energy efficiency strategy to be developed with the aim of reducing energy consumption by 50 % by 2050. Accordingly, a draft law for a new "Building Energy Act"[6] is currently available, which is intended to bring together the existing energy regulations for the building sector. In line with the requirements of the coalition agreement, the draft law does not provide for a tightening of the current building standards. The law is scheduled to come into force at the end of 2019.

The coalition agreement also addresses the topic of sector coupling: it is intended to promote linking the heat, mobility and electricity sectors in connection with storage technologies. For this purpose, the framework conditions are to be adapted; however, the coalition agreement does not mention any concrete measures, nor have any such measures yet been implemented.

The governing parties also stipulate in the coalition agreement that the commission "Growth, Structural Change and Employment", involving various actors will be set up to work out a plan for the gradual reduction and discontinuation of coal-fired power generation, including the necessary legal, economic, social and structural measures. The appointment of the Commission was accordingly decided by the Federal Government on 6 June 2018. On 26 January 2019, the Commission presented its final report, which foresees a path towards the gradual phasing-out of coal-fired power generation by 2038, if possible by 2035 (see below). This makes Germany the only industrialised country to opt out of both nuclear and coal energy.

Developments in legislation or regulation

<u>Energy Collective Act</u>

Probably the most substantial changes in the legal framework of the energy market in the past year result from the Energy Collective Act. The Act came into force on 21 December 2018, amending the EEG, the Combined Heat and Power Act ("*Kraft-Wärme-Kopplungsgesetz*" – **KWKG**), the Energy Industry Act ("*Energiewirtschaftsgesetz*" – **EnWG**) and other energy regulations.[7] These changes were originally planned for the "100-

day law", which, however, was not passed in time due to differing views within the coalition, and finally was renamed the Energy Collective Act ("*Energiesammelgesetz*"). The Energy Collective Act implemented various urgent legislative requirements in the energy sector in order to further ensure the purposeful and efficient expansion of renewable energies.

A major part of the amendments of the Energy Collective Act affects the EEG 2017, in particular, the regulations regarding certain tenders, and the remuneration. One of these changes introduced into the EEG 2017 is the legal anchoring of the special invitations to tender for solar and onshore wind power plants. In total, an additional 4,000 MW each are to be put out to tender by 2021. For the regular tenders, the volumes for onshore wind energy and solar energy were slightly reduced.

In order to counter the expected lower realisation of onshore wind energy projects, the legislator has also shortened the realisation period for onshore wind turbines, which benefit from an award in the first three bid dates in 2019, from 30 to 24 months. If an onshore project is not realised within this period, the award expires.

The Energy Collection Act also resulted in slight changes for the tenders for biomass plants: the tender frequency was changed from one bid date per year to two bid dates per year, while the tender volume remains the same. This amendment aims to strengthen competition and avoid delays.

In addition, the Energy Collective Act was accompanied by successive cuts in financial support for solar plants on buildings with an output of between 40 and 750 kW. The tenant electricity surcharge for solar power generation was also reduced. It remains to be seen whether tenant electricity models can still be implemented profitably in the future.

Moreover, the Act also adapts the regulations for the partial exemption of new combined heat and power (CHP) plants from the EEG levy. This adjustment was necessary in order to comply with the EU Commission's state aid rules.

As a further result of the amendments, the EEG 2017 now contains an obligation for wind turbine operators to provide night-time identification in line with demand. These are devices that only flash red at night when an aircraft is nearby. The equipment obligation, which aims, in particular, to strengthen the acceptance of wind energy by residents, applies both to new plants and (after a transitional period) to existing plants.

The KWKG has also been amended by the Energy Collection Act, especially regarding the granting of the CHP surcharge for existing and modernised CHP plants. In particular, the CHP surcharge for existing plants was reduced, as an evaluation of the support rates showed that there was excessive support for CHP plants, due to significantly lower gas prices. The changes implemented in the EnWG relate, in particular, to the formation of the capacity reserve and the grid connection conditions according to the provisions of European law.

Modernisation of the Grid Fee Structure

The Act to Modernise the Grid Fee Structure ("*Gesetz zur Modernisierung der Netzentgeltstruktur*" – NEMoG),[8] which has been in force since July 2017, contains two important regulations: firstly, the gradual standardisation of transmission grid fees; and secondly, the reduction of the privilege of avoided network charges.

The transmission grid fees will be gradually adjusted nationwide by the NEMoG and a corresponding ordinance of the federal government. Since 1 January 2019, transmission grid fees are being standardised in five stages. In the 2019 calendar year, the transmission grid charges, for 20% of the revenue caps relevant for the formation of charges, will be determined on a nationwide basis. In subsequent years, this share of revenue caps will increase by 20%. Starting in calendar year 2023, the transmission grid fees will then be fully calculated nationwide. The aim of these regulations is to reduce regional cost differences and thus ultimately to achieve a more equitable distribution of electricity costs. At present, grid fees account for about 25% of the total costs of electricity grids.[9]

In addition, the NEMoG amended the regulations for avoided network charges. For volatile new plants, these fees were completely suspended from 2018; for existing plants, the avoided grid fees have been successively suspended in three steps since 2018 until 2020. From 2023 onwards, new, decentralised generation plants will also no longer receive payments from avoided grid fees. These adjustments are based, in particular, on the fact that the earlier assumption, that locally generated and consumed electricity would save costs for the higher-level grid, does not correspond to the actual circumstances. In order to ensure that the costs of the energy shift in the grid fees continue to be distributed fairly and transparently, it was necessary to adjust the avoided grid fees.[10]

Capacity Reserve Regulation

The conversion of the energy supply to renewable energies naturally brings challenges for the security of supply: renewable energies such as wind and solar energy are subject to natural fluctuations. In addition, the generation of electricity from wind and sun often takes place at a great distance from the central consumption points. In the future, electricity grids will therefore have to be able to transport large generation capacities flexibly. On the other hand, the electricity market must be prepared for unforeseeable extreme situations in which additional capacities are required somewhere.[11]

For this reason, the formation of a capacity reserve was already legally anchored in Section 13e EnWG in 2016. A capacity reserve shall be used if, despite free price formation, there is insufficient supply on the electricity exchange to enable a balance between supply and demand. Originally, such a reserve was planned to be established gradually from the winter half-year 2017/2018 onwards. However, the formation of the reserve was postponed several times, most recently by the Energy Collection Act until the winter half-year 2020/2021. The Capacity Reserve Regulation,[12] which came into force in February 2019, now regulates the procedure for the procurement, use and settlement of the capacity reserve.

The capacity reserve will consist of generation plants, loads and storage facilities, which are selected for a period of two years by the transmission grid operators. Plants in the capacity reserve are located outside the market, i.e. these plants are only used when required at the request of the transmission grid operators and otherwise do not participate in the electricity market. By this means, competition distortions will be avoided. The operators of the plants in the capacity reserve receive an annual remuneration for their participation. The capacity reserve will initially be formed in the amount of 2 GW; the required amount is then regularly reviewed by the Federal Ministry of economics and energy. The invitation to tender for the formation of the capacity reserve for the first supply period from 1 October 2020 to 30 September 2022 will be carried out by the transmission system operators on 1 December 2019. It remains to be seen for which type of plants the participation in the capacity reserve will be of interest, and whether the reserve will be formed to the extent envisaged.

Judicial decisions, court judgments, results of public enquiries

ECJ: EEG 2012 is not state aid

On 28 March 2019, the Court of Justice of the European Union (**ECJ**) ruled in the final instance that the promotion of renewable energies and the special compensation scheme for electricity cost-intensive companies under the EEG 2012 did not constitute state aid (Case C-405/16 P).[13] In November 2014, the European Commission classified both the renewable energy support and the special compensation scheme as aid (decision of 25 November 2014 on the aid scheme SA.33995 (2013/C) (ex 2013/NN)).[14] The European Court dismissed the action brought by Germany against the ruling at first instance.[15] However, the ECJ has now upheld the action, set aside the ruling of the European Court and annulled the commission's decision of November 2014.

The ECJ thus follows Germany's view that the EEG 2012 does not constitute aid within the meaning of Art. 107 (1) TFEU. The promotion of EEG plant operators is not financed from state resources, but via a private-sector levy system financed by end consumers. The measure is not attributable to the state since the state has no executive function in the course of the implementation of the EEG levy.

The ruling of the ECJ is of great relevance especially for electricity cost-intensive companies: due to the original decision of the European Commission, limitation decisions were partially revoked in 2013 and 2014. As a result, any amounts paid in excess will now be refunded to the companies concerned.

The decision also has a significant impact on the future energy policy. Due to the fact that state aid control is no longer necessary, the legislator has further options to promote renewable energies. In addition, far-reaching consequences could result from the judgment for other ranges of the energy industry, for instance, in connection with grid fees. In May 2018, the EU Commission decided that grid fee exemptions for certain electricity cost-intensive companies in 2012 and 2013 violated EU state aid law.[16] A number of affected companies filed actions for annulment before the European Court. Following the ruling of the ECJ, the prospects of success of these actions have now increased significantly, as against this background the argument that network fee exemptions were not granted "from state funds" also seems reasonable.

Federal Court of Justice: Equity interest rate for gas and electricity networks

On 9 July 2019, the German Federal Court of Justice made a surprising decision of great commercial significance for both electricity and gas network operators and electricity and gas customers:[17] the Court ruled that the Federal Network Agency determined the rates of return on equity for the third regulatory period correctly. The Federal Court of Justice thus set aside a ruling of the Higher Regional Court Düsseldorf from March 2019,[18] which classified the fixed equity interest rates as too low and accused the Federal Network Agency of making an incorrect calculation. After the clear decision of the Higher Regional Court, the decision of the Federal Court came as a surprise to the network operators.

The return on equity indicates the return that network operators can achieve from their investments. The low setting of the equity interest rates for the third regulatory period leads to an approximately $^1/_4$ lower return for network operators compared to the last regulatory period. They must therefore reckon with lower network charges. For electricity and gas customers, on the other hand, the surprising decision of the Federal Court of Justice is good news, as the burden of the network charges is at least limited.

Higher Regional Court Düsseldorf: German balancing energy market

On 22 July 2019, the Higher Regional Court Düsseldorf declared the controversial mixed-price procedure on the German balancing energy market to be against the law.[19]

Since October 2018, the mixed-price procedure has determined pricing on the balancing energy markets. The award of the contract for balancing energy quantities thereafter takes place on the basis of a mixed price, consisting of the performance price and a weighted commodity price. The purpose of this procedure was to prevent the possibility of abuse that the previously applicable pricing procedure had revealed. However, the mixed-price procedure introduced at that time was often subject to criticism. In particular, it was criticised that the procedure structurally discriminated against renewable energies, as conventional power plants with high performance and low operating prices were systematically preferred. In addition, the total costs of balancing energy had been driven up by the mixed-price method.

In its decision, the Higher Regional Court Düsseldorf judged the mixed-price procedure to be excessive intervention for market participants, and therefore declared it to be unlawful. As a result, the previously valid tender procedure on the basis of performance prices will be revived. In the medium term, the balancing energy market is then to be fundamentally reorganised by the introduction of balancing labour markets, as prescribed by European law.

Major events or developments

Stagnating expansion of wind energy

Wind energy in Germany is an important driver for the transition of energy systems. However, the expansion of onshore wind energy is currently stagnating. The tenders introduced in 2017 to determine the amount of funding under the EEG 2017 were clearly undersigned on all bid dates in 2019.[20] In the last bid date on 1 September 2019, only 176 MW of the 500 MW put out to tender were awarded.[21] The tendered bidders benefited from the low level of participation, so that the average volume-weighted surcharge value of 6.20 ct/kWh corresponded to the fixed maximum value. In particular, long approval procedures, missing land for wind energy, and a large number of objections are held responsible for the stagnating expansion of onshore wind energy.

In view of these developments, a "wind summit" took place in September 2019 at the Federal Ministry of Economics and Energy to which representatives of the industry, the federal states and environmental associations were invited. In the run-up to the summit, various associations presented a 10-point programme for the expansion of wind energy, which contained proposals for ensuring the availability of land, the manageability of nature conservation requirements and for strengthening local capacity.[22] The conclusion of the summit was that in the following weeks, the Federal Ministry of Economics and Energy will develop a plan for concrete measures to accelerate approval procedures and make more land available for wind energy.[23] It remains to be seen how these proposals will be implemented in detail.

Shortfall in the German electricity system

In June 2019, the German electricity grid was significantly undersupplied for three days. The shortfall was so significant that the four transmission grid operators in Germany had to call up reserves of balancing energy throughout Europe because twice as much balancing energy as had been booked in advance was unexpectedly required. Following these bottlenecks, electricity prices on the energy exchange increased significantly for a short time.

How this imbalance in the German electricity market could have occurred has not yet been conclusively clarified. It is assumed that mis-speculation by electricity traders was the cause. (In general, electricity traders must ensure that generation and electricity consumption in their area of responsibility are always balanced.) In order to avoid the purchase of expensive energy on the spot market, some electricity traders may have speculated that there would be enough balancing energy available in the event of an undersupply of the grid.

In the wake of these events, the Federal Network Agency submitted a package of measures to strengthen balancing group loyalty for consultation in July 2019.[24] It is intended to adjust the calculation method for the formation of the balancing energy price by, among other things, tightening existing penalties. In addition, reform proposals for calculating the balancing energy price are to be submitted to the Federal Network Agency for approval. By linking this price to a suitable stock market price index, it is intended to eliminate incentives to exploit price differences. Market participants are also to be obliged to settle their balancing groups at an earlier date in order to prevent systematic short-selling immediately before physical fulfilment.

Furthermore, in view of the incidents, the Federal Network Agency once again urged all market players to comply with their legal obligations. In addition, the regulatory authority reserved the right to initiate supervisory measures in case of suspicion of deliberate manipulation of energy forecasts or unlawful arbitrage transactions on the balancing energy price.

Power Purchase Agreements

Long-term Power Purchase Agreements (**PPAs**) in the renewable energy sector are gaining ground in Germany.[25] This is not least due to the fact that, from 2021 onwards, the 20-year subsidy under the Renewable Energy Sources Act will end for many existing plants, so that plant operators will have to evaluate new ways of marketing. Although some new plants are already being operated today without EEG support, the majority of renewable energy plants are still being supported under the EEG.

Nevertheless, the players on the German market are also increasingly concerned about alternative marketing models. PPAs are currently discussed in this respect. PPAs are contracts between plant operators and large electricity suppliers, which can have different structures. While PPAs themselves are not a new way of marketing, their application in renewable energy projects is new. It therefore remains to be seen which standards will develop for such contracts.

There are already larger-example cases in Germany. EnBW AG and Energiekontor AG recently concluded a 15-year PPA for subsidy-free solar parks in Germany. It is likely to be the first electricity purchase agreement for a photovoltaic project of this size. "The agreement stipulates that EnBW will purchase 100% of the electricity at a fixed price. Within the framework of the agreed contract term of 15 years, the two companies assume that the total amount of electricity produced will be around 1.3 terawatt hours," the companies stated.[26] According to press releases, Deutsche Bahn AG recently also concluded a PPA for 25 MW of capacity from an offshore wind farm, which is the first offshore PPA in Germany.[27]

E.ON/RWE Merger

In May 2018, the major German energy suppliers E.ON and RWE announced their intention to merge: RWE is to transfer 76.8% of its shares in innogy SE to E.ON after the renewable business has been removed from innogy and transferred to RWE. In return, RWE will receive E.ON's renewable business, a payment of €1.5 billion and shares in E.ON with a nominal value of 16.67%. This transaction aims to result in two strengthened European energy companies.

Before this transaction can be carried out, however, it must pass the European and German merger control.[28] In January 2019, RWE announced the acquisition of the renewables business of E.ON and innogy to the European Commission for review. This part of the planned transaction was approved by the EU Commission on 26 February 2019. RWE may thus take over E.ON's generation capacities and become the central supplier of both conventional and renewable generation capacities in Germany. On the same day, the Federal Cartel Office ("*Bundeskartellamt*" – **BKartA**) announced that it considers RWE's acquisition of the 16.67 % stake in E.ON to be unobjectionable.[29] The EU Commission's approval of E.ON's acquisition of 76.8% of the shares in innogy SE is still pending. The Commission is currently examining whether E.ON's acquisition of the networks and distribution activities of RWE subsidiary innogy is compatible with the common market. The EU Commission's preliminary deadline for the E.ON/RWE merger expires on 20 September 2019. The Commission will then decide whether, and under what conditions, it will approve the final part of the planned merger.

This decision has enormous implications for the energy industry. It is feared that the planned exchange of parts of the company with E.ON could create a new electricity giant which could dominate large parts of the market and prices.

Proposals for changes in laws or regulations

Coal Commission

As agreed in the coalition agreement, the German Federal Government decided on 6 June 2018 to set up the "Growth, Structural Change and Employment" Commission (unofficially the "Coal Commission") in order to draw up a plan for a climate- and socially compatible exit from coal as well as concrete proposals for growth and employment in the affected regions. The members of the Commission represent a broad cross-section of social, political and economic actors. In drawing up the recommendations, the Commission has therefore consulted numerous scientists and interest groups, discussed the state of knowledge and the facts in detail, and weighed the various positions against each other.

The Commission presented its final report on 26 January 2019.[30] In this report, the Commission recommends the end of coal-fired power generation in Germany by 2038 at the latest. As intermediate steps, reductions in coal capacities to 30 GW in 2022 and 17 GW in 2030 are planned. In 2032, a review will be carried out to determine whether it will be possible to stop coal-fired power generation in Germany as early as 2035. For lignite-fired power plants that have already been built but are not yet in operation, a negotiated solution is to be sought so that these power plants are not put into operation. Should this not succeed, regulatory solutions and compensation should be considered between 2023 and 2030. For coal-fired power plants, voluntary decommissioning premiums are to be paid, which will gradually decrease by 2030.

In addition, the report shows how economic structural change can succeed in the regions concerned. In order to support these regions in their structural change, the report proposes funds of over €40 billion. In order to implement the Commission's structural policy recommendations, a draft law on structural strengthening was prepared and adopted by the Federal Cabinet at the end of August.[31]

The legislative implementation of the Commission's energy policy proposals is currently being prepared. A corresponding law is to be presented in autumn 2019 so that the legislative process can be completed by 2019.

Planned changes of EEG and KWKG

The law amending the law on energy services and other energy efficiency measures ("*Energiedienstleistungsgesetz*" – **EDL-G**[32]), which was passed in the German parliament on 27 June 2019, not only further develops and simplifies the regulations on mandatory energy audits. The law also contains further amendments, in particular to take account of the ruling of the European Court of Justice on the state aid character of the EEG 2012 (see above).[33]

Since, from a German perspective, the ruling can also be applied to the KWKG, the German legislator has decided to remove the European Commission's approval reservations under state aid law in the KWKG. Due to the previous reservation of approval, support for existing CHP plants was suspended for the year 2019. This led to a noticeable deterioration in the economic situation of plant operators. With the abolition of the approval reservation, the subsidy for existing plants can now be granted.

In addition, the legislator set the EEG levy for self-supply from CHP plants back to 40%, with retroactive effect to 1 January 2019. Furthermore, the EEG 2017 also lifts various approval reservations under state aid law.

The EDL-G still requires the approval of the Federal Council, which is expected to decide on it at its next plenary session on 20 September 2019.

Regulatory framework for energy storages

Due to the fact that the generation of electricity from wind and solar power plants depends on the weather and not on the demand for electricity, energy storage facilities will be playing an increasingly important role in the energy transition. Energy storages could ensure the security of supply and reliability of the power supply even with increased use of renewable energies. Accordingly, the regulatory framework for electricity storage facilities was gradually improved by the legislator: with the introduction of the EEG in 2017, the double burden of the EEG levy on both the fed-in and fed-out quantities of electricity was discontinued. Under certain conditions, it is also possible to exempt energy storage facilities from grid charges for a period of 15 years from commissioning.

In the future, the regulatory framework for energy storage is to be further improved: the European Union's new directive 2019/944 on common rules for the internal market for electricity and amending Directive 2012/27/EU,[34] which came into force on 4 July 2019, stipulates that storage facilities providing grid services such as balancing energy will in future be treated equally with other power plant technologies. This means, for example, that storage facilities will be given their own grid connection entitlement. In addition, the double burden of taxes and levies on energy storage facilities is to be eliminated if the storage facilities provide network services. This would mean that energy storage facilities in Germany would no longer be burdened twice with statutory levies and concession fees.

As part of an EU Directive, these regulations do not apply directly, but must be implemented by the Member States. The Member States have until 31 December 2020 to implement the Directive.[35]

* * *

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Ghana

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Overview of the current energy mix, and the place in the market of different energy sources

Industry regulators and players

Ghana's current energy mix comprises: (a) electrical energy as produced from hydro, thermal and renewable sources; and (b) petroleum comprising crude oil and natural gas. The Ministry of Energy is the sector Ministry with responsibility for policy formulation, implementation, monitoring and evaluation.

Key players in the electricity sector are: (a) the Energy Commission, which is the licensing authority of electricity utilities with further statutory responsibilities for setting technical standards; (b) the Public Utilities Regulatory Commission (PURC), with responsibility for regulating and providing rates chargeable for utility services; (c) Ghana Grid Company (GRIDCo), with responsibility for the transmission functions of the electricity sector; (d) Power Distribution Services Ghana Limited (PDS)/Electricity Company of Ghana (ECG)[1] and the Northern Electricity Distribution Company (NEDCo), with responsibility for the distribution of electricity throughout the country; and (e) various state-owned and independent power producers, the biggest and longest-standing of which is the Volta River Authority (VRA).

The Petroleum Commission and the National Petroleum Authority respectively, regulate the upstream and downstream petroleum industries. Ghana has one gas processing plant located at Atuabo in the Western Region, operated by the Ghana National Gas Company (Ghana Gas). Ghana Gas is a subsidiary of the Ghana National Petroleum Corporation (GNPC), a state-owned entity tasked with reducing Ghana's dependence on imports through the development of the country's own petroleum resources. It holds a transmission licence from the Energy Commission, which mandates it to install and operate a national interconnected transmission system for the transmission throughout Ghana of natural gas. The GNPC is partner in all petroleum agreements in Ghana. The Tema Oil Refinery (TOR) is the country's major petroleum refinery,[2] with a capacity of 60,000 barrels per day. The Bulk Oil Storage and Transportation Company Limited (BOST), with its network of storage and pipeline infrastructure, is a wholly state-owned company responsible for the distribution of refined petroleum products.

In 2016, the increasing debt of state-owned energy operators such as TOR, VRA, NEDCo and the ECG (resulting from low collection rates and below-cost recovery pricing), caused the Government to establish the ESLA PLC, a public limited liability company charged with issuing long-term bonds to pay energy sector debts due to banks and trade creditors. The securities issued by ESLA are backed by receivables emanating from the Energy Sector Levy which is imposed under the Energy Sector Levies Act, 2015 (Act 899).[3]

Electricity

There are currently three hydro-electric dams, all on the Volta River and all state-owned, with a combined installed capacity of 1,580MW contributing to the country's generating capacity:

(a) The Akosombo dam is owned and operated by the Volta River Authority (VRA), established in April 1961.

(b) The VRA also operates the plant at Kpong.

(c) The nation's other hydro power generation plant is located at Bui and is owned by the Bui Power Authority (BPA).

The first thermal generation plant, the Takoradi thermal power plant, came on stream in 1997. Currently, the VRA owns a number of thermal plants located in Aboadze near Takoradi, and within the Tema enclave, with a combined generation capacity of 1,292MW. These thermal facilities operate on a combined cycle and include: the 330MW Takoradi Thermal 1 (T1) Power Plant; the 340MW Takoradi Thermal 2 (T2) Power Plant, which is a Joint Venture (JV) between VRA and TAQA from Abu Dhabi; a 110MW Tema Thermal 1 Power Plant (TT1PP); a 80MW Mines Reserve Plant (MRP); the 49.5MW Tema Thermal 2 Power Plant (TT2PP); the 38MW Tema Thermal 2 Plant Expansion (TT2PP-X); and the 220MW Kpone Thermal Power Plant (KTPP).[4] Due to the energy sector reform embarked on by the country from 1994,[5] there are also other Independent Power Producers (IPPs) contributing to the energy generation capacity of the country. Notable among them are Ameri, Karpower, Sunon-Asogli and Cenit.[6]

With the passage of the Renewable Energy Act in 2011, focus was shifted to encouraging the production of electricity from renewable sources. The Renewable Energy Act requires an electricity distribution utility or bulk customer to procure a specified percentage of its total purchase of electricity from renewable energy sources and provides, in terms of incentives, a guaranteed feed-in tariff for 10 years to renewable energy producers. The policy objective of the country is stated to be to source at least 10% of its energy requirements from renewables.[7] Currently, two solar power plants, VRA Solar and BXC Solar, are operational, contributing about 0.22% to the total electric energy mix of the country. The contribution of renewable energy to the mix was bolstered by the commissioning of a 20MW solar plant at Gomoa Onyadze in the Central Region of Ghana on 15 September 2018.

In the 2019 Electricity Supply Plan of the Electricity Supply Plan Committee, Ghana's power generation mix at the end of 2018 is reported to have been 39.60% hydro, 58.14% thermal and 2.26% import. Its installed capacity at the end of that period was quoted as 5,083 MW. The country is reported to have an excess capacity of about 1,700MW (±3%). This situation has been partly attributed to self-generation plants which have been installed as alternatives or back-up to the grid supply. These are estimated to represent about 500MW.[8] At the height of the energy crisis, non-residential and industrial consumers began to depend on diesel-operated generators as a more reliable and, in some cases, cheaper alternative to power supplied from the national grid.

Oil and gas

Ghana discovered crude oil in commercial quantities in 2007 and commenced the commercial production of crude oil and gas in 2011. The country currently has three major oil fields: Jubilee, SGN and TEN. The Public Interest and Accountability Committee (PIAC) is a statutory body set up under the Petroleum Revenue Management Act, 2011 (Act 815) with a mandate to promote transparency and accountability in the management of petroleum revenues. In its report on the Management of Petroleum Revenues for 2018, the country's total crude oil production for 2018 was reported to be 62,135,435.07 barrels: Jubilee Field produced 28,461,775 barrels, representing forty-five per cent (45%) of total production, whilst TEN and SGN produced 23,557,361 barrels (38%) and 10,751,671 barrels (17%), respectively. This represented a 5.93% increase on the 2017 figure of 58,658,063.54 barrels.

The report further indicates that a total of 91,459.30 million standard cubic feet (MMScf) of associated gas was produced from the Jubilee, TEN and SGN fields in 2017. Jubilee produced 44,841.94 MMScf, while TEN produced 39,472.78 MMScf. Gas production from the SGN field commenced in June 2018 and totalled 7,144.58 MMScf for the year.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The following developments are worthy of mention:

It has been reported that the PDS/ECG owes IPPs about US$700 million. Prior to PDS taking over ECG's operations, ECG owed the IPPs US$400 million. A further US$300 million has been accumulated since PDS took over the operations of ECG. PDS has made no payment to these IPPs since the said takeover. In the circumstances, the IPPs are threatening to shut down their operations and, considering they have a supply capacity of 1,500 megawatts of electricity, such step would have serious consequences for the country's ability to meet the demand of consumers.

In the 2017 report of PIAC on the Management of Petroleum Revenues, it is noted that the Government of Togo or its authorities were making adverse claims concerning its maritime boundary with Ghana in respect of the East Keta Ultra Deep Block. In the 2018 report, however, PIAC commends the Government of Ghana for engaging the Togolese authorities with a view to settling the dispute. The outcome of this engagement would have consequences for Ghana's future oil production and potential for generating revenue through the development of the oil fields located in that area.

The Government has at different fora expressed concern about the feed-in-tariffs agreed to in the various power purchase agreements (PPAs) negotiated between 2012 and 2015 at the height of the power crisis in the country.[9] To this end, it instigated the review of these PPAs. Some of the findings from the review were that the feed-in-tariffs were excessive, with some ranging upwards of US$0.18 per kilowatt hour.[10] The Government's stated policy is to renegotiate these PPAs with a view to, among other things, reducing the feed-in-tariffs to US$0.10 or less.

Among the entities whose PPAs were renegotiated is Karpower Ghana Company Limited. The results of the renegotiation were an extension of the duration of the PPA from 10 to 20 years, and the relocation in August of 2019 of the power plant from Tema to the naval base in Takoradi. The expressed idea for the relocation is to make use of the country's gas resources from the Western Enclave by converting the plant from reliance on heavy fuel oil (HFO) to the relatively cheaper natural gas available in Takoradi.

Further, future PPAs are also to be subjected to a process of competitive bidding where prospective power producers are required to bid for power projects proposed by the Government. This is to engender competition and, hopefully, provide the country with cheaper power. Closely aligned to this policy is the Government's decision to renegotiate the timelines for the commencement of generation of power under the various PPAs signed with the ECG. The review found that production of power under most of the PPAs was scheduled to commence at about the same time, with the result that the country would have increased its generating capacity without the commensurate demand.

Developments in government policy/strategy/approach

Renewable Energy Master Plan 2019[11]

Ghana's Renewable Energy Sector Master Plan has been developed to address the attendant effects of short-term planning in the overall development of the renewable energy sector, and to provide an investment-focused framework for the promotion and development of the country's renewable energy resources for sustainable economic growth, contribute to improved social life and reduce adverse climate change effects.[12]

The Plan seeks to achieve the following by 2030: increase the proportion of renewable energy in the national energy generation mix from the 2015 baseline to 1,363.63 MW (with grid-connected systems totalling 1,094.63 MW); reduce the dependence on biomass as the main fuel for thermal energy applications; provide renewable energy-based decentralised electrification options in 1,000 off-grid communities; and promote local content and local participation in the renewable energy industry.[13] The implementation of the Plan, which commences from 2019, will be executed in three cycles with the first cycle (or transition phase) running from 2019 to 2020 and subsequent cycles, running from 2021 to 2025 and 2026 to 2030.[14]

Energy sector policy

It is reported that a new National Energy Policy has been drafted to provide the framework for guiding operations within Ghana's energy sector and also ensure a fair balance between the aspirations of Government and the interests of industry players, academia, local communities, civil society and other key stakeholders.[15] The draft Policy was subject to a nationwide stakeholder consultation in the first Quarter of 2018 and is being finalised by the Ministry of Energy in collaboration with the Energy Commission, for submission to Cabinet.[16]

Solar Lantern program

It is reported that a total of 24,770 Solar Lanterns were sold as at September 2018, at 70% subsidy, to poor off-grid rural households with an additional 100,000 units to be procured as part of the target to totally eradicate kerosene lanterns as the main lighting fuel for non-electrified communities.[17] It is reported that the demand for kerosene as fuel for lighting has significantly reduced.[18]

Off-grid electrification

It is reported that solar micro-grids have been completed and commissioned in 26 remote health facilities in Brong Ahafo, Northern and Western regions to provide basic electricity as part of Government efforts to achieve universal access by 2020.[19]

Utility scale renewable energy

It is reported that procurement processes are under way for Volta River Authority and Bui Power Authority to add a total of 167 MW of renewable energy from solar, wind and hydro to the national grid.[20]

Nuclear energy

The Government has signed an Inter Government Agreement (IGA) with China National Nuclear Corporation (CNNC) to deepen Ghana's cooperation with China in the field of peaceful use of nuclear energy in August 2018.[21] It is reported that a preliminary site assessment has been completed for the candidate areas to site the first nuclear power plant; and an integrated work plan for the nuclear programme has been reviewed and is being implemented with the assistance of the International Atomic Energy Agency (IAEA).[22]

Developments in legislation or regulation

Energy Sector Levies (Amendment) Act 2019

The Energy Sector Levies Act, 2015 imposed six different levies which are outlined in its first schedule as follows: (a) Energy Debt Recovery Levy; (b) Road Fund Levy; (c) Energy Fund Levy; (d) Price Stabilisation and Recovery Levy; (e) Public Lighting Levy; and (f) National Electrification Scheme Levy. The Energy Sector Levies (Amendment) Act, 2019 (Act 997) increased the rates at which the Energy Debt Recovery Levy, Road Fund Levy and the Price Stabilisation and Recover Levy are charged.

Petroleum (Exploration and Production) (General) Regulations 2018, (L.I. 2359)

L.I. 2359 provides for matters necessary for carrying out or giving effect to the Petroleum (Exploration and Production) Act, 2016 (Act 919), including operating standards to be observed by operators, the requirement for regular reporting to the Petroleum Commission, a fiscal regime, and regulations regarding lifting, marketing and pricing of petroleum.

Judicial decisions, court judgments, results of public enquiries

Seadrill Ghana Operations Limited v. Tullow Ghana Limited [2018] EWHC 1640

Tullow Ghana Limited ("Tullow Ghana") hired from Seadrill Ghana Operations Limited ("Seadrill Ghana") an ultra-deep water semi-submersible rig, West Leo. The contract, initially entered into on 3 November 2011, was for one year but a three-year contract was later agreed with an option to increase by a further two years. That option was exercised by Tullow Ghana on 15 December 2012 so that the three-year contract was amended to a five-year contract. Pursuant to the contract, Tullow Ghana was obliged to pay a daily operating rate of hire of the order of US$600,000.

In October 2016, Tullow Ghana sent a notice of *force majeure* to Seadrill Ghana in respect of the West Leo contract. Tullow Ghana claimed that the field the rig had been hired for was subject to a drilling moratorium by the government of Ghana. The moratorium was in place due to proceedings before the International Tribunal for the Law of the Sea (ITLOS) to determine the delineation of the disputed maritime boundary between Ghana and Ivory Coast in the Atlantic Ocean. The moratorium was pursuant to the Provisional Measures Order of the Tribunal that "Ghana shall take all necessary steps to ensure that no new drilling either by Ghana or under its control takes place in the disputed area." Tullow Ghana unilaterally terminated the rig contract in December 2016.

The High Court in England held that Tullow Ghana was not entitled to terminate its West Leo rig contract with Seadrill Ghana by invoking the contract's *force majeure* provisions. The Provisional Measures Orders of ITLOS did not disable Tullow from fulfilling its obligation by providing a drilling programme to Seadrill in relation to the Greater Jubilee Fields, which were not part of the disputed area. The unwillingness of the Government of Ghana to approve the Greater Jubilee Plan was not an event of *force majeure*, given the limits that the contractual provision imposed on the meaning of that term.

Major events or developments

Bidding for offshore exploration blocks

In March 2018, the then Minister for Energy, Hon. Boakye Agyarko, inaugurated the Licensing Bid Rounds and Negotiation (LBRN) Committee to supervise the open competitive bidding for Ghana's oil blocks to prospective oil exploration companies. The committee is required, among other things, to: prepare all the necessary documentation for a successful bid round; assess and package all the data on the acreages; set up an online data room where all the data can be accessed by prospective bidders; embark on promotions and roadshows in collaboration with the Petroleum Commission; invite bids from prospective applicants and examine them to make sure they meet the requirement of applicable law; carry out pre-qualification of applicants in line with applicable regulations; evaluate qualified bids and select winners in line with transparent criteria; and negotiate with the winners of the bids and provide recommendations to the minister for signing the petroleum agreement.

On 15 October 2018, the LBRN Committee set up in March 2018 opened bidding for three offshore exploration blocks. It is reported that 16 oil and gas firms including Tullow Oil, Total, ENI, Cairn, Harmony Oil and Gas Corporation, ExxonMobil, CNOOC, Qatar Petroleum, BP, Vitol, Global Petroleum Group, Aker Energy, First E&P, Kosmos, Sasol and Equinor submitted applications for one or more of five Ghanaian offshore blocks in the first exploration licensing round.[23] It is reported that the Minister of Energy indicated that the pre-qualified companies had up to 21 May 2019 to submit their bids, while the final award of contract to successful bidders was expected to be made on 31 August 2019.[24]

Investigations relating to Power Distribution Services Ghana Limited's guarantee

As part of efforts to re-organise the power sector through private sector participation under the Millennium Challenge Compact, PDS, as concessionaires under a concession agreement between PDS and ECG, became the electricity distribution service provider in all of ECG's operational areas in the southern distribution zone of Ghana. On 30 July 2019, the concession agreement between PDS and ECG was suspended by the Government due to alleged fundamental and material breaches. According to the Government, PDS had failed to provide demand guarantees for the agreement.

On 31 July 2019, the Energy Commission appointed ECG as interim operator of electricity retail sale in the southern distribution zone under Licence No. EC/ESL/02-19-001, previously issued to PDS.[25] A 30-day investigation was also initiated during that period. Then, on 6 August 2019, the Government sent a delegation to Qatar, the source of the guarantee, and the United States, to assist with the investigations.[26]

It is reported that on 5 September 2019, portions of the report of the independent investigator, FIT Consulting, allegedly exonerating PDS, were leaked.[27] Government has indicated that an official report on the investigations would be provided.

Proposals for changes in laws or regulations

The Land Bill, 2018 which is currently before the Parliament of Ghana, proposes to "…revise and consolidate the laws on land, with the view to harmonising those laws to ensure sustainable land administration and management, effective land tenure and to provide for related matters". To that end, it proposes to repeal most of the major legislation relating to land including the Lands (Statutory Wayleaves) Act, 1963 (Act 186).

Significantly, the Bill proposes to do away with the right of user, as exists under the Lands (Statutory Wayleaves) Act, 1963 (Act 186), and provides for lands required in the public interest to be compulsorily acquired by the State. The Bill further requires that provision is made to the satisfaction of the Lands Commission for the payment of compensation and related costs of the acquisition in an escrow account prior to undertaking the acquisition. It introduces a statutory time frame of two years within which the process of compulsory acquisition must be completed, and the requisite compensation paid.

Under the Bill, a registered interest in land is made subject to the overriding interests of a right of way, right of entry, an electric supply line and dam erected, constructed or laid in pursuance or by virtue of a power conferred by an enactment. The right of way need not be registered to have such effect.

* * *

Endnotes

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27. https://www.ghanaweb.com/GhanaHomePage/NewsArchive/PDS-cleared-of-wrongdoing-778770.

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Greece

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Overview of the current energy mix, and the place in the market of different energy sources

Lignite has been the backbone of Greece's electricity system for many decades, covering the biggest part of the country's electricity needs. All lignite-powered plants have always been owned by the Public Power Corporation ("**PPC**"), while no private entity has so far undertaken control over a lignite-fired power plant in Greece. PPC's share in power production currently accounts for approximately 70% of the country's overall production (without taking into consideration the power generated from renewable energy sources, "**RES**"). Over the past 10 years, the share of lignite in meeting the country's electricity demand has significantly decreased. This decrease has been offset by a similar increase in the shares of RES and hydropower, as well as imports of electricity mainly from Bulgaria and Turkey.

Crude oil accounts for approximately half of the country's Total Primary Energy Supply ("**TPES**") and over half of the total final consumption ("**TFC**"). Crude oil production in Greece, currently derived from two producing fields in Northern Aegean Sea (Prinos) by a single oil producer, is insignificant compared to the domestic oil consumption.

Natural gas is becoming an increasingly important fuel in the Greek energy mix, rising to a share of 28% in power generation and 15% in TPES in 2016. The Greek natural gas demand is fully covered by imported natural gas, which is injected into the National Natural Gas Transmission System ("**NNGTS**"), either through entry points from Bulgaria and Turkey or through the LNG Facility on Revithoussa island. Upstream gas operations are almost non-existent, as production of natural gas is negligibly small compared to the total consumption.

Liquefied natural gas (LNG) has made a significant contribution in alleviating the serious energy crisis that occurred during December 2017 – January 2018, as well as preventing smaller-scale crises on multiple occasions. Generally, to the extent that LNG is cheaper than pipeline gas, it contributes to the reduction of the cost of electricity production from natural gas, a drop reflected in the wholesale price of electricity. At the same time, LNG provides flexibility and is a means of risk management for gas suppliers, allowing for smoother and more economical pricing for consumers. Overall, the country's natural gas needs are mostly covered by imported natural gas and LNG, primarily from Russia, while other large gas suppliers include Algeria and Turkey.

Decarbonisation of the national energy market has been declared a top priority under Law 3851/2010, transposing Directive 2009/28/EU, which set the target of increasing the share of RES in gross final energy consumption to 20%, and in gross energy consumption to 40% by 2020. Further, as part of its "Clean Energy for all Europeans" package, the European

Commission has adopted an update of the Renewable Energy Directive for the period 2021–2030 (RED II), raising the overall EU target for RES consumption by 2030 to 32% and an energy-efficiency target of at least 32.5%, with an upwards revision clause by 2023. Based on the latest Eurostat reports, the share of RES in 2017 reached 16.95% (as compared to 15.08% in 2016) of the overall energy production, approaching the target that the country had set for the end of the decade.

In terms of capacity, currently, operative RES projects account for approximately 5.5 GW, with the target to stretch to 13 GW by 2030 and more than 23 GW by 2050. Based on the monthly report published in December 2018 by the RES & Guarantees of Origin Operator ("**DAPEEP**"), the Greek power production from RES in 2018 was allocated as follows: (a) wind farms accounted for 45.6% of the installed capacity and 49.6% of the total power produced; (b) photovoltaic ("**PV**") parks accounted for 44.5% of the installed capacity and 31.5% of the total capacity produced; while (c) hydropower plants accounted for 4.35% of the installed capacity and 6.4% of the total power produced.

Although to date, generation of geothermal energy is very limited, following the enactment of a new all-inclusive legal framework through Law 4602/2019, Greece has expressly declared its intention to exploit its geothermal resources, and promote this new-born RES sector.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

A landmark development expected to completely transform the Greek energy market, was the establishment on 18 June 2018 of the Hellenic Energy Exchange S.A. ("**HEnEx**"). The new entity was founded through a spin-off from the electricity market branch of the Electricity Market Operator ("**LAGIE**") by virtue of Law 4512/2018. The new market is set to replace the existing model, where the Greek wholesale electricity market was a day-ahead market, organised as a centralised mandatory pool, operated by LAGIE.

In light of the above, Law 4512/2018 paved the way for the replacement of the mandatory pool model by a Day-Ahead Market, an Intra-Day Market, a Balancing Market and an Energy Derivatives Market. From the contribution of the aforementioned branch to the new-born company, it follows that LAGIE is no longer going to be the market operator, and the wholesale electricity market as a whole is now transferred to the HEnEx. In turn, LAGIE, comprising the remaining sectors, has been renamed DAPEEP (the RES & Guarantees of Origin Operator, as mentioned above), assuming the role of the operator of RES producers and guarantees of origin.

The HEnEx is currently only operating the Greek Day-Ahead Market based on the Electricity Market Operation Code (RAE Decision 56/2012 as more recently amended by RAE's Decision 542/30.05.2019), while working on the creation of the intra-day electricity market. Once the HEnEx becomes fully operative, both the Day-Ahead Market (where electricity will be traded for physical delivery within the subsequent 24 hours) and Intra-Day Markets (transactions for physical delivery of electricity within the same day in order to cover any failures to fulfil deliveries from orders that have been closed the previous 24 hours through the next day's purchase) will be operated in accordance with the newly introduced RAE's Decision 1116/13.11.2018 ("**Day-Ahead and Intra-day Market Regulation**" or the "**Energy Exchange Regulation**").

Another milestone in the electricity field is the conduct of mandatory capacity auctions, the so-called "NOME auctions" (*Nouvelle Organisation du Marché de l'Electricité*). These auctions, carried out by LAGIE, were introduced by Law 4389/2016, in an effort by the Greek Government to reduce PPC's retail electricity market dominance, aiming to cut down its share from approximately 95% (in 2015) to less than 50% by the end of 2019 (a target set by Law 4336/2015).

The annual capacity of PPC's generated electricity to be sold at the auctions has gradually increased (from 8% in 2016 to 13% in 2019). However, despite the broad participation of alternative suppliers in the NOME auctions, the benefits for the consumers derived from the NOME mechanism have been limited so far, due to the export of a significant quantity of the power acquired from PPC. This practice led to the issuance of RAE's Decision 148/24.1.2019, imposing export limit measures on the private wholesale suppliers for the power quantities acquired through the NOME auctions. The most recent NOME auctions, completed in April and July 2019, saw a dramatic increase in electricity prices, while RAE was again expected to set the bar high for the scheduled October 2019 auction.

After PPC's privileged access to the cheaper lignite was found by the European Commission to constitute a quasi-monopolistic right which allowed PPC to maintain its dominant position in the Greek wholesale electricity market, thus blocking the entry of new players in breach of the EU Treaties, 2018 saw the adoption of significant restructuring measures in this field through Law 4533/2018. Based on this recent law, PPC was forced to divest from its three biggest lignite-fired plants (in Meliti in northwestern Greece and Megalopolis in the country's south), with a combined installed capacity of 900 MW, selling the latter to private investors through an international public tender. Following an unsuccessful tender in February 2019, an extension to the country's commitment was granted allowing for a new tender under the same framework through Commission's Decision (C) 2019/2748. Another international tender carried out in July 2019 was declared null and void, as it attracted no bids that met the government's minimum standards.

A public tender was launched by the Hellenic Republic Asset Development Fund ("**HRADF**") for the acquisition of a majority stake (50.1%) in the Hellenic Petroleum S.A. ("**HELPE**"), a leading company in the Greek energy sector, with activity focusing on the supply, refining and trading of oil products, oil exploration and production. No binding offers were submitted in the tender, which took place in April 2019, for the acquisition of the majority stake currently held by the HRADF and the other strategic shareholder, PanEuropean Oil and Industrial Holdings S.A. and thus there was no positive outcome of the contemplated transaction. Subsequently, the HRADF was assigned with exploring all options available towards proceeding with the transaction, while the discussions between the Greek Government and the institutions are ongoing, aiming to determine the most proper model for HELPE's restructuring.

Following the substantial transformation of the hydrocarbons legal framework in 2011, new practices were introduced in the upstream oil sector, aiming to create a more appealing investment climate and to attract serious investments both domestic and foreign. Over the past few years, as part of its effort to secure additional revenues, the Greek Government, through the Hellenic Hydrocarbon Resources Management S.A. ("**HHRM**"), has entered into numerous lease agreements for the development of hydrocarbons at several offshore and onshore blocks (Aitoloakarnania, Ioannina, Arta-Preveza, North-West Peloponnese, Katakolo, Sea of Thrace, West Patraikos Gulf), while during the course of 2018–2019, the HHRM entered into significant lease agreements for the Ionian Sea, South West Crete and West Crete blocks. The lease agreements for: (a) South West Crete and West Crete, involving a consortium comprising Total, ExxonMobil and HELPE; and (b) the Ionian Sea involving

Repsol and HELPE and Block 10, west of the Peloponnese, for which HELPE is the sole holder, are pending Parliament's approval and are set to be ratified by law in the course of the next month.

The picture of the Greek wholesale natural gas market has also changed dramatically over the past couple of years. Until recently, the Public Gas Corporation ("**DEPA**") was the dominant player in the domestic natural gas market, holding a share of 96% or 42.7 million MWh in 2016. As of 2017, private companies entered the natural gas wholesale market dynamically, with imports of natural gas (including LNG) approaching 20–30% of the total transactions. The opening of the wholesale market, together with the expansion of the sources of LNG origin, are set to enhance competitiveness among gas suppliers.

More importantly, Law 4602/2019 provided for the split of DEPA's commercial and infrastructure activities. The shares of DEPA are currently held by the HRADF (65%) and HELPE (35%) but under the new provisions, DEPA would be divided into two separate legal entities: "DEPA Infrastructure S.A.", comprising all the distribution gas activities of DEPA, along with the international projects in which DEPA participates; and "DEPA Trade S.A.", where all DEPA's gas-related activities (both wholesale and retail) would be transferred. In turn, a stake of 50% plus one share of the share capital of DEPA Commercial S.A. would be sold to a private investor through a tender procedure carried out by the HRADF.

A game-changing development expected to allow Greece to receive larger LNG cargoes was the expansion and upgrading in 2018 of the Revithoussa LNG facility, the country's only operative LNG terminal, which is owned and operated by the National Natural Gas System Operator (DESFA) S.A ("**DESFA**"). The upgrading of its third tank increased the total storage capacity of the terminal by 75% to 225,000 m^3 from 130,000 m^3, facilitated growth of the gasification rate by 40% at 1,400 m^3 per hour from 1,000 m^3 per hour, and enabled the docking of larger LNG cargoes. Regarding the technical operation of the terminal, it is worth mentioning that in the first half of 2019, the average gasification increased to 80.99 million KWh per day, from 51.57 KWh in 2017 and 38.05 million KWh in 2018, respectively.

Another significant development in the natural gas field is the establishment of a virtual trading point operating at the National Natural Gas Transmission System ("**NNGTS**"), which became fully operative as of July 1st 2018. With the activation of the virtual trading point, natural gas traders not involved in physical trading are offered for the first time the possibility to operate in the Greek market, since it is now possible to enter into transactions, irrespective of whether or not they have contracted capacity at entry/exit points. This new operation was introduced by the newly amended NNGTS Operation Code (4th revision), aiming to further increase the liquidity of the Greek natural gas market in compliance with EU Regulation 459/2017 establishing a network code on capacity allocation mechanisms.

Since 2018, the country is undergoing an impressive increase in the share of renewables in the electricity generation, even over-achieving the targets set for solar energy. Following a deadlock in the previously implemented support schemes and after a period of stagnation between 2013 and 2018, the Greece RES market is nowadays booming, particularly as a result of a new state aid scheme introduced by Law 4414/2016, aiming to enhance RES investment and align the Greek energy market with the EU targets.

Under the RES state aid programme, set to run through 2018–2020, qualifying RES projects may be granted 20-year operating aid agreements in the form of feed-in-premiums ("**FiP**"), i.e. contracts-for-difference ("**CfDs**") between the market price of electricity and a fixed reference price, which is determined through competitive procedures conducted by the

Regulatory Authority for Energy ("**RAE**"), all in replacement of the previous unsuccessful feed-in-tariff ("**FiT**") system.

Following a pilot tender carried out in 2016, and the State Aid clearing of the new framework by the EU, the first two technology-specific capacity tenders were conducted in 2018, resulting in the gradual lowering of the average reference tariffs. The first joint competitive tender procedure (large PV and wind projects) was completed by RAE in April 2019, while separate tenders for PV and wind took place in July 2019.

Finally, the country's overall energy environment will be greatly impacted by the newly issued Law 4602/2019, providing for the unbundling of the natural gas distribution networks, as well as introducing a special legal framework regulating the exploration for and generation of geothermal energy.

Developments in government policy/strategy/approach

Directive (EU) 2009/72, as part of the Third Energy Package, first set the groundwork for the restructuring of the electricity market, aiming to establish access to the network for cross-border exchanges in electricity. This initial effort was further elaborated by subsequent Regulations (EU) 713/2009 and 714/2009, introducing the so-called EU Target Model, laying down the major target of the European electricity market integration.

A key component of the European Target Model, as set out in Regulation 2015/1222 ("**CACM Regulation**") is the concept of market coupling, which Greece is in the process of setting the ground for, in close cooperation with its neighbouring countries. This effort has started with the establishment of a radically new wholesale market model, aiming to enhance competition and remove significant distortions in the electricity market (see above regarding the establishment of the HEnEx). To this end, RAE has already embarked on the development of appropriate tools, methods and indicators for the monitoring of the four wholesale markets, once they become fully operative.

In light of the recent enactment of the "Clean Energy for all Europeans" package, the Greek energy market is on the verge of another fundamental make-over. More specifically, the adoption of the recast Electricity Directive (EU) 2019/944, the recast Renewable Energy Directive (EU) 2018/2001, the revised Energy Efficiency Directive (EU) 2018/2002, the new Electricity Regulation 2019/943, the Energy Performance of Buildings Directive 2018/844, as well as the Regulation on governance of the energy union and climate action (Regulation 2018/1999), the Regulation on risk-preparedness in the electricity sector (Regulation 2019/941) and the Regulation on a European Union Agency for the Cooperation of Energy Regulators (Regulation 2019/942) are expected to gradually transform the internal energy market towards a sustainable, low-carbon and environmentally friendly economy.

The new Government's strategic plan for streamlining and restructuring the retail electricity market, will start with the part-privatisation of the Hellenic Electricity Distribution Network Operator ("**DEDDIE**"), a 100% subsidiary of PPC. The distribution network, which currently belongs to PPC, will be transferred to DEDDIE before the part-privatisation process; that said, the partial sale of DEDDIE, which is the most profitable asset in PPC's portfolio, contributing significant amounts in its operating profits per year, is expected to attract considerable international interest.

Another item on the Government's agenda is the sale of a further stake in the Independent Power Transmission Operator IPTO ("**IPTO**"), an entity vested with the ownership and operation of the national power grid. The IPTO, originally established by virtue of Law

4001/2011 as a 100% subsidiary of PPC, was restructured in 2017 based on the Ownership Unbundling model, through the sale of 24% to a strategic investor and the transfer of 25% to a state owned SPV, with the Greek State indirectly retaining 51% of its shares. Currently, the new Government is contemplating the potential sale of the 51% stake directly and indirectly controlled by the Greek State through an open tender procedure.

Further, the new Government has foreshadowed that, as part of a restructuring plan for the PPC, the utility will complete its exit from lignite-fired generation. Following the two unsuccessful tenders for the sale of the Meliti and Megalopolis lignite-fired plants (please see above), divestment from lignite will be effected through the gradual shutdown of the two plants in consultation with the local communities; according to the proclaimed programme of the Ministry of Energy and Environment, the process is set to commence by the end of the first half of 2020.

Following the unsuccessful tender for the sale of a majority stake in HELPE which took place in April 2019, a follow-up sale effort offering a stake in HELPE will only involve the Greek State, holding a 35.48% share in the petroleum company. The new Government has made clear that the privatisation of HELPE is a top-priority sale, with the final decision on the proper way to move forward still lying ahead.

Although the NOME auctions were initially scheduled to take place by 2020, due to the bad financial situation of the utility and its poor performance over the year 2018, as well as in view of the upcoming replacement of the mandatory pool model by the new electricity market in line with the EU Target Model and entry into operation of the HEnEx, the Greek Government is now contemplating abolishing NOME auctions. Currently there is no certainty regarding whether any other equivalent mechanism will be implemented or whether producers and independent suppliers will merely interact through bilateral contracts within the framework of the organised market.

A shift has been also made by the recently elected Government with regard to the previous government's privatisation plan for gas utility DEPA. In this context, the split of DEPA's commercial and infrastructure activities, and the intended plan for the sale of a majority stake in the commercial part of DEPA, is expected to be overturned in the near future. Instead, currently the most likely scenario is the offering of majority stakes in both the utility's distribution network and trading interests.

In light of the international developments in the energy storage field and, in particular, the enhancement of the relevant technological applications and the falling costs of storage equipment, the Greek Government is expected to introduce a special legal framework regulating energy storage facilities. The HRADF is also due to launch a tender for the exploitation of a natural gas storage facility in South Kavala which, when operative, will improve the management of the natural gas suppliers' portfolio, thus enhancing security of supply in Greece. Launch of the tender is expected by the end of 2019 or early 2020.

As part of its broader effort to create a carbon-free community by 2050, the Greek Government is determined to enhance the RES market, particularly by streamlining the licensing process and reducing bureaucracy, as well as excluding large-scale RES projects from mandatory participation in capacity tenders. Further, the Government's short-term plans include the legislative grant of attractive tax incentives for the upgrading of the energy performance of buildings, aiming to accelerate the rate of building renovation towards more energy-efficient systems, and make new buildings 'smarter'.

With a view to boost the establishment of hybrid renewable energy systems in locations that are not fitted with an electricity distribution system, such as the non-interconnected islands, the new Government has pledged to introduce a special legal framework to govern hybrid power. The creation of a hybrid power market is expected to provide increased system efficiency as well as greater balance in energy supply, resolving the significant power outages on the Greek islands.

Developments in legislation or regulation

Law 4001/2011, transposing Directives 2009/72/EU and 2009/73/EU, is the main piece of legislation currently governing the operation of energy markets in the electricity and natural gas sectors in Greece, including the activities of the production, supply, purchase, transportation and distribution of natural gas and electricity. Its primary objective was the creation of a Single Internal Energy Market, in line with the EU secondary legislation; therefore, its provisions focus on the separation of transmission and distribution activities from generation and supply activities in the electricity and gas sectors. To this end, same law established a certification process for transmission system operators, and measures for the effective unbundling of the regulated transmission and distribution activities from the competitive production and supply activities.

As anticipated above, until recently, by virtue of Law 4001/2011, the Greek wholesale market model was organised on the basis of a regulated compulsory offer of electricity to a day-ahead market, leading to the centrally organised sale of electricity at a uniform price (System Marginal Price), which reflected the offer of the most expensive unit dispatched. Participants to the mandatory pool were, on the one hand, producers and importers of electricity and, on the other hand, suppliers and exporters of electricity. Imbalances (i.e. deviations from day-ahead schedules) were settled through a distinct mechanism, but there was no balancing market. Clearing of the day-ahead market was performed by the market operator LAGIE, while IPTO was responsible for conducting the real-time dispatch, clearing the imbalances as well as settling payments for ancillary services and several other charges. Since October 2015, LAGIE has also been competent to provide Registered Reporting Mechanism ("**RRM**") services to the energy market participants of Greece, according to Regulation ("**EU**") No 1227/2011 ("**REMIT**").

Law 4512/2018, in implementation of the CACM Regulation, introduced the new market model to be regulated by the HEnEx and comprising the electricity market, the energy financial market, the natural gas market and the environment market. As already mentioned above, the electricity market is divided into a Day-Ahead Market, an Intra-Day Market, a Balancing Market and an Energy Derivatives Market. Transactions involving energy financial means may be concluded bilaterally, while the day-ahead market will operate sales through physical delivery, including products purchased on the energy financial means market and other wholesale products sold through physical delivery. Producers will be obliged to offer products for the total of their capacity, to the extent such capacity is not booked at the energy financial market.

The balancing market will be operated by IPTO, which will be responsible to ensure compliance with Regulation 714/2009 and the Regulation on Wholesale Energy Markets Integrity and Transparency. The HEnEx will further establish a new company for clearing transactions performed on the day-ahead and intra-day markets. In order to operate the energy financial market, the HEnEx will cooperate with the Athens Stock Exchange, while the supervisory authority over the HEnEx will be shared between RAE and the Hellenic Capital Markets Commission.

The Greek RES market is primarily regulated by Law 3468/2006, which, among others, introduced the first state aid scheme based on a guaranteed FiT system (operating support based on a fixed compensation price), where producers received standard remuneration amounts and, consequently, minimising exposure to the market risk. Law 3468/2006 differentiated between various categories of RES producers and the amount of the remuneration varied depending on whether or not the plants were located in mainland Greece or on the islands, i.e. whether or not they were connected to the mainland grid.

The aforementioned RES support scheme was partially replaced by virtue of Law 4414/2016, which introduced the FiP scheme (operating support based on a differential compensation price). Based on the newly introduced support mechanism, RES and cogeneration ("**CHP**") plants participate in the electricity market and are awarded a sliding FiP and as of 2017, FiPs are granted through mandatory capacity auctions organised by RAE. However, exemptions apply to smaller plants, i.e. wind energy plants ≤3MW and other RES ≤500kW, which are eligible for a FiT.

Other incentives focusing on the increase of the penetration of renewable energy into the electricity supply mix and the reduction of production from conventional plants, include recent competitive procedures for the development of pilot RES projects at the Non-Interconnected islands, under an attractive operational support scheme (Article 151 of Law 4495/2017). Further, self-production from PV plants through net-metering was introduced in 2014 and is currently governed by Ministerial Decision 15084/382 (GG B' 759/05.03.2019). Law 4414/2016 (GG A' 149/9.8.2016), extended self-production to additional technologies, namely small wind turbines, biomass/biogas/bio liquid stations, small hydropower stations and cogeneration power plants.

As mentioned above, Law 4389/2016 introduced quarterly NOME auctions whereby PPC is obliged to sell the electricity term products through physical delivery to the alternative electricity suppliers. Based on Law 4389/2016, the NOME auctions mechanism works as follows: in its capacity as the dominant domestic player in lignite and hydropower production, PPC offers to independent producers cheaper access to these sources through electricity forward products acquired beyond the mandatory pool of the day-ahead wholesale electricity market. These auctions enable alternative suppliers to access cheaper electricity acquired beyond the mandatory pool, thus gaining a bigger market share as compared to PPC.

Law 2289/1995, transposing Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons, constitutes the main applicable legislation governing the development of hydrocarbons in Greece. This law was substantially amended by Law 4001/2011, through which new practices were adopted, aiming to create a more appealing investment climate and to attract serious investments in the oil sector.

Law 4513/2018 set the legal framework for the establishment of Energy Communities, aiming to promote social economy, solidarity and innovation in energy and energy sustainability, as well as to increase energy efficiency in final consumption in local communities. A number of financial incentives granted to Energy Communities aim to encourage development of RES and high-efficiency cogeneration of heat and power ("**HECHP**") plants. According to the new law, Energy Communities are incorporated as civil law partnerships by local individuals, public and private law legal entities and/or municipal/regional authorities. Further, Energy Communities may deal in the production, storage, self-consumption, sale of electricity or heating/cooling derived from RES or HECHP within the region of their registered seat. An Energy Community may also take up management of raw materials used in the production of electricity or heating/cooling from biomass, bio-waste, or biofuel, procurement of high-efficiency appliances, installations and electric, natural gas, LNG or biofuel-fuelled vehicles, as well as power and natural gas distribution and supply. While as a principle, Energy Communities are non-profit organisations, they may distribute profit to their members on certain conditions (to be incorporated by at least 15 members, or 10 in case of islands with population below 3,100 inhabitants, 50% of which are individuals).

Law 4602/2019 introduced a special legal framework for geothermal power and provided for the unbundling of the national distribution system, as well as the restructuring of DEPA (please see above).

The electricity-related legal framework is largely implemented through a number of regulations: the Electricity Market Operation Code (RAE Decision 56/2012, GG B 104/31.01.2012 as more recently amended by RAE's Decision 542/2019, GG B' 3.6.2019); the Power Transmission System Code (GG B' 103/31.1.2012, latest version no 3.6 published in April 2019); the Distribution Network Code (RAE' Decision No. 395/2016, GG B' 78/20.01.2017); the Non-Interconnected Islands Network Code (RAE's Decision No. 39/28.1.2014, GG B 304/11.2.2014, with a second version published in April 2018); the Power Supply Code (Ministerial Decision No. 29.3.2013, GG B 832/9.4.2013); and the Licensing Regulation for Electricity Supply and Trade (GG B' 2940/5.11.2012).

Likewise, the oil and gas industry is regulated, *inter alia*, by: the NNGTS Management Code (RAE's Decision 123/2018, GG B' 788/7.3.2019); the Distribution Network Code (RAE's Decision No. 298/2018, Government Gazette B' 1507/02.05.2018); the Natural Gas Licensing Regulation (Ministerial Decision 178065/17.08.2018, GG B' 3430/17.8.2018); the NNGS Users Registry Regulation (Ministerial Decision No. Δ1/Α/5816/2010, GG B' 451/2010); the Tariffs Regulation of NNGTS Basic Operation (GG B' 3720/20.10.2017, most recent version thereof approved by RAE's Decision 539/2019); and the Approval of NNGTS Usage Tariffs (GG B' 3513/01.11.2016); as well as the Oil Licensing Regulation (Ministerial Decision No. Δ2/16570/2005, GG B' 1306/2005).

The RES market is regulated by the Licensing Regulation for Electricity Production from RES (GG B' 2373/25.10.2011).

Further, as of July 2019, a draft Regulation on the Energy Derivatives Market has been opened to public consultation, pending voting by Parliament.

Judicial decisions, court judgments, results of public enquiries

The pivotal role of energy has been underlined in the recent case law of the Greek courts, which have linked the right to electricity supply to the fundamental principle of the protection of human dignity, as enshrined in Article 2 of the Greek Constitution. More precisely, the Council of State, through its decision No. 1972/2012, declared that cutting off the power supply to customers who fail to pay the special real estate tax built into the electricity bills (article 53 par. 11 of Law 4012/2011) deprives customers of a social good and violates human dignity, and is therefore unconstitutional.

The Greek electricity market suffered a heavy blow in 2012, when two electricity trading companies faced serious economic problems, as a result of which they were unable to repay the due amounts to the electricity producers, which amounted to more than €172,000,000. In response to this breakdown, through its decisions 851A/2012 and 243/2012, RAE revoked the trading licences of both power suppliers, with a view to secure supply of electricity to the end users and avoid further implications for the retail electricity market. The exit of two major players from the retail market caused a serious crisis in the national electricity market as a whole and forged the subsequent lack of trust towards independent energy suppliers, at the time posing an additional obstacle to the liberalisation progress of the energy sector.

Central to the dispute resolution mechanisms in the Greek energy sector has been RAE's arbitration ruling No. 1/2013. RAE's permanent arbitration mechanism was established by virtue of Article 37 of Law 4001/2011 as an alternative process for the resolution of disputes arising between persons operating in the energy sector. The above ruling was given on a dispute between Greece's biggest electricity producer and a trading company over the pricing terms, following failure of the parties to come to a mutually acceptable tariff agreement. RAE's permanent arbitration mechanism came under heavy criticism due to the delays in the process, as well as the impartiality problems that arose during the procedure. Since then, said mechanism has not been activated in any other case, while the Government's objective is to enhance its operation, transforming it into a business-friendly tool.

Finally, the clearing by the European Commission of the auction scheme for the FiP contracts introduced by Law 4412/2016 (as described above) has played a key role in the recent RES market boom. The EU Commission, through a decision issued in January 2018, found the support scheme to be in line with the EU State aid rules and, in particular, the 2014 Guidelines on State Aid for Environmental Protection and Energy. The Commission found that the support scheme would further EU energy and climate goals whilst preserving competition, resulting in a significant increase in the number of RES plants operating in Greece.

Major events or developments

In addition to the significant developments described in the section regarding changes in the energy situation in the last 12 months, the following major events are expected to make a substantial contribution to gradually enhance Greece's position as an energy hub:

The most significant private projects are the Trans Adriatic Pipeline AG ("**TAP**"), which will transport natural gas from the Shah Deniz II field in Azerbaijan to Europe, and the Gas Interconnector Greece-Bulgaria ("**IGB pipeline**"), which will provide a direct link between the national natural gas systems of Greece and Bulgaria, acting as a strategic gas transportation infrastructure and thereby enhancing supply security to Greece. While construction of the IGB Pipeline started in May 2019, construction of the TAP is approaching completion.

The Alexandroupolis FSRU, an LNG terminal, construction of which is due to start in 2020, will comprise an offshore floating unit for the reception, storage and re-gasification of LNG and a transmission system shipping natural gas into the NNGTS, thus securing new natural gas quantities for the supply of the Greek and the regional southeastern European markets. Gastrade, the project company, is currently halfway in its effort to be granted a third party access ("**TPA**") exception and a market test process is ongoing in cooperation with RAE. The FRSU project is being developed by the Copelouzos group in association with Gaslog, an international LNG carrier, while Greek gas utility DEPA, its Bulgarian peer Bulgartransgaz, as well as private investors, are also expected to acquire a stake in the project company. The Alexandroupolis FSRU, once completed, will be the second LNG terminal operating in Greece, together with the LNG terminal of Revithoussa island (the latter being part of the NNGTS).

Following their entry into operation, the IGB pipeline and the Alexandroupolis FSRU will be interconnected with the TAP, with all three facilities serving the transportation of Caspian gas to European markets.

Further, the East Med pipeline, one of the most important export projects for Eastern Mediterranean gas, a region at the epicentre of energy developments because of recent years' discoveries, is a 1,900km natural gas pipeline planned to cross the Israeli, Cypriot and Greek EEZ, reach Greece and from there connect to Otranto, Italy, through an underwater pipeline. The EastMed pipeline project is expected to improve Europe's energy security by diversifying its routes and sources and providing direct interconnection to the production fields. The project will also support the economic development of Greece and Cyprus by providing a stable market for gas exports.

Following the start of construction of the Crete-Peloponnese interconnection in 2018, the Crete-Athens electricity grid interconnection is urgently needed in order to prevent a looming energy shortage on Greece's largest island. Outdated diesel-fuelled power stations operating on the island need to be withdrawn to meet EU environmental regulations. Ariadne Interconnection, a special purpose vehicle established by the IPTO, assigned with the implementation of the Crete-Attica interconnection project, is currently in the process of selecting the private companies that will undertake construction of the electricity grid project, with a view to have the works completed in 2022.

In addition to the above infrastructure projects, the Greek energy market is also undergoing restructuring changes through the privatisations programme implemented by the HRADF. In anticipation of the outcome of the pipeline tenders mentioned above, 2018 saw the successful conclusion of a milestone tender for the part-privatisation of DESFA through the transfer of a 66% stake (31% owned by HRADF and 35% owned by HELPE) to SENFLUGA Energy Infrastructure Holdings S.A. for a total amount of €535 million.

Proposals for changes in laws or regulations

The attempted structural and institutional changes started with the establishment of the HEnEx took the electricity wholesale market one step further, aiming to ensure transparent and competitive prices, while at the same time, promoting fair and healthy competition, expected to encourage the entry of new market players. Undoubtedly, these significant reforms are ambitious improvements in line with the country's international commitments and the European trends. However, the effective realisation of these plans is a rather challenging task for both the Greek State and the market participants, especially at the beginning of the actual functioning of the wholesale market in its new form. To this effect, a number of regulations and codes have to be issued or amended in order for any regulatory gaps to be filled and the new market model to become fully operative.

The soaring congestion of pending licensing applications before governmental authorities is the biggest challenge faced by both domestic and foreign investors in the Greek energy market. Particularly in the RES sector, the Greek authorities face difficulties with providing the necessary licences and connecting assets to the country's national grid in time, while the pipeline of projects is growing rapidly. In order to facilitate access to energy investments, the Greek Government's immediate target should be the simplification and digitalisation of the licensing process, with the possibility for on-line submission of applications and online application status tracking.

Finally, a valuable tool for the heavily regulated energy market and a breakthrough for the field's professionals would undoubtedly be the codification of the legal framework, as well as the issuance of sector-specific guidelines in order to facilitate implementation of law and ultimately accommodate the rapidly growing financial interest.

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India

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Overview of the current energy mix, and the place in the market of different energy sources

India is globally ranked third in power generation, accounting for 5.86%, i.e. 1,561,100 GW of the world's total annual energy generation after China and the US; owing to India's geographical size, this transforms into massive capacity. The power deficit situation in the country has improved over the past few years; from 2014 to 2019, the energy deficit (shortfall in energy supply during a day) reduced from 3.6% to 0.6% and the peak deficit (shortfall in supply during highest consumption period in a day) reduced from 4.7% to 0.8% as at April 2019.

At the same time, India's share of total global primary energy demand is set to increase from 6% to 11% by 2040, backed by population growth and strong economic development. Over the past 12 months, the Indian power sector has undergone sea changes, with investments in the power sector growing at a record 12% (US$ 85bn), and the renewable energy sector offering investment opportunities of up to US$ 30bn every year for the next decade and beyond. This is largely due to 100% FDI being allowed in the renewable energy, electricity, power generation and distribution sectors, and also indicative of the fact that the policies of the past and present have been impactful in improving the status of India as a power consumer and a power generator.

In India, the total installed capacity matrix is almost equally distributed between the Government and private players, with the Government handling about 192,995 MW, constituting about 53.5%, and the private players handling the remainder of 167,462 MW, constituting 46.5% of India's total installed capacity, as of the beginning of August, 2019. Within the Government, Central Government has an installed capacity of 90,177 MW at 25.0%, and the State Government of 102,818 MW at 28.5%.

Buoyant with the rapid growth of renewable energy in India, the Government is aiming to add 225 GW of renewable energy capacity by 2022. The energy mix in the Indian scenario comprises largely thermal power, which includes coal, lignite, gas and diesel, while the spectrum of renewable energy includes hydro, biomass, urban & industrial waste power, solar and wind energy. Power generated from thermal resources accounts for about 63.2% at 227,644 MW, comprising coal at 195,810 MW (54.3%), lignite at 6,260 MW (1.7%), gas at 24,937 MW (6.9%) and diesel at 638 MW (0.2%). Power generation from hydro resources accounts for 45,399 MW (12.6%), nuclear utilities 6,780 MW (1.9%), and other combined at 80,633 MW (22%).

While conventional sources currently represent 63.2%, with the Government of India's ambitious projects and targets, power generated from Renewable Energy Sources (RES), currently standing at 34.6%, this is expected to very soon overtake the installed capacity power generated from conventional sources, despite the latter continuing to rise.

India presently has an installed capacity of nuclear utilities of 6,780 MW; the government has proposed a further increase in this capacity, by constructing 10 more heavy-water-type reactors, which will increase capacity to 13,480 MW by 2024–25. This will satisfy the ever-increasing needs of a power-demanding nation. The Government, through the National Power Corporation of India (NPCIL), is building one of the world's largest nuclear plants with a capacity of almost 10,000 MW, having six pressurised reactors of 1,650 MW each, at Jaitapura, Maharashtra with the help of Framatone, France which was advised by HSA Advocates, India.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

India has seen several positive changes in the last year which have pushed the country into being a power generation behemoth. Some of the key developments are discussed in the following paragraphs:

Renewable status for large hydro & ocean energy projects:

In line with being a leader in achieving the green targets set under the Paris Climate change Agreement, India is making swift and major strides to generate 40% of its electricity from RES by 2030. The Government of India (GOI), through the Cabinet Committee on Economic Affairs, in March 2019 approved large hydro power projects over 25 MW, and allowed energy produced using various forms of ocean energy such as tidal, wave and ocean thermal energy conversion, to be classified as renewable energy. Until the beginning of January 2019, India's hydro power installation stood at 45.4 GW, constituting 12.9% of the total energy mix. As per GOI estimates of January 2019, the potential for tidal energy production in India is 12,455 MW; wave energy is 40,000 MW; and ocean thermal energy conversion is 180,000 MW.

Incentives in E-mobility sector:

The Union Budget 2019–20 addressed the concern to create an ecosystem for e-mobility in India to reduce the dependence on oil, petrol and diesel, with the following measures for its ambition to switch to electric vehicles (EVs) from conventional internal combustion vehicles by 2030:

(i) income tax deduction of INR 150,000 (US$ 2,150) on interest paid on loans for purchase of EV;

(ii) customs duty exempted on certain parts of EVs; and

(iii) reduction of GST rate on purchase of EVs (12% to 5%) and on EV chargers (18% to 5%).

In 2013, the National Electric Mobility Mission Plan 2020 (NEMMP 2020) was established for manufacturing policies aimed at encouraging investments in the E-mobility sector.

International Solar Alliance (ISA):

Once open to solar resource-rich states lying fully or partially between the Tropic of Cancer and the Tropic of Capricorn, membership of the ISA may soon be open to all countries in the world who are members of the United Nations, since India moved a resolution on August 5, 2019 which is likely to be approved by the requisite majority of the current member countries. This move will put solar energy on the global agenda, with universal appeal for developing and deploying solar energy across the world.

The ISA was established in 2015 by India and France and is a global organisation which provides an exclusive platform for cooperation and interaction amongst the various stakeholders in the global community, especially the solar resource-rich countries. They also work in consonance with other multilateral organisations, so as to achieve the ultimate goal of promoting the use and generation of solar energy, which is envisioned to mobilise more than US$ 1,000bn into solar power by 2030.

Developments in government policy/strategy/approach

In order to address its dynamic energy market and in the interest of supportable energy generation, the GOI has devised the following policies and schemes:

One Nation, One Grid Scheme:

Introduced in the Union Budget 2019–20, the ongoing plan contemplates interlinking five regional Indian grids to operate on the same frequency. The scheme will be implemented by June 30, 2020 to enable the transfer of power from resource-centric to load-centric regions, ensuring power connectivity to all states at an affordable rate. The inter-regional transmission capacity is expected to increase to 118,050 MW by the end of the XIIIth All India Plan by the Central Electricity Authority (CEA) resulting in a dynamic market which, with adequate investment, can pave the way to trading power across various nations.

Amendments to bidding guidelines for wind power projects:

On July 25, 2019, amendments to the Guidelines for Tariff-Based Competitive Bidding Process for Procurement of Power from Grid Connected Wind Power Projects (of 2017) were carried out. The following are the salient features of the said amendments:

(i) The timeline for land acquisition for such projects has been increased from seven months to scheduled commissioning date, i.e. 18 months.

(ii) The window for revision of declared Capacity Utilisation Factor (CUF) of wind power projects has been increased to three years. The commercial operation date of the declared CUF may now be revised once within three years, rather than the earlier one year only.

(iii) The penalty for energy shortages equivalent to the minimum CUF has now been set at 50% of the power purchase agreement (PPA) tariff for energy shortages that the Wind Power Generator is responsible to pay to the Procurer.

(iv) The commissioning schedule of wind power projects has been defined as 18 months from the date of execution of the PPA or PSA, whichever is later.

Constitution of Dispute Resolution Committee:

In June, 2019, a significant choice to promote solar and wind energy projects, the Union Minister of State for Power and New & Renewable Energy (IC) and Skill Development & Entrepreneurship, endorsed a proposition to set up a Dispute Resolution Committee to consider unforeseen conflicts between solar/wind power developers and the Solar Energy Corporation of India (SECI) and National Thermal Power Corporation of India (NTPC) beyond contractual matters. Such conflicts were considered and a transparent, unbiased dispute-resolution mechanism, composed of an autonomous, transparent and unbiased Dispute Resolution Committee (DRC), was set up.

Expecting disputes being dealt with by the DRC to involve a multitude of parties and be of complex nature, in order to work efficiently, the DRC was constituted of three members. The DRC would work as an appellate body to SECI and also have jurisdiction to decide over projects approved by SECI/NTPC.

State Rooftop Solar Attractiveness Index (SARAL):

Launched in August 2019 during the Review Planning and Monitoring (RPM) meeting with states and State Power Utilities, SARAL has been designed collaboratively by the Ministry of New and Renewable Energy (MNRE), Shakti Sustainable Energy Foundation (SSEF), Associated Chambers of Commerce and Industry of India (ASSOCHAM) and Ernst & Young (EY). The rooftop solar deployment will make power sector sustainable and viable (as the cost of solar energy is reducing) and will help to ensure 24/7 power supply to all consumers. SARAL currently focuses on five aspects:

(i) robustness of the policy framework;
(ii) implementation environment;
(iii) investment climate;
(iv) consumer experience; and
(v) business ecosystem.

SARAL has a target to extract 40 GW solar energy from rooftop systems. A self-sustainable and private sector-driven rooftop solar sector holds the key for the renewable energy revolution in India. This project will create an alternative source of electricity to the companies for residential areas, but the main benefit of this is to the environment, since it reduces the dependence on fossil-fuel-generated electricity.

Safeguard Duty (SGD) on solar panels:

SGD is an import levy, over and above existing duties, which was imposed to check a sharp increase in the import of certain items that demotivated domestic manufacturing, causing disruption. The Energy and Resources Institute (TERI) in August 2018 asserted that increasing SGD would raise tariffs of future solar projects in India, which would impact the competitiveness of the solar power sector and also likely result in higher Average Power Purchase Cost (APPC) for the buying utilities, and higher costs to consumers.

Aiming to promote the domestic production of solar cells, either assembled or in panels, and in the pursuit of the same, on July 30, 2018 the GOI imposed SGD on import of solar cells. The rates payable on any solar cell imported from July 30, 2018 to July 29, 2020 are as follows:

(i) 25% *ad valorem* minus anti-dumping duty from July 30, 2018 to July 29, 2019 which is lapsed now, and from now onwards 20% of duty will be levied as specified below;
(ii) 20% *ad valorem* minus anti-dumping duty from July 30, 2019 to January 29, 2020 (inclusive); and
(iii) 15% *ad valorem* minus anti-dumping duty from January 30, 2020 to July 29, 2020 (inclusive).

This duty was imposed owing to the large-scale import of solar cells from China and as a measure to promote indigenous production, as more than 90% of solar panels and modules used in Indian solar projects come from China and Malaysia, and this levy is intended to protect domestic solar panel production from impacts due to increased imports. However, certain exemptions from this duty can be notified by the Government when the import is taking place from a developing nation.

National Wind Hybrid Policy:

With the aim of introducing a new area of availability for renewable power at competitive prices along with reduced variability, MNRE adopted the National Wind-Solar Hybrid Policy in May, 2018 which provides a framework for the promotion of large-grid-connected wind-solar PV hybrid systems for the optimal and efficient utilisation of land and transmission infrastructure. A scheme for new hybrid projects under the policy is also expected shortly.

The National Wind-Solar Hybrid Policy also aims to encourage new technologies, methods and solutions involving combined operation of wind and solar PV plants, procurement of power from a hybrid project in a tariff-based, transparent bidding process, and provide all fiscal and financial incentives to hybrid projects.

Developments in legislation or regulation

GOI has taken various initiatives by way of formulating policies and regulations to improve energy efficiency and promote sustainable development. The following are some of the key developments made in the legislation that have had a major impact on the power sector:

Amendments to the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects

In January 2019, the MOP issued the Amendment to the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects to reduce risk, enhance transparency and increase the affordability of solar power. The specific objectives of these guidelines, *inter alia*, are: to promote competitive procurement of electricity from solar energy by distribution licensees; to provide flexibility to sellers in internal operations while ensuring power security and tariffs for buyers; and to enhance standardisation and reduce ambiguity – and hence time – for the realisation of projects, to further ensure bankability.

The move is likely to help protect consumer interests through affordable power. It also aims to: provide standardisation and uniformity in processes, and a risk-sharing framework between various stakeholders involved in the solar PV power procurement; reduce off-taker risk and encourage investment; and enhance the bankability of projects and improve profitability for investors. It also provides for a change in law provision to provide clarity and certainty to generators, procurers, and investors/lenders.

Flue Gas Desulphurization (FGD) norm declared as Change in Law event

The Central Electricity Regulatory Commission (CERC) has declared that the Ministry of Environment, Forest and Climate Change, GOI (MOEF) Notification dated December 7, 2015 (thereafter revised on December 7, 2017), which mandates the installation of Flue Gas Desulphurization systems in thermal plants within two years from the notification, is a Change in Law event under the terms of the PPA. The CERC further directed thermal power plants to approach the CEA and have their technical consultancy report for the implementation of the amended norms approved. Thermal power generators were thereafter directed to conduct a competitive bidding process and award contracts to carry out the works required, in order to implement the amended norms, and incur the cost, and again approach the Regulator for the approval of the same.

MOEF directed the installation of FGD systems for meeting the emission limits for Sulphur Dioxide, and Selective Catalytic Reduction/Selective Non-Catalytic Reduction Technology in order to meet the revised limits for Nitrogen Oxide. Due to glitches in the previous implementation procedure, the Central Pollution Control Board provided specific timelines to thermal plants for the installation of the FGD system. As per the new timeline, amended norms are to be implemented between the period starting from 2020 to 2023.

Renewable energy push in Government's Smart Cities Mission

At the beginning of FY 2018–19, Diu Smart City was declared as a solar energy success story in the Government's Smart Cities Mission. Equipped with a 9 MW solar park spread over 50 hectares, and 79 government buildings with installed solar panels, Diu became the first city in India to run on 100% renewable energy during daytime. Other cities include Jaipur, at third in the list of world's top 10 smart renewable cities, and Bengaluru coming in at the sixth spot, as reported by Deloitte in 'Global Renewable Energy Trends'.

These were results of the GOI's 'Smart Cities Mission' program launched in 2015, carrying the objective of promoting cities that provide core infrastructure and decent quality of life to its citizens, a clean and sustainable environment, and application of 'smart' solutions. Such programs seek urban 'smart energy' solutions characterised by low carbon emissions and energy resilience.

Energy Conservation Building Code

Notified in January 2018, the National Electricity Plan (NEP 2018) has seen extensive implementation during FY 2018–19, and emphasises conservation and energy-efficiency. To promote the objectives of the NEP 2018, GOI launched the ECO Niwas Samhita, i.e. the Energy Conservation Building Code for Residential Buildings (ECBC–R), in December 2018. The implementation of this code is likely to further boost energy efficiency in the ever-growing residential sector and create more demand for renewable energy-generation sources, while aligning with the goal of environment conservation.

The plan takes into consideration the need to address the issue of climate change, and accordingly envisages the usage of coal for electricity generation, only to the extent India cannot procure power from its many zero-emission alternatives. As per the NEP 2018, the share of electricity generated from coal-based power plants is likely to be 64% at the end of 2021–22. Its share is projected to further come down to 58% by 2026–27 from the current level of 72%.

Judicial decisions, court judgments, results of public enquiries

Gujarat Urja Vikas Nigam Limited v. Adani Power (Mundra) Limited (CERC 2019);[1] *Energy Watchdog v. Central Electricity Regulatory Commission (SC 2017)*[2]

These two judgments, read together, played a significant role in unveiling the largest ever rehabilitations/restructuring of infrastructure assets in India's history, involving three thermal power generating plants of aggregate 10,000 MW generating capacity, representing a total capital investment of over US$ 10bn.

In *Energy Watchdog v. Central Electricity Regulatory Commission*, the Supreme Court had held that a change in the Indonesian legal regime dealing with the price of coal cannot be construed either as a *force majeure* event or as a Change in Law event under the contractual provisions of the relevant PPAs. Predictably, this led to severe cash flow mismatches with the generators, making their continued operations financially unviable. In furtherance to which, the Government of Gujarat (GOG) took a decision to rehabilitate these assets in the wider public interest. As part of such process, the GOG constituted a High Power Committee (HPC) comprising: Justice R.K. Agrawal, former Judge, Supreme Court; Mr. S.S. Mundra, former Deputy Governor, RBI; Dr. Pramod Deo, Former Chairman, CERC; and Hemant Sahai, Founding Partner, HSA Advocates, inducted to provide legal and strategic advice to the HPC. The financial and commercial restructuring was recommended to be incorporated by amending the PPAs and including the same as revised contractual provisions of the PPAs and ultimately approved by the appropriate commission.

To avoid any conflict of the recommendations with the Energy Watchdog judgment, an application was filed in the Supreme Court to get an in-principle ratification, whereby the

Supreme Court allowed the generators to approach the CERC for approval of the amendments to the PPAs.[3] Pursuant to this, the necessary petitions were filed with the appropriate electricity regulatory commissions. The first petition, being *Gujarat Urja Vikas Nigam Limited v. Adani Power (Mundra) Limited*, in respect of one of the projects of 2,000 MW, was filed before the CERC on the issue, *inter alia*, of the validity of proposed amendments in PPA being in the public interest. The CERC held that the GOG had taken a policy decision through a package deal to rehabilitate imported coal-based, stressed power projects located in the state in the wider public interest. Therefore, various provisions of the Supplemental PPAs should be perceived and considered.

This rehabilitation and financial re-structuring, under a policy framework, has no precedent in India and therefore is unique in its construct and implementation.

Dharani Sugars and Chemicals Ltd v. Union of India and Others[4]

The Supreme Court in this landmark judgment struck down the controversial circular issued by the Reserve Bank of India on February 12, 2018 (RBI Circular) which directed banks to initiate insolvency proceedings against companies having bad debts of INR 2,000 crores (US$ 280m) or above within 180 days, failing which the corporate debtor would have to be taken to the National Company Law Tribunal for insolvency action.

The RBI Circular was challenged as *ultra vires* Section 35AA of the Banking Regulation Act, 1949 as Section 35AA does not empower the RBI to issue generic directions for reference to the IBC without considering specific defaults. It was held that the RBI Circular was issued without the authorisation of Central Government and without any directions in respect to 'specific' defaults by 'specific' debtors as required under Section 35AA. However, the *Dharani Sugars* judgment does not hinder the RBI's powers to come up with a resolution framework for stressed assets – except that the RBI cannot give a direction for mandatory reference to the IBC in respect of debtors generally.

The Supreme Court ruling provides flexibility to banks for pre-insolvency restructurings. The banks and promoters of defaulting companies may welcome the flexibility to enter into consensual restructuring schemes while the availability of a lengthier window may also help achieve complex restructuring transactions in more realistic timetables (without the pressure of time periods set out in the RBI Circular).

Major events or developments

The source of power for issuance of the RBI Circular dated 12.02.2018 has been stated to be Section 35A of the Banking Regulation Act, 1949 read with the Central Government's circular dated 05.05.2017, Sections 35AA and 35AB of the said Act, and Section 45L of the Reserve Bank of India Act, 1934. The Supreme Court in the Dharani Sugars judgment held that a cursory reading of Section 35A and Section 35AA makes it clear that there is nothing in the aforesaid provisions which would indicate that the power of the RBI to give directions, when it comes to the Insolvency Code, cannot be so given.

Though the petition before the Supreme Court was principally filed by the power-producing companies, the judgment is applicable across all sectors. However, the said RBI circular mainly affected the power sector, because the said circular would have made the recovery of already stressed power companies even more difficult. The power plants are already suffering from issues relating to cash flows, credit rating, interest servicing, and simply applying the RBI guidelines mechanically by the banks, financial institutions, joint lender forums would have pushed these plants further into trouble without any hope of recovery.

This RBI Circular was estimated to have incurred a total debt due of INR 3.8 lakh crore (US$ 53bn) across 70 large borrowers, the majority of which were in the power sector. Considering the submissions of the Petitioners, the Supreme Court declared that the RBI Circular is *ultra vires* of Section 35AA of the Banking Regulation Act, 1949, limiting the power of RBI to proceed against stressed accounts and giving further major relief to the power sector. Pursuant to the aforesaid judgment, the Reserve Bank of India came up with the revised guideline by issuing the Reserve Bank of India (Prudential Framework for Resolution of Stressed Assets) Directions, 2019, providing for a framework for early recognition, reporting and time-bound resolution of stressed assets.

Proposals for changes in laws or regulations

Draft Amendments to Electricity Act, 2003

The Draft Amendments to the Electricity Act, 2003 were issued in September, 2018 which sought to increase competition in the sector by segregating the distribution segment into distribution and supply, rationalising tariff determination and promoting renewable energy. The salient features were as follows:

(i) Competition in supply segment: The amendment intends to bring in the concept of separate content and carriage licensees, by introducing a separate distribution licence for maintaining the distribution network, and a supply licence for the supply of electricity. The two new licensees will be obligated to supply 24/7 power to their consumers. Further, all sale or purchase of power to meet the annual average demand of power of an area will be done through long/medium/short-term PPAs. Permitting short-term trading may help supply licensees fill the unanticipated demand. Short-term trading may also help supply companies sell any surplus power resulting from lower-than-anticipated demand.

(ii) Power subsidies: Any subsidy to any category of consumer will be provided by the state or central government through Direct Benefit Transfer (DBT) to the bank account of the beneficiary. Cross subsidisation within a distribution area will not exceed 20% and will be progressively reduced and eliminated within three years. CERC/SERC will have to ensure that the reduction in cross subsidy is not less than 6% in a year.

(iii) Renewable energy: The proposed amendments define RES to include hydro, wind, solar, bio-mass, bio-fuel, waste including municipal and solid waste, geo-thermal, tidal, co-generation from these sources, and other sources as notified by the central government. The maximum capacity for a hydro plant to be classified as renewable will be notified by the central government. It also included changes to the definition of Renewable Purchase and Generation Obligation.

In summary, removal of the cross-subsidy may have two consequences: it could increase tariffs for currently low-paying consumers (agricultural and residential) who are being subsidised; or the state or central government may choose to alleviate any increase in their tariffs by giving them explicit subsidies through DBT. This will be helpful as, presently, the real benefit of subsidies provided by governments is not reflected, either because governments do not release subsidies in time or else they adjust them towards the dues of distribution companies (DISCOMs).

Dam Safety Bill, 2019

In March 2019, large hydropower projects were given a 'renewable energy source' status in India. Previously, only hydropower projects less than 25 MWs were considered as renewable energy projects. The measures announced by the GOI to promote hydropower sector are expected to bolster India's renewable power programme, as dam safety is a critical part of the hydropower programme and now receives top priority.

In August 2019, the Dam Safety Bill was passed by the Lok Sabha, seeking to set up an institutional mechanism for the surveillance, inspection, operation and maintenance of specified dams across the country. It is proposed to apply the provisions of the Bill to all specified dams in the country which have a height of more than 15 metres, or between 10 metres and 15 metres. Among other things, the Bill also seeks to resolve inter-state issues concerning the maintenance and safety of dams. The Bill enables the setting up of a National Committee on Dam Safety to formulate policies and regulations regarding dam safety standards, and to analyse the causes of major dam failures to suggest changes in safety practices. To implement these policies, the Dam Safety Authority is expected be set up at national and state levels.

Amendments to Tariff Policy, 2018

Amendments to the Tariff Policy were proposed in May, 2018 which include amendments in provisions related to the generation, transmission and distribution of electricity. The focus is to: make 24/7 uninterrupted power supply to all consumers; improve efficiency in the operation of distribution business; and address certain constraints faced in implementing change-in-law provisions, issues of open access, compliance and related aspects, and issues of tariff design, including the simplification of tariff categories and rationalisation of retail tariffs.

Draft Distribution Perspective Plan, 2019

In July 2019, the CEA prepared India's first-ever Draft Distribution Perspective Plan under the guidance of the Ministry of Power (MOP). Once released, the Plan would be operationalised along with the states and their DISCOMs, in a spirit of co-operative and competitive federalism. The Plan emphasises 100% metering of all consumers, and providing an electricity connection on demand. It also envisages frontier technology initiatives, and the conversion of all electricity consumer meters into smart meters in prepaid mode. The idea behind the same is to empower consumers with tools to help them conserve energy and plan their electricity usage in an efficient and optimal manner. The Plan anticipates increases in: distribution substation capacity (38%); distribution transformation capacity (32%) and types of feeder lengths (27–38%) by 2022.

Draft Electricity (Amendment) Rules, 2018

The Draft Electricity (Amendment) Rules 2018 (Draft Rules, 2018) propose various changes with respect to Captive Generating Plants (CGPs). CGPs are those power plants wherein not less than 26% of the ownership is held by captive users, and at least 51% of the aggregate electricity generated in such plant, determined on an annual basis, is consumed for captive use. The Indian electricity law regime provides statutory benefits to captive generators. Most importantly, it gives captive generators the right to open access, and exemption from open access cross-subsidy surcharge.

The existing Electricity Rules, 2005 required clarity in terms of the structuring and consumption requirements of a CGP. For instance, the Draft Rules, 2018 clarify that for the purpose of assessing the status of a power plant as CGP, a normative debt: equity ratio of 70:30 will be considered, wherein at least 26% of the equity base of 30% of capital employed, in the form of equity share capital with voting rights (excluding equity share capital with differential voting rights), needs to be invested by captive users.

Endnotes

1. Petition No. 374/MP/2018 passed on 12 April 2019 by CERC.
2. (2017) 14 SCC 80.
3. Order passed in *Energy Watchdog & Ors. v. Central Electricity Regulatory Commission & Ors,* Misc. Application No. 2705-2706 of 2018 in CA No. 5399-5400 of 2016 dated 29 October 2018.
4. The citation of the judgment is (2019) 5 SCC 480; dated 02 April, 2019 passed in Transferred Case (Civil) No. 66 of 2018 in Transfer Petition (Civil) No. 1399 of 2018.

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Overview of the current energy mix, and the place in the market of different energy sources

The Irish energy mix in 2018 could fairly be described as business as usual; characterised by slow, incremental progress towards renewables but sustained heavy reliance on fossil fuels. This orthodoxy has, however, been punctuated by a few key events; most notably a new government climate action plan, which aims to transform the energy sector in response to international and regional obligations as well as growing domestic pressure.

In 2017, Ireland's overall primary energy consumption saw an increase of 0.5% to 14,473 ktoe, a consequence of increased economic growth and a rising demand for energy in industry. The composition of energy use in Ireland improved slightly, however. Demand for fossil fuels dropped by 1.6% to now represent 90% of total energy consumption (coal 7.6%, peat 4.8%, oil 48%, natural gas 29.8%); while use of renewables increased by 19%. Renewables thus represented 9.3% of total energy consumption in 2017 (hydro 0.4%, wind 4.4%, biomass 2.6%, other renewables 1.9%).

Wind-generated energy remains the second-greatest source of energy and accounted for 25.2% of (normalised) electricity generation, an increase of 2.9% on the previous year, undoubtedly aided by the installation 532 MW of wind generation capacity. The Republic of Ireland has an installed capacity of 2,878 MW, and there is an all-island capacity of 3,916 MW. In December 2018, maximum output reached 3,990 MW on the island.

The contribution of renewables to gross final consumption was 10.6%, an increase of 1.1% on the previous year, moving towards the 2020 target of 16%. This pivot towards renewables substituted fossil fuel imports to the value of €278m. The amount of renewable electricity generated increased to 30.1% of (normalised) gross energy consumption, with the aim of arriving at 40% by 2020.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Brexit

The exit of the United Kingdom from the EU remains a pressing issue by reason of its timing and its potential disruptive effect, at least in theory, on assets and activities that span the UK–EU border such as the Integrated Single Electricity Market (I-SEM). How exactly Brexit will manifest remains to be seen, thus any statement as to its effect on industry is speculative. As the matter stands currently, Britain is due to leave the EU on October 31st.

The latest draft withdrawal agreement contemplates the continued application, in Northern

Ireland, of EU energy law, and the preservation of the SEM. If Brexit is not governed by such an agreement (a "no deal Brexit"), these consequences remain uncertain, although the European Commission (through D-G Energy) issued a notice to stakeholders in April 2018 that stated that:

> *"[as] of the withdrawal date, United Kingdom based operators will cease to participate in the single allocation platform for forward interconnection capacity, the European balancing platforms and the single day-ahead and intraday coupling."*

Ireland's energy markets are closely connected to those in the UK and to date, the regulatory regimes in both countries have worked well together. This is largely because a significant amount of the applicable energy regulation, in both the UK and Ireland, derives ultimately from EU legislation. Brexit may not change this immediately, but over time we may see the regulatory regimes diverging, with implications for our energy markets.

Energy and infrastructure connections between Ireland and the UK, especially Northern Ireland and Wales, may be affected by Brexit, in particular because:

(i) the electricity generated and consumed in Ireland and Northern Ireland passes through a common wholesale electricity market, the Integrated Single Electricity Market;

(ii) a 500MW sub-sea electricity interconnector has been built between Ireland and Wales – Ireland's only interconnection, and its means of accessing European electricity markets;

(iii) EirGrid, the transmission system operator on the island of Ireland, is planning to build a 400MW cross-border transmission line across the border between Ireland and Northern Ireland, to supplement the small number of lower-voltage power lines that already cross the border; and

(iv) much of Ireland's natural gas is imported through two sub-sea pipelines running from Scotland, while a "South-North pipeline" runs from Gormanston, Co. Meath, to Belfast.

Brexit, of itself, may not have an immediate impact upon the continued smooth operation of these energy markets and assets. Nor should Brexit disturb the extent to which the Irish elements of these arrangements continue to comply with European law. In the short term, the effects of Brexit will be felt most acutely in the context of the I-SEM discussed below.

The latest guidance from the CRU and the SEM Committee (issued in March 2019) states that in the event of a 'no-deal' Brexit, both the trade of electricity within the SEM, and the trade of electricity between Ireland and Great Britain across the East-West Interconnector (EWIC), will continue. However, the trade in electricity with Great Britain "may be less efficient, as some platforms operated under EU rules may not be used in the same way as today". This echoes the EU's guidance that UK operators will cease to participate in market coupling. The CRU and the SEM Committee maintain that while Great Britain will no longer participate in European day-ahead market coupling, "[trade] with Great Britain will continue, unaffected, in the intraday markets".

These statements are clearly only intended as high-level indications of the regulatory structure that is anticipated post-Brexit. Subsequent, more detailed regulatory and legal instruments will be required before a clear position is established.

It is to be hoped that the Brexit negotiation process delivers clarity as to the potential impact on this sector; however, at the time of writing, the regulatory consequences of this event for the Irish energy sector have not been settled. However, Brexit has, and will continue, to emphasise the importance to Ireland of energy self-sufficiency and interconnection with Continental Europe.

The Celtic Interconnector

In May 2019, EirGrid and its French equivalent *Réseau de Transport d'Electricité* (RTE) applied for European Commission funding for the Celtic Interconnector under Connecting Europe Facility (CEF) Energy Programme.

The proposed €1bn sub-sea Celtic Interconnector project would provide Ireland with a direct electricity link to Continental Europe. It is identified as a 'crucial project' in the context of climate action and energy security, especially given Ireland's only existing interconnection is with Great Britain. Currently EirGrid is considering landfall locations and converter station location zones in East Cork. Contemporaneously, the project is undergoing stakeholder consultation as part of its Investment Request to the Commission for Regulation of Utilities.

The Celtic Interconnector is featured in the Climate Action Plan and Project Ireland 2040. It is a Project of Common Interest (CPI) in the EU and therefore enjoys improved regulations and access to financial support. 2018/2019 saw strong practical advancements in the project and its important position within the decarbonisation objectives, both domestically and at a European level, will hopefully see this progress continue.

Developments in government policy/strategy/approach

Ireland 2040

2018 saw the announcement of Ireland 2040, the Irish State's much-needed infrastructure investment plan which guides public and private investment and aims to accomplish 10 strategic outcomes.

Project Ireland 2040 comprises two plans: the National Planning Framework (the "NPF") and the National Development Plan (the "NDP"). The latter is a 10-year, €115bn programme of social and economic investment aligned with National Strategic Outcomes (NSO). Two such objectives are: 'The Transition to a Low Carbon and Climate Resilient Society'; and the 'Sustainable Management of Water, Waste and Other Environmental Resources', the former being the single largest investment priority under Ireland 2040.

The NDP depicts a situation where climate objectives directly inform every policy pursued by every government department; where there is a close inter-departmental alignment of strategies and a system of mutual reinforcement through complementary tax regimes and regulatory measures. The national policy asserts the national objective of transitioning to a competitive, low-carbon, climate-resilient and environmentally sustainable economy by 2050. This, in effect, requires an aggregate reduction in CO_2 emissions of 80% compared to 1990 levels by 2050 across the electricity generation, built environment and transport sectors, and a solution for carbon neutrality in the land use sector.

The National Planning Framework provides broad strategies by which to pursue these targets, including the support of the bio and circular economies, efficiency in land management, and the incorporation of climate action targets into the planning system.

The NDP highlights the proposed Celtic Interconnector as a potential means of facilitating the growth of renewable energy. The Interconnector would be a sub-sea electricity cable linking Ireland and France at an estimated cost of €1bn. The capacity of the Celtic Interconnector is estimated at approximately 700 megawatts, capable of powering 450,000 households. The plan also referenced the need to de-risk and encourage private investment in Ireland's natural resources; it points to increased geological understanding following the completion of the Tellus and INFOMAR mapping programmes by 2028 as a way of derisking investment in natural resources. It also references €8.5bn to be invested by Irish Water in order to deliver efficient and robust infrastructure and services.

Climate Action Plan

The measures pertaining to the energy sector in the National Development Plan are substantively restated in the Climate Action Plan (built environment, transport, agriculture, forestry).

In June 2019, the Irish government revealed the Climate Action Plan to Tackle Climate Breakdown (the Plan), a document of 183 articles which purports to be a roadmap to Ireland's 2030 and 2040 targets, under the EU Effort Sharing Regulation and Ireland 2040 Plan, respectively. The Plan engages all government departments and inserts itself into all future government initiatives, requiring, for example, all government memoranda and policies to be examined for consistency with the Action Plan. It describes a situation in which the aims and principles contained in the Plan will permeate all upcoming legislations and policy – exactly how and if this will manifest, we do not know.

The Climate Action Plan is perhaps a misnomer, as while replete with ambitious targets, in many areas the 'plan' lacks prescriptive means of achieving them, or simply applies existing initiatives to new, loftier goals. However, the Climate Action Plan sets out ambitious objectives while acknowledging the inadequacies of the existing legislative and regulatory framework in tackling climate change in Ireland, and it establishes a roadmap for Ireland with specific timelines and milestones identified.

The Climate Action Plan also enjoys political cross-party support and should be seen as a statement of common intention and aspiration from which all future policies will flow.

Governance:

One of the more robust aspects of the Plan is the system of governance it establishes. It creates a system of accountability, oversight, on-going evaluation and mechanisms for review, adjustment and reform. This governance structure will be formally legislated through the Climate Action Act, for which the preceding Bill is currently being drafted. The Action Plan is envisioned as dynamic, evolving to lessons learned in the delivery of strategic objectives and refining strategies accordingly; in fact, flexibility to accommodate novel circumstances will be prescribed in the Climate Action Bill. An annual project report will detail progress made, challenges encountered and government responses.

As here illustrated, there is a quite severe system of accountability operating vertically and horizontally. Most actors in the system are being monitored by another. There seems to be an emphasis on transparency, with frequency of updates and progress reports mandated, and an invocation of more technical expertise. While, as we will see, the measures proffered within the Plan to achieve targets in certain domains are somewhat anaemic, this scheme of continuous oversight, accountability and review may force progress and effectuate a real change to the energy landscape.

Governing and oversight bodies:

1. The Climate Action Delivery Board was established within the Office of An Taoiseach, and assumes the primary role of holding public bodies and government departments to account in the performance of their roles and obligations under the Plan, and coordinating departmental efforts. The Board is required to present a delivery report to the Cabinet Committee and the Cabinet, which will be published on a quarterly basis. Similarly, a progress report will be presented to the Cabinet Committee and the Cabinet, and published each year.

2. The Climate Action Council has an advisory and oversight role. As the successor to the Climate Change Advisory Council, it will continue the latter's mission in assessing Ireland's progress towards a low-carbon economy, and critique and inform development. The Climate Action Council is empowered with further competencies, significantly recommending five-year Carbon Budgets to government, and providing policy evaluation based on the best available science.
3. The Plan recommends the establishment of a Standing Committee in Both Houses of the Oireachtas, which will have the function of holding members to account in the performance of their obligations within the remit of the Plan. They will be supported in this role by the Climate Action Office (also to be established), its assistance will take the form of furnishing evidence as to the effectiveness of policies pursued, advice and recommendations.

Adjacent to this are more formal oversight measures. The Plan will be reviewed quarterly and updated annually, to account for changes in conditions, incorporate lessons learned, and to build on progress, by annexing further actions each year. Thus 2020 will see a Climate Action Plan 2020, though one envisions that the governance structure and overall tenor will be preserved. The requirement to update the Plan annually will be a legal requirement following the promulgation of the Climate Action Bill. All Government memoranda and major investment decisions are subject to a carbon impact and mitigation evaluation.

The Plan reveals the intended proposal of a new Climate Action (Amendment) Bill, which will require future governments to design carbon budgets for three five-year periods, corresponding to the targets enumerated in this plan. Carbon budgets will set a limit on total emissions that can be produced in the State within a five-year period across the entire economy. Decarbonisation targets for each sector of the economy will be set thereunder, with the corresponding Minster accountable to the Oireachtas for its achievement. This will be codified in the proposed Climate Action Act; so too will the EU 2050 target of net zero carbon emissions, i.e. it will become a legal target, imbuing it with more weight.

Electricity:

The government aims for renewables to account for 40% of electricity generated by 2020. In 2017, 30% of electricity was produced by renewables; this, combined with increasing energy demands, renders the 2020 target a challenging one. Despite this, the Plan establishes the target of increasing electricity generated from renewable sources to 70% by 2030, with approximately 3.5 GW of offshore renewable energy; up to 1.5 GW of grid-scale solar energy; and up to 8.2 GW total of increased onshore wind capacity. These estimates should be seen solely as estimates and no maximum or minimum contributions by different generators have been identified, however, the Government may use the "levers" available to it in the Renewable Electricity Support Scheme (RESS) auction to attempt to influence the energy generation mix.

The majority of measures listed in the chapter on electricity amount to little more than a more rigorous application of existing policies, some of which are yet to be enforced such as the RESS. It calls for the harnessing of renewable energy by increasing the volume and frequency of RESS auctions, and an increase in corporate contracting for the development of offshore wind and solar energy. It advocates harnessing the 'significant potential' of Corporate PPAs to meet at least 15% of Ireland's 2030 electricity demand from renewable sources. However, it does not articulate how this will be achieved, it doesn't provide a system of incentives or structured financing, and it only mentions RESS auctions without accompanying detail of their design. It is dubious how this harnessing of potential will be realised.

The Climate Plan identifies the need to increase the level of storage and interconnection to enable greater access to electricity markets, encourages the Celtic Interconnector to France and further interconnection to the UK. It states the need for cross-border joint cooperation mechanisms for funding renewables, particularly offshore wind, but points to no strategy or template by which to actualise this. Then the Plan restates initiatives already in the pipeline such as the Marine Planning and Development Management Legislation (MPDM), Offshore Renewable Energy Development Plan (OREDP), and a new offshore grid connection policy aligned with the RESS auction timeframes.

It lays the groundwork for a micro-generation policy enabling those who generate their own electricity to sell it back to the grid. To support this, the government has established a pilot micro-generation grant scheme for solar Photovoltaics (PV), and is working on an ongoing support scheme for microgeneration. The government also anticipates changing the electricity market rules in early 2020 to allow micro-generated electricity to be sold to the grid, with a provision for a feed-in tariff for microgeneration to be set at least at the wholesale price point.

Insofar as the Plan regurgitates existing schemes, the endorsement of existing schemes is a positive thing, demonstrating consistent policy alignment. However, one would expect such soaring ambitions to be accompanied by similarly lofty policy aims.

Transport:

The transport sector remains the greatest consumer of energy in Ireland with a sustained reliance on fossil fuels, producing 19.7% of greenhouse gases in 2017. Throughout the Plan the government cites the need to sever the nexus between economic growth and emissions as an essential ingredient of decarbonisation. In the chapter on transport there is more direct engagement with this notion, as the paper recommends the nationwide substitution of existing gas combustion technology with electric vehicles. Forecast prosperity, population increases and the Irish *penchant* for private car ownership mean that the transport sector has the potential to derail efforts to reduce emissions. Consequently it is the recipient of some of the more novel proposals (in the Irish context at least).

The Plan sets the following noteworthy targets: reduce CO_2 eq. emissions from the transport sector by 45–50% relative to 2030 pre-NDP projections; dramatically increase the number of EVs to 936,000; build the EV charging network to support the growth of EVs at the rate required; develop fast-charging infrastructure to stay ahead of demand and make it a legal requirement for new, non-residential buildings with more than 10 parking spaces to be equipped with a least one recharging station. These targets serve the overall aim of 70% renewable electricity by 2030 and decarbonisation. A system of incentives and regulation will serve to gradually integrate subsidies for EV into successive budgets; along with a restructuring of motor taxes and the carbon-pricing policy, this should precipitate a transition to battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Ireland has already committed to a ban on the sale of new non-zero-emissions vehicles post-2030, and no NCT Certificate will be issued for non-zero-emissions cars post-2045. The plan anticipates an increase in the biofuel obligations on parties under the biofuel obligation scheme.

Building and retrofitting:

The Built Environment chapter has been celebrated as the most convincing chapter of the Plan insofar as it elaborates a clear strategy by which to achieve targets through capital investment, and provides a clear reference for implementation, i.e. the Dutch model of retrofitting, ‘Energiesprong’.

Irish buildings rely on fossil fuels for 70% of their energy consumption. To meet decarbonisation aims, Ireland must decrease built environment sector emissions to 5 Mt CO_2 eq. in 2030, requiring 40–45% emissions reduction relative to pre-NDP 2030 projections. The MACC analysis revealed the most cost-effective abatement measure to be retrofitting existing dwellings to upgrade energy systems to a B2 equivalent BER. The Plan contends that emission reduction targets can be met by: 1) retrofitting 500,000 buildings to B2 equivalent BER by 2030; 2) reaching *circa* 600,000 renewable energy heating sources (e.g. heat pumps) in residential buildings by 2030, and *circa* 25,000 in commercial premises; and 3) installing 600,000 heat pumps (400,000 to be in existing buildings).

Proposed measures associated with this roll-out include developing a smart finance initiative to encourage investment into low-carbon technologies; the envisioned system is a combination of low-cost loans, a grant element and advisory services. Reform of the regulation of new buildings is needed; it is proposed that from Q2 2019 all new buildings should be Nearly Zero Energy Buildings (NZEB), and existing dwellings undergoing major renovations should meet cost-optimal performance equivalent to a BER of B2 (see legislation section). These measures will be deployed gradually and progressively to minimise the energy cost of new buildings, through measures such as the phasing-out of boiler installations. New builds are required to achieve an energy performance improvement of 60% on the 2008 Building Regulations; in practice, this requires improved energy performance for fabrics, services and lighting specification. New builds must receive 20% of their primary energy use from renewable sources. In this respect, the Support Scheme for Renewable Heat (SSRH) should be harnessed to facilitate this transition.

Renewable Electricity Support Scheme (RESS)

The previous support scheme for the generation of electricity from renewable sources (Renewable Energy Feed-in Tariff (REFIT) scheme) has closed for applications, and projects holding REFIT 2 offer letters have until 31 March 2020 to meet the connection deadlines. REFIT's successor was revealed in July 2018 with the announcement by the Department of Communications, Climate Action and Environment of its intention to establish a new Renewable Electricity Support Scheme (RESS), and the publishing of a high-level design paper (the "High Level Design"). RESS is intended to operate by allocating long-term, two-way contracts for difference, capped by output (rather than capacity), to projects that are successful in RESS auctions. The High Level Design anticipates that in order to be eligible to participate in auctions, projects will need to satisfy community participation requirements, and to hold planning permission and a grid connection offer.

The first RESS auction was expected to occur in 2019 in respect of 1GWh of electricity from "shovel ready" renewable projects (RESS-1); this has been clarified as meaning the end of 2019 in the Climate Action Plan. However, commentators do not expect any auction before Q1 / Q2 2020 at the earliest.

A series of subsequent auctions out to 2025 (for project delivery by the end of 2030) are expected. There will be no single technology cap for the first auction, but this may change for subsequent actions.

RESS is to be procured by MWh (output) rather than MW (export capacity), and therefore the capacity factor of technology will be relevant to determining the amount of MWh awarded in the auctions. Separately, it appears that flexibility will be afforded in relation to the expected duration of the RESS contracts from auction to auction to potentially enable different technologies to succeed, with careful consideration being applied such that varying contract lengths do not negatively affect competition within the auctions.

In RESS 1 it is anticipated that successful applicants will be required to achieve energisation and connection to the grid by the end of 2020. This will obviously change.

The Climate Action Plan claims that RESS is expected to support up to an additional 4.5 GW of renewable electricity by 2030 and contains plans to intensify its activity beyond that envisioned even last year, i.e. increasing the volumes and frequencies of RESS, and integrating RESS with other policy areas such as Marine Planning. Despite this enthusiasm, there hasn't been much measurable progress in bringing RESS to market. The Department of Communications, Climate Action and Environment (DCCAE) has yet to publish a design paper detailing how exactly the auction will operate, or the precise eligibility criteria for participation so as to enable developers to prepare to bid for State aid. The formal line coming from the DCCAE as of March 2019 was that provisions contained in the Climate Action Plan may need to be accommodated in the final design of RESS. In the interim, the Department is working on the development of an enabling framework for community participation, and following government approval of detailed design of the first auction, stakeholder engagement can commence. In fact, the Climate Action Plan lists design and implementation of the RESS as a measure necessary to achieve renewable energy targets, indicating the scheme remains in its infancy. Nor has the State has been granted EU State Aid to support the project as at 2 September 2019.

This is a problem because the main existing renewable energy support scheme, REFIT, has closed for applications. This leaves a gap in State support for upcoming renewable energy projects. While we assume the Climate Action Plan shows a sincere intention to deliver further support to such projects, this lacuna in vital State aid may cause development to lag.

<u>Enduring Connection Policy (ECP-1)</u>

On 27 March 2018, the CRU introduced a new grid connection policy (ECP-1) in order to streamline the connection process and address a bloated 36GW list of generators seeking capacity (on a system that has 10.8GW installed, and a historical peak demand of only 5.1GW). Applications to qualify for this new policy opened on 27 April 2018 and closed on 28 May 2018.

On 31 August 2018, the list of applicants for new connection capacity that have been deemed "eligible for processing" under the 2018 iteration of the ECP-1 capacity allocation regime was released, known as the "2018 batch". A 1GW tranche of connection capacity was announced as part of this batch. The round was oversubscribed by 3.2GW of applications. Each listed applicant announced can be assured the system operators will process its application and will eventually schedule a connection offer date, provided the next instalment of the required connection application fees is paid.

400MW was to be prioritised in ECP-1 for applications related to projects that will be capable of supplying the DS3 fast frequency response and primary operating response products. DS3 projects in this category did not require planning permission in order to apply for connection capacity. However, they must meet grid code standards and must use proven technology. Battery storage technology was the major winner within the DS3 tranche, accounting for 351MW out of the 371MW allocated.

Given the extent of the applications received, the remaining capacity in the ECP-1 was allotted by order of priority, having regard to a project's planning status. Projects with soon-to-expire planning permissions were given priority, with the effect that among the successful applicants, the last planning permission expiry occurs in Q3 2023. No projects with planning permissions expiring after that date have been included. To reflect the practicalities of construction, minimum periods of planning permission validity were also included in the

ECP-1 process: expiry no earlier than 28 May 2020 (where a planning permission had been extended), or 28 May 2019 (where no extension had been received).

The non-DS3 component of the ECP-1 batch comprises 67 projects that have a total export capacity of 591MW. The ECP-1 announcement neither refers to RESS, nor includes any commitment from the System Operators as to the timing of connection dates relative to the RESS deadlines.

In addition to the ECP-1 batch, there are:

- 21 projects totalling 842 MW which already had live connection applications (sitting outside the earlier group processing regime), but which opted to be processed alongside the ECP-1 batch ("fold-in" applications). Of this, 841.5 MW is solar; and
- 34 projects totalling 436MW, where either capacity is being relocated or technology is changing.

The interplay between ECP-1 and Ireland's new RESS, will be crucial in determining the delivery of Ireland's next phase of renewable electricity generation projects.

A number of the projects in receipt of ECP-1 connections have planning permissions which expire during the course of 2019, 2020 and 2021. Therefore, based on the selection criteria, it is likely that these projects will be given connection dates that will enable them to compete for inclusion in RESS-1.

It is not yet clear what kind of connection dates these projects will now receive. The next application window is expected to be in 2020.

<u>National Smart Metering Programme</u>

The process of upgrading all existing electricity meters with Smart Enabled Meters will commence in Q3 2019 with the installation of 250,000 Smart Meters by ESB. It is a policy designed under Project Ireland 2040 and is overseen by the Climate Research Unit (CRU). The improved technology in these digital meters has the capacity to use energy storage technologies, and facilitate local renewable generation and micro-generation. When used with appropriate products and services (to be made available in 2021), Smart Meters enable consumers to shift consumption of electricity to off-peak times when it is cheaper. The benefits of these meters accrue with time and are seen as one of the many vehicles by which to achieve long-term energy efficiency. A further one million Smart Meters are expected to be installed in 2022.

Developments in legislation or regulation

<u>Fossil Fuel Divestment Act</u>

The Fossil Fuel Divestment Act was enacted on 17 December 2018. The Act amends the investment mandate of the Ireland Strategic Investment Fund (ISIF) to both prevent it investing in, and requiring it to divest from, fossil fuel undertakings over the next five years. This is a show of global leadership, as Ireland is be the first country to do so, and it is a huge move away from fossil-fuel investment dependency. If a sufficient number of other countries follow, this will stimulate investment in renewable and sustainable alternatives.

<u>I-SEM</u>

A distinct local manifestation of Irish electricity policy was the commencement, on 1 November 2007, of trading in the Single Electricity Market (SEM), the wholesale electricity market through which most of the electricity generated and consumed on the 'island of Ireland' (encompassing the Republic of Ireland, together with Northern Ireland) is required to be traded. The SEM began as a gross mandatory pool market, where a single-system, marginal price for energy was set '*ex post*', and the availability of generation capacity was rewarded by a regulated scheme of capacity payments.

During 2018, the redesign of the SEM was effected by way of the Integrated Single Electricity Market (i.e. I-SEM) project, which replaced the *ex-post* pool market with day-ahead, intraday and balancing markets for energy, and replaced the capacity payment arrangements with a 'capacity remuneration mechanism', under which capacity support is allocated by auction. The development of the energy trading arrangements within I-SEM was driven by the requirements of the network codes published under EU Regulation 714/2009 (which was also enacted as part of the third EU energy package).

The key changes ushered in by I-SEM are: new energy trading arrangements; capacity remuneration mechanisms; provisions for forwards and liquidity; and changes to market power, governance and licensing. I-SEM consists of several temporal markets with unique clearance and settling mechanisms. Irish energy market participants can now trade in forward, day-ahead, intraday and balancing markets.

I-SEM introduces 2 *ex-ante* markets for physical energy – 'the day ahead market' (DAM) and the 'intraday market' – both of which enable market participants to bid to buy and sell electrical output before it is produced. It is not until after the market clears that the energy is actually produced. Imbalances between the traded position and the actual output in respect of either market are resolved in the 'balancing market'. The DAM is a single pan-European energy trading platform which closes the day before delivery. It is 'the cornerstone of European market integration', in that it operates based on implicit allocation of cross-border capacity through a single centralised price coupling algorithm (EUPHEMIA) which, according to inputted cross-boarded capacity, sets the price and market positions for all participants in the coupled market.

The balancing market provides an energy-balancing service so that energy demanded equals energy supplied. It reconciles disparities between the market schedule and actual energy demand. In June 2018 it was confirmed that the REFIT support scheme, under which many Republic of Ireland wind farms receive financial support, would not insulate supported projects from the financial consequences of these imbalances. In order to optimise their revenues, REFIT generators therefore need to forecast their output (based on historical wind turbine performance and expected wind conditions), trade accordingly in the new I-SEM markets, and stand ready to take corrective trading actions as and when inaccuracies in their forecasts are revealed. Participation in the Balancing Market (BM) is mandatory for all dispatchable generators with a maximum export capacity above the *de minimis* threshold, and voluntary for dispatchable generators below that threshold. The first six months of I-SEM trading were the most volatile for the BM as it endured many instances of negative pricing.

I-SEM introduces a new capacity-remuneration mechanism; payment made in consideration for the capacity to produce energy, not for energy actually produced. It is remuneration for a readiness and ability to supply energy should consumers demand it, thereby promoting investment in generation capacity and securing energy supply. Under I-SEM, this object is served by a more competitive process of capacity remuneration, replacing the Capacity Payment Mechanism, whereby qualified capacity generators participate in an auction to obtain 'reliability options' for the provision of capacity.

<u>Strategic infrastructure developments and judicial review</u>

The Planning and Development Act 2000, as amended, provides for a special planning application process for strategic infrastructure development (SID). This procedure allows for the local planning authority to be bypassed entirely and the application to be made directly to An Bord Pleanála, the Irish State planning appeals board. SID status is afforded to developments which are considered of strategic importance to the State. They most commonly consist of energy infrastructure, transport infrastructure, large housing developments and environmental infrastructure projects. The scale and complexity of these developments often invites challenges by way of judicial review. Typically, applications to launch judicial review are made to the High Court, but as of February 2018, all applications for consent to launch a judicial review of permissions, or decisions concerning strategic infrastructure developments, may only be made to an assigned judge in the Commercial Court.

<u>New planning process for data centres</u>

The Seventh Schedule to the Planning and Development Act 2000 was amended by Section 49 of the Planning and Development (Amendment) Act 2018 which provides that certain data centre planning applications can be made directly to the Strategic Infrastructure Division of An Bord Pleanála. Data centres consisting of one or more than one structure, the combined gross floor space of which exceeds 10,000 square metres, will have SID status. Section 49 of the Planning and Development (Amendment) Act 2018 has not yet commenced. Once it is commenced, applications for data centres will benefit from a fast-tracked planning process. If the data centre requires a connection to the transmission system in order to meet its energy needs (a demand greater than 20MVA), an application directly to An Bord Pleanála for this transmission infrastructure may also be required.

<u>EU Regulations</u>:

- *SI No. 169/2018 European Union (Renewable Energy and Biofuel Sustainability Criteria) (Amendment) Regulations*. This regulation presents an overarching policy for the promotion and use of renewable energy in the EU as part of the Clean Energy for All Europeans package. It recapitulates the sustainability criteria of bioenergy and updates the rules on the Indirect Use of Land Change (IULC). IULC refers to a process in which biofuel production displaces cropland which, in turn, leads to the encroachment of agriculture into non-cropland of high carbon density, such as forests, wetlands and peat lands. This can undermine efforts to reduce greenhouse gases which form the purpose of investment and cultivation of biofuels.
- *The Renewable Energy Directive 2009/28/EC* and the *Fuel Quality Directive 2009/30/EC* addressed the risks of IULC and set limits on high IULC-risk biofuels, bioliquids and biomass fuels. These limits restrict the amount of these fuels Member States can include in their calculation of the share of renewables, i.e. only a certain amount of biofuels can service a Member State's national renewable target. There is, however, an exemption from limits for biofuels, bioliquids and biomass fuels certified as low-IULC-risk under the Directive. Fuels produced in excess of these limits can still be used and sold. The limits are frozen at 2019 for the period of 2021–2022, to decrease to zero by 2030. The Delegated Regulation (EU) 2019/807 was adopted to give effect to these limits, and articulates criteria for determining the high-IULC-risk feedstock for which a significant expansion of the production area into land with high carbon stock is observed; and certifying low-IULC-risk biofuels, bioliquids and biomass fuels.
- *S.I. No. 237/2019: EU (Renewable Energy) (Amendment) (No. 2) Regulations 2019*. This statutory instrument amends the European Union (Renewable Energy) Regulations 2014 which gave effect to Directive 2009/28, subject to subsequent amendments. This amendment refines terms contained in the original regulation such as 'quasable', and

reformulates the calculation for annualised emissions from carbon stock changes caused by land-use change.

- *S.I. No. 292/2019: EU Energy Performance of Buildings Regulations,* this legislation transposes articles 2, 7, 9 of Directive 2010/31/EU. It sets higher energy performance standards for buildings and applies in respect of dwellings or building renovations commencing 1 November 2019. It introduces an obligation, when a dwelling is undergoing a major renovation (where more than 25% of the surface envelope of the building undergoes renovation), that the energy performance of the whole dwelling should achieve a cost-optimal energy performance – where technically, functionally, and economically feasible. Transitional arrangements apply in relation to dwellings for which planning permission or approval is applied for on or before 31 October 2019, and where substantial work has been completed by 31 October 2020.
- *Waste Management (Facility Permit and Registration) (Amendment) Regulations 2019 (S.I. No. 250 of 2019)* amends the Waste Management (Facility Permit and Registration) Regulations 2007 (S.I. No. 821 of 2007) to increase the total maximum quantity of waste which may be recovered at a Class 5 activity facility as specified in Part 1 of the Third Schedule, from less than 100,000 tonnes to less than 200,000 tonnes on foot of a successful application for a waste facility permit.
- *European Union (Waste Electrical And Electronic Equipment) (Amendment) Regulations 2019 (S.I. No. 233 of 2019)*. This statutory instrument amends the European Union (Waste Electrical and Electronic Equipment) Regulations 2014 for the purposes of giving full effect to Directive 2012/19/EU on waste electrical and electronic equipment, to restrict the use of hazardous substances in electrical and electronic waste. It establishes the format for registration and reporting of producers of electronic/electrical equipment.
- *European Union (Greenhouse Gas Emission Reductions, Calculation Methods and Reporting Requirements) (Amendment) Regulations 2019 (S.I. No. 249 of 2019)*. Gives effect to Directive 98/70/EC as amended by Directive (EU) 2015/1513 of the European Parliament. Its purpose is to transpose elements of EU Directive 2015/1513 (Fuel Quality Directive) into Irish law.

Judicial decisions, court judgments, results of public enquiries

Connelly v An Bord Pleanála & Ors [2018] IESC 31

The Supreme Court, in *Connelly v An Bord Pleanála & Ors* [2018] IESC 31, decided on an appeal in relation to whether adequate reasons were given by An Bord Pleanála in its decision (the Decision). The Decision was in relation to an application for the development of a six-turbine wind farm. In the Decision, the Board stated that it was satisfied that the information before it was adequate to undertake an Environmental Impact Assessment (EIA) and an Appropriate Assessment (AA) for the proposed development.

The Supreme Court observed that the legal requirements which relate to different types of decisions can vary significantly depending on the circumstances. In certain decisions, a decision-maker may be required to determine whether very precise criteria are met, while other decisions will involve much broader considerations and a level of judgment on the part of the decision-maker.

The court identified two separate but closely related requirements at national law regarding the adequacy of any reasons:

(i) any person affected by a decision is at least entitled to know in general terms why the decision was made; and
(ii) a person is entitled to have enough information to consider whether they can or should seek to avail of any appeal, or bring judicial review of a decision. Also, the reasons provided must be such as to allow a court hearing an appeal or reviewing a decision to actually engage properly in such an appeal or review.

The application of these requirements will vary greatly from case to case.

In a case to which the environment impact assessment (EIA) regime applies, even though the general principle remains the same, the decision must be sufficiently clear to enable any interested party to consider whether they may have grounds to challenge the decision on the basis that an adequate EIA had not been conducted. This requires that the decision, or other relevant and connected materials available to any interested party, must demonstrate that an EIA was carried out and that the decision-maker properly had regard to the results of the EIA in coming to its conclusion.

In order for a valid appropriate assessment (AA) to have been conducted, there must be a precise identification of the potential risks and precise scientific findings to allay any fear of those risks coming to pass. This aspect is not, strictly speaking, a reasons issue. The issue concerns the validity of an AA decision which gives jurisdiction to the Board to grant permission. There must be complete, precise and definitive findings and conclusions which support the ultimate conclusion.

The Supreme Court held that neither the Decision itself nor any other materials which were expressly referred to in the Decision, or which must be taken by necessary implication to form part of the process leading to the ultimate determination of the Board, can be shown to contain the sort of complete, precise and definitive findings which would underpin a conclusion that no reasonable scientific doubt remained as to the absence of any identified potential detrimental effects on a protected site, having regard to its conservation objectives. Findings such as these are a necessary pre-condition to the Board having jurisdiction to grant development consent in a case where it is determined that an AA is required.

<u>Case C-461/17: Reference for a preliminary ruling from High Court (Ireland) made on 28 July 2017 – *Brian Holohan & Others v. An Bord Pleanála*</u>

The Court of Justice of the European Union (CJEU) answered the Irish High Court's request for a preliminary ruling on questions relating to the Environmental Impact Assessment Directive (85/337/EEC) and Habitats Directive (92/43/EEC), stemming from a High Court case on the approval of planning permission for a ring road. The case clarified what must be contained in a Natura impact statement, an Environmental Impact Assessment (EIA) and an Environmental Impact Statement (EIS).

This case has clarified a number of questions in relation to the Habitats and EIA Directives, particularly: what level of detail is provided in the Natura impact statement; what can be decided in a development post-consent; the reasons an authority must give when granting consent; what are "significant" effects; what constitutes a main alternative; and the reasons relating to environmental effects a developer must provide which guide them when choosing an option.

Major events or developments

<u>North-South Interconnector Project</u>

2018/2019 witnessed continued progress in the North-South Interconnector Project for the all-island electricity grid, a major electricity transmission line planned for construction across the border between Ireland and Northern Ireland. In February 2019, the Irish Supreme Court quashed the persistent challenge to An Bord Pleanála's decision to award planning permission, freeing up Eirgrid to progress with project development. However, planning permission for the northern element has too been subject to legal challenge, to which the Department of Infrastructure conceded. EirGrid and SONI, the transmission system operators for the south and north, respectively, are working to resolve this, for protracted delays on something as fundamental as planning permission slows meaningful development. As of June 2019, the framework contract for the design, test and supply of steelwork for the North South Interconnector has been awarded following a competitive tender process. However, the conclusion of the procurement process cannot happen until the re-approval of planning permission in Northern Ireland.

Launch of the Climate Action Fund

The Climate Action Fund is a €500m allocation of public funds to support the development of initiatives which contribute to the achievement of Ireland's energy and climate targets. It was introduced in 2018 under the auspices of Project Ireland 2040. The fund's implementation is governed by DCCAE and, since its launch in 2018, there have been seven successful applicants thereunder. The fund will run until 2027, with an initial allocation of €100m, and €50m per year thereafter. It is financed by government repurposing of part of the existing petroleum products levy (commonly known as the NORA levy) of 2 cents per litre that has been in place since 2007. The types of projects supported include: renewable energy projects; energy efficiency projects; district heating projects; and projects which enhance standards of environmental protection. The Fund aims to provide support to projects which build on existing public or private investment, i.e. those which exploit and augment existing initiatives. The first call for applications sought large-scale developments with funding support needs in excess of €1m, for which a maximum of 50% of the total investment requirement will be provided through the Fund. Future calls for applications may be sector-specific or require lower or higher overall capital requirements.

Support Scheme for Renewable Heat

The first phase of the Support Scheme for Renewable Heat (SSRH) has commenced. This €300m scheme supports the adoption of renewable heating systems by commercial, industrial, district heating and other non-domestic heat users not covered by the emissions trading system. It provides an installation grant to systems using air source heat pumps, ground source heat pumps or water source heat pumps. It also provides ongoing operational support in the form of a tariff based on useable heat output in renewable heating systems or financing for installations that use biomass boilers or biomass HE CHP heating systems or biogas (anaerobic digestion) boilers, or biogas HE CHP heating systems.

Proposals for changes in laws or regulations

Marine Planning and Development Management Bill 2019

On 10 June 2019, the Irish government released a Marine Planning Policy Statement (MPPS) outlining legislative measures aimed at streamlining the development consent process for the foreshore, including the integration of certain parts of the foreshore consent process (under the Foreshore Act 1933) with the existing on-land planning system. The current system is fragmented, without centralised control or objectives. Overall it is a very cumbersome system which inhibits the efficient exploitation of Irish offshore capacity.

The National Marine Planning Framework (NMPF) will serve as a marine equivalent to the National Planning Framework (under Project Ireland 2040), setting strategic objectives for the development of Ireland's marine area in respect of a 20-year period. The plan will serve as the edifice within which marine decision-making will unfold; it is a principled structure to support decision-making that is evidence-based, consistent and cognisant of sustainable development goals. The Department of Housing, Planning and Local Government is spearheading the development of Ireland's first marine spatial plan invoking government-wide participation. All plans proposed within the auspices of the NMPF will be considered in the context of their economic, environmental and societal impact. There is a sense with this package of reforms that marine activities are being elevated to a higher platform, so that decisions can be made in the light of broader national concerns. The abstruse, unwieldy predecessor is replaced by a big-picture, cohesive, integrated approach. The first draft of the NMPF is to be published in Q3 2019. The NMPF has its statutory basis in the Planning and Development (Amendment) Act 2018 which gave effect to the European Marine Spatial Planning Directive (Directive 2014/89/EU).

The Marine Planning and Development Management Bill 2019 has the principal objective of modernising elements of the marine development management and enforcement systems, replacing the antiquated and complex Foreshore Act 1933.

It enhances planning capacities, giving new powers for the Minister for Housing, Planning and Local Government to put in place statutory marine planning guidelines (parallel to statutory planning guidelines under Section 28 of the Planning and Development Act 2000).

Importantly, it introduces a single State consent system which empowers the Ministers for Housing, Planning and Local Government and Communications, Climate Action and Environment to issue State consents for the control of the foreshore, territorial sea, Exclusive Economic Zone and continental shelf, and to grant leave to projects to apply for development consent/planning permission to An Bord Pleanála or local authorities.

The Bill designs a single development management process for certain categories of project in the Maritime area, including offshore renewable energy, and removes duplication of development management processes for activities currently being considered under both foreshore and planning regimes; for example, wind farms are subject to assessment under both regimes.

Amendments to the Planning and Development Acts 2000–2012, to the Foreshore Acts 1933–2012 and to the Dumping at Sea Acts 1996–2012 are also proposed.

<u>Wind energy development guidelines</u>

In June 2017, the Minister for Housing, Planning, Community and Local Government, in conjunction with the Minister for Communications, Climate Action and Environment, announced a preferred draft of the approach to address the key aspects of the review of the 2006 Wind Energy Development Guidelines. The approach taken is the application of a more stringent noise limit, in tandem with a new robust noise monitoring regime. The key aspects of the preferred draft approach are:

(i) new noise restriction limits of a relative rated noise limit of 5dB(A) above existing background noise within the range of 35–43dB(A) for both day and night, with 43dB(A) being the maximum noise limit permitted;

(ii) for visual amenity purposes, each turbine should be set back from the curtilage of a residential property by a distance of at least four times its tip height, subject to a mandatory minimum setback of 500 metres;

(iii) the adoption of technology that will shut off each wind turbine automatically to eliminate any shadow flicker;

(iv) a Community Report, which describes how the proposed wind farm was designed in response to consultation with communities, will have to be submitted along with each planning application;

(v) the applicant will need to offer a form of community dividend, that will ensure the project is of enduring economic benefit to the communities concerned; and

(vi) from a visual amenity aspect, grid connections to wind farms should be underground.

The proposed approach will be further supported by the Good Practice for Wind Energy Development Guidelines, issued in 2016 by the Department of Communications, Climate Action and Environment.

A Strategic Environmental Assessment (SEA) of the draft approach to the revised guidelines will be undertaken before they are finalised. These draft guidelines were due to be released in Q1 2019, and a public consultation undertaken together with the comprehensive environmental report. As of writing, no guidelines have been published; the Minister for Housing, Planning and Local Government points to the new WHO noise standards, and Brexit-related planning issues, as the cause of delays. Following the completion of the SEA, the guidelines will be finalised and issued under section 28 of the Planning and Development Act 2000 and will apply to planning applications for future wind energy development proposals. Currently the 2006 Guidelines are still in effect.

<u>Publication of Ireland's first National Policy Statement on the bio-economy</u>

This paper sets out the environmental and economic case for building a 'bio-economy' and establishes a high-level Implementation Group to issue recommendations for development and bring policy coherence to the aims contained in the Policy Statement. It will be chaired by the Ministers for the Departments of Agriculture, Food and Marine and Communications, Climate Action and Environment. The bio-economy refers to the production of renewable biological resources and the conversion of these resources and waste streams into value-added products, such as food and bio-energy. The Statement includes a commitment to develop a supporting and enabling policy framework to facilitate the delivery of a successful bio-economy in Ireland. Its main pillars are: investment in research; development of markets and competitiveness; and reinforced policy co-ordination and stakeholder engagement. To these ends, the government has already provided modest investment aimed at catalysing industry development, including a Bioeconomy Research Centre (Beacon) and the establishment of the Irish Bioeconomy Foundation, to bring together relevant stakeholders. Going forward, the main initiatives in the short term are based on understanding the bio-economy as it currently stands, identifying opportunities and incremental development.

<u>Changes to the electricity market rules</u>

It should here be noted that the Climate Action Plan calls for a change to the electricity market rules in early 2020 to facilitate the sale of micro-generated electricity to the grid. The only guidance given as to what this change would involve is the inclusion of provision for a feed-in tariff for micro-generation to be set at least at the wholesale price point.

This authors are unsure how these or any proposed changes will interact with the existing market arrangements and EU legislation governing the Internal Electricity Market.

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Overview of the current energy mix, and the place in the market of different energy sources

The energy sector in Israel has witnessed steady growth over the past few decades. According to official figures, total electric power production in the Israeli market has increased from approximately 53.5 billion kWh in 2009 to 73 billion kWh in 2018, an incremental increase of 32%, compared to a 19% increase in population and a 61% increase in production of goods over that time period.

Total electric power production in the market has increased steadily over the years, apart from 2013, in which total electric power production in the market fell by 3.2%.

In the upcoming decade, electric power consumption is expected to continue rising, due to natural population and economic growth as well as national infrastructure initiatives such as electrification of railway lines and growth in the electric vehicle sector. There are various forecasts for the increase in electric power consumption – according to the Bank of Israel, the annual rate of increase in electricity demand is expected to range between 2.7% and 3%.

In 2018, electric power production in the Israeli market came from the following sources: approximately 29.3% from coal; 33.2% from natural gas; 4.4% from liquid natural gas (LNG); 0.6% from diesel; and 0.1% from fuel oil. The Israel Electric Corporation (IEC), a government company, produced a total of 47.5 billion kWh of electricity, about 67.6% of the total electricity production in the market in 2018. Production by independent power producers (IPPs) using natural gas (private power stations) was approximately 29.3%, and electricity production from renewable energy sources was 2.9% of the total in 2018.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Statements by Israel's Ministry of Energy, outlined below, indicate that by 2030 the distribution of fossil fuel use in the Israeli market is expected to be drastically different from the distribution documented in 2010, with a significant increase in natural gas consumption at the expense of other energy sources. In 2013, natural gas accounted for only 26% of total energy sources in the market, in reference to the total consumption of 23,700 tons of oil equivalent (TOE). The national Gas Authority estimates that by 2030 total energy consumption in the economy will reach 34,900 TOE, and projects that natural gas will make up 47% of all energy sources in the market. This change will stem primarily from the expected use of natural gas sources discovered in recent years in Israel's exclusive economic zone (EEZ). A detailed description of these reservoirs follows.

In the last decade, several reservoirs of natural gas have been found in Israel's EEZ, in the

Mediterranean Sea, west of the country's coastline. Some of the reservoirs are small, containing minimal quantities that are not economically significant, but some are giant reservoirs with commercial potential and are already in use by IEC and various industrial operations.

The "Tamar" reservoir is a natural gas field that lies in the Mediterranean Sea about 90 kilometres west of Haifa and at a depth of about 1,700 metres below the sea surface. Although it is not the first gas field with economic potential to be discovered in Israel, as of this article. "Tamar" is the only active natural gas reservoir, producing 10 billion cubic metres (BCM) of natural gas per year. The total quantity of gas that can be extracted from the reservoir has been estimated at 307 BCM.

The "Leviathan" reservoir is a natural gas field in the Mediterranean Sea, about 130 kilometres west of Haifa (and to the west of the "Tamar" reservoir) and at a depth of about 1,500 metres below the sea's surface. The reservoir was discovered in late 2010, and is one of the largest discoveries in the world of natural gas in deep waters. Experts estimate its volume at 621 BCM of natural gas, in addition to 40 million barrels of natural gas condensate, making the "Leviathan" highly promising for Israel's energy market and as an engine of significant economic growth for the country and its citizens.

Two smaller gas reservoirs have also been discovered, known as "Karish and Tanin" (Shark and Alligator), located in the northern region of Israel's EEZ. The "Tanin" reservoir was discovered in 2011 to the northeast of the "Leviathan" reservoir, and the volume of natural gas it contains is considered the third in size to be discovered on Israeli territory. The "Karish" reservoir was discovered in 2013 to the northeast of the "Tamar" reservoir and is believed to be the fourth-largest in the country's territory. In total, it is estimated that the "Karish" and "Tanin" reservoirs contain between 60 and 70 BCM of natural gas, and their development, drilling, and transport costs are expected to be lower than the corresponding costs for the "Tamar" and "Leviathan" reservoirs. This is due in part to their size and in part to their relatively short distance to other reservoirs, which would allow the "Karish" and "Tanin" reservoirs to make use of the infrastructures in place for "Tamar" and "Leviathan".

Over the past year, alongside the supply of natural gas to the Israeli energy market from the "Tamar" reservoir, development work continues apace on the (permanent) production platform for the "Leviathan" field, which will be located in Israel's territorial waters (approximately 10 kilometres from the coast). Construction of a floating production storage and offloading (FPSO) unit is also under way, for gas extraction from the "Karish and Tanin" reservoirs.

The total quantity of natural gas consumed in Israel has risen, as construction of a pipeline transmission system progresses. The pipeline's construction has been carried out by the government owned corporation "Israel Natural Gas Lines Ltd."(INGL) ever since that corporation's founding in 2003. The overall length of the system, as of today, is approximately 650 km.

INGL is currently working on several additional projects, in various stages of planning and installation, including installing additional sections and doubling existing lines. INGL is also continuously increasing the number of clients and hooking up additional consumers to the system.

On August 16, 2015, a significant governmental decision was made (re-adopted in a decision on May 22, 2016), entitled "A Draft Plan for Increasing the Quantity of Natural Gas Extracted from the 'Tamar' Natural Gas Field and Rapid Development of the 'Leviathan', 'Karish', 'Tanin' and other Natural Gas Fields" (the "Gas Draft Plan") which took effect on

December, 17, 2015. The draft plan includes nine chapters detailing the government's intentions regarding management of the natural gas industry. It is intended to accelerate development of the gas reservoirs and promote their incorporation into the Israeli energy market. The Gas Draft Plan underwent judicial review by the Supreme Court sitting as the High Court of Justice, and the Israeli market began to implement the plan; since then, significant progress has been seen in the development of Israel's natural gas industry.

Developments in government policy/strategy/approach

On July 26, 2018, an amendment to the Electric Power Sector Law went into effect, mandating and regulating reform of the electric power sector in Israel. The amendment to the law resulted from a government decision on reform of the electric power industry, in accordance with policy principles publicised by the Minister of Energy. Principles of the reform include steps to increase competition in the electric power industry and improve the efficiency of IEC (the governmental corporation for production, transport, and distribution of electricity), as described below:

1. Management of the electric power system – Management will be transferred from IEC to another government company (System Management Company Ltd.), with the goal of reducing existing conflicts of interest between the producers and the system manager.
2. Production section – IEC will gradually, over a five-year period, sell five sites for production of electric power using natural gas, amounting to a potential output of 4,500 megawatts (representing approximately one-third of the company's production output and a quarter of the overall production output of the market, as of December 2017), on-land sites for the construction of additional production sites (at Rutenberg and at Reading). This year, IEC sold the first power station in Alon, in the Galilee region, and began the process of issuing a tender to sell a second power station, in Ramat Hovav in the Negev region. IEC will not build additional power stations, except for future replacement of four coal-fired electricity production units at the "Orot Rabin" power station in the city of Hadera, with electricity production units powered by natural gas. A subsidiary will be created that will own the new combined-cycle power plants to be built at the "Orot Rabin" site.
3. The transmission section – This will remain entirely under IEC's control since it is a natural monopoly.
4. The distribution section – Because of the advantage of the existing size in the distribution section, this section will remain largely under IEC's control, except for existing licensed distributors, who will be permitted to operate their distribution territories, under the restriction that these distribution licences will not exceed 10% of the annual consumption in the market, accounting for natural growth of consumption in the distribution territories.
5. The supply section – This section will be opened up to competition. IEC will not compete in the supply section for ultra-high voltage, extra-high voltage, and high voltage, but instead will charge according to the rate determined by the Electric Power Authority. In the low-voltage supply section, IEC will be permitted to compete only if its market share in this sector is be less than 60%.

Implementation of the reform has begun and has been implemented this year in accordance with the plan, but the process is far from completion.

Developments in legislation or regulation

Natural gas for transportation

On January 16, 2017, The Natural Gas Commission (appointed by the Government subject to the Natural Gas Sector Law) decided to promote the use of natural gas in Israel as an alternative energy source for transportation. As part of that decision, the regulatory arrangement was set to determine the prices for filling stations that provide compressed natural gas (CNG), emphasising the importance of transmission of the gas to make it available for transportation purposes. This follows a governmental decision of January 13, 2013, which called for transitioning of the Israeli public transportation from petroleum to alternative energy sources by 2025. The decision called for reducing the proportion of petroleum as an energy source for Israeli transport by 30% in 2020 and 60% in 2025, relative to the projected consumption in these years, as long as the transition is economically viable.

The Ministry of Energy's official forecast for natural gas use in the transportation sector by different types of vehicles (buses, taxis, trucks, private vehicles etc.), is 1.3 BCM in 2030 and 4.7 BCM in 2040.

Encouraging renewable energy sources and reducing the use of coal as an energy resource

On April 2, 2017, a governmental decision determined conditions and criteria for authorising independent bodies to create national infrastructure plans for facilities that produce electric power, for submission to the National Infrastructure Committee (the committee was set up in 2002 in Israel with the objective to shorten the planning and approval phases for large and important infrastructure projects). According to the decision, authorisation will be granted to bodies which are interested in building electricity-generating facilities that use natural gas or renewable energy, or electricity storage facilities. Approval of these licensing applications will continue until plans have been approved for the generation of 25,000 megawatts in total, as stipulated, by 2040. Of these, 13,000 megawatts of electricity will be produced via renewable energy sources, including energy storage. This decision goes beyond plans that have already been approved as of the date of decision.

Moreover, on November 12, 2017, the Minister of Energy announced a decision on "Policy Principles regarding the Marginal Operation of Coal-Burning Production Units". According to this decision, electricity generation via natural gas shall be prioritised over coal, with the coal-burning units operating at the minimum levels needed to ensure a reliable, flexible supply of electricity to the Israeli market. The policy will be implemented after ceasing continuous operation of the four coal-burning electricity production units at the "Orot Rabin" power station. Implementation will be subject to the existence of natural gas surplus in the infrastructure linking the three natural gas reservoirs, each of which will have a separate infrastructure for connecting to the national natural gas pipeline system.

Furthermore, on January 2, 2018, the website of the Ministry for Environmental Protection publicised a joint decision by the Minister of Energy and the Minister of Environmental Protection, stating that the IEC would reduce its use of coal for electricity generation by 30% (compared to the base year, 2015), effective immediately. The decision stated that this reduction of coal use would be steeper than the 2017 reduction, which was 20% compared to the base year. The decision also stated that it would bring about a significant reduction in air pollution from coal-burning power plants, and is expected to increase the demand for natural gas. Accordingly, in June–July 2018, governmental decisions about the electric power industry and about structural changes in the IEC were announced; the decisions discussed shutting down the four coal-fired power stations at the "Orot Rabin" facility.

On October 9, 2018, the Ministry of Energy publicised the "Plan for Saving Israel from Polluting Energy Sources", which set out concrete steps and goals for using natural gas in electricity generation, industry, and public transportation towards 2030. The goals set for 2030 include:

1. In the electric power production sector: that electric power production be divided between natural gas and renewable energy sources at proportions of roughly 80% and 20% respectively, while closing the coal-fired power plants in Hadera and Ashkelon, and ending the use of coal in electric power production.
2. In the industry sector: about 95% of the energy and steam required for industry shall be generated using natural gas.
3. In the transportation sector: a gradual transition to electric cars and natural gas-fuelled trucks, and a strict prohibition on importing cars that run on high-pollution fuels.

Judicial decisions, court judgments, results of public enquiries

Any discussion of the Israeli energy market must reflect the harsh criticism expressed by Israeli environmental non-governmental organisations (NGOs) about the country's limited use of renewable energy sources. As they see it, Israel is still extremely backward in making use of renewable energy sources to generate electricity – even lagging behind the goals that the Government has set for the State of Israel. At present, renewable energy sources account for 3% of the total electric power produced.

In this context it is important to note that, under its commitment to the Paris Agreement, the Israeli government adopted a national plan, stating the goal of having at least 17% of electric power consumption come from renewable energy sources by the year 2030.

The State of Israel has significant potential to produce electricity from renewable sources, particularly solar energy. Extensive areas of the country, especially in the South, are bathed in sunlight practically year-round. Even in the winter months, those areas receive enough sunlight to produce a large amount of electricity. Distances within the country are relatively small, so electricity from solar power plants can be transmitted to consumers in other regions with relative ease. A large amount of capital is available from pension funds to finance the building and operation of such infrastructure projects, and international stakeholders are relatively enthusiastic about financing this kind of project in Israel – a country with a robust economy and good credit rating. In light of this, environmental organisations are demanding that the government produce much more electric power from solar energy.

Critics blame government ministries for holding back the renewable energy industry – or to be more precise, they point to a lack of cooperation and coordination among the ministries. A wide range of governmental bodies are involved in developing the statutory, administrative, and regulatory infrastructure required to build a power station based that uses renewable energy. To illustrate the complexity of the issue: the Planning Administration of the Interior Ministry has a governmental mandate to identify plots of land suitable for building power stations; the Israel Lands Authority is mandated to issue tenders for allocating the land, and to set the appropriate leasing and improvement fees for using the land; and finally, the Electric Power Authority of the Ministry of Energy is mandated to set the rate that IEC will pay the producers for the electricity produced from renewable sources. This rate must be calibrated such that on the one hand, entrepreneurs will be encouraged to build power stations based on solar and other alternative sources, while sparing the public from paying exorbitantly high prices for electricity.

Despite the slow pace at which Israel has adopted renewable-energy technologies for generating electric power, Electricity Authority officials are optimistic. The Authority's 2018 annual report states that, in spite of the challenges, the Authority estimates that the 2020 goal – having 10% of Israel's electric power generated from renewable energy sources – can be reached. Governmental decisions indicate a positive trend, supporting implementation of the determined goals. It should be noted, however, that due to general elections in 2019, there has been a certain delay in the administration of government processes, on this issue and in general. Acceleration of the government's efforts to support solar-powered electricity production will enable a gradual increase in Israel's clean electricity.

Major events or developments

The vast energy resources discovered in the Mediterranean Sea have significant economic potential as well as potential to strengthen relations between the countries of the region including: Israel, Egypt, Jordan, Turkey, and Cyprus, as well as with the Palestinian Authority. Economic ties in the energy sector may lead to strengthening international relations, given the economic and political benefits that they can confer on all of the participants.

Agreements in the gas sector require long-term contractual relationships, generally for a number of decades, and they involve physical connections between countries via transmission pipelines. Thus, they could strengthen commercial relations and contribute to regional economic stability. Regional cooperation in the sector of gas and energy, which will grow hopefully in the future, can increase the responsible and stabilising factors in the Middle East.

Israel began exporting gas at the end of the fourth quarter of 2016, when it began supplying gas from the "Tamar" reservoir to the Arab-Potash and Jordan Bromine factories on the Jordanian side of the Dead Sea.

In addition, "Leviathan" operators signed a contract in September 2016 with the Jordanian electric company (NEPCO). They contracted to supply a total of approximately 45 BCM over a period of 15 years for producing electric power for the local Jordanian economy. This is a historic export agreement, being the largest gas export agreement signed with the Jordanian kingdom, and also the first signed agreement involving the "Leviathan" reservoir. This agreement is intended to serve as an anchor in the region, both geopolitically and in the energy sector.

In early 2018, the operators of "Tamar" signed an agreement to supply natural gas to the Egyptian firm, Dolphinus Holdings. This agreement is based on the surplus quantities of gas that the "Tamar" operators will have available, for a period of seven years from the time they begin supplying gas. The agreement sets a minimum cumulative supply amount of 5 BCM during the first three years, intended for consumption by the local Egyptian economy. This agreement depends on having infrastructure in place that will allow gas to be transported from "Tamar" to the Egyptians.

Israel is the main supplier of electricity to the Palestinian Authority. However, the Palestinian Authority has begun a process to create the capacity for independent power production, in part by building electric power generating power plants. Operators of "Tamar" and "Leviathan" have reported that they are in contact with various parties regarding the possibility of supplying natural gas to power plants in Gaza and in the area around Jenin.

In parallel, INGL (governmental company) is planning various export projects, including to the Palestinian Authority, as follows:

On October 28, 2018, INGL reported the beginning of negotiations with the Tamar gas consortium regarding the possibility of transmitting natural gas to Egypt via the pipeline infrastructure.

INGL is carrying out planning for a new pipeline segment to connect to a power plant and to additional consumers in the Gaza Strip, as part of a project initiated by several international parties.

The Gas Authority is also progressing plans for a new pipeline section to hook up to a planned power station in Jenin. In April 2017, an agreement was signed between Gas Routes and the entrepreneurial company building the Jenin power station, under which the planning costs for this section will be financed by the entrepreneur.

Furthermore, in December 2017, the Foreign ministers of Israel, Cyprus, Greece, and Italy signed a memorandum of understanding to construct a gas pipeline that will carry natural gas from the "Leviathan" natural gas reservoir to Italy. The planned pipeline is approximately 2,100 kilometres long, and will cost an estimated US$7 billion. It is expected to be completed in 2025. At the signing of the agreement, the ministers described it as a strategic infrastructure project for managing natural gas that is in the interest of all the countries as well as the European Union. The European Union representative estimated that Europe will need to increase its imports of natural gas by 100 BCM per year because of decreasing gas production from the North Sea, and that Europe views Israel and Cyprus as secure sources of gas supply in the future.

Such projects are undoubtedly of significant economic importance to the energy market, and involve complex national and international legal aspects. As such, as these projects progress, they will likely warrant further attention and discussion in future issues of this journal.

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Japan

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Overview of the current energy mix, and the place in the market of different energy sources

Since the wake of the first oil shock in 1973, Japan has sought to decrease its dependence on oil by promoting nuclear power, natural gas and coal as alternative energy resources. By FY 2010 Japan had successfully diversified its primary energy sources (coal (22.5%), natural gas (19.2%) and nuclear (11.1%)), and dependence on oil as a primary energy source was significantly reduced from 75.5% in FY 1973 to 40.3% in FY 2010.

However, due to the Great East Japan Earthquake and the resulting nuclear accident at Fukushima Daiichi Nuclear Power Plant ("**Fukushima Nuclear Accident**") and shutdown of other nuclear plants in March 2011, imports of fossil fuels as an alternative to nuclear power increased, resulting in dependence on fossil fuels as primary energy sources surging again (to 91.6% in FY 2012 from 82% in FY 2010). However, due to several nuclear power plants restarting operation and an increase in renewable energy (particularly solar power), demand for fossil fuels as primary energy sources has gradually decreased in the last few years, declining to 87.5% in FY 2017.

Although the FY 2018 figures are not yet available, the following tables show the recent status of the primary energy domestic supply and power source mix.

Table 1: Primary Energy Domestic Supply (FY 2012–2017)

Year	Oil	Coal	Natural Gas	Nuclear Power	Hydro Power	Renewable Energy (excluding hydro power)	Unutilized Energy
2012	44.5%	23.6%	23.5%	0.7%	3.2%	2.1%	2.5%
2013	42.8%	25.2%	23.3%	0.4%	3.2%	2.5%	2.6%
2014	41.2%	25.2%	24.5%	0.0%	3.5%	3.0%	2.7%
2015	40.7%	25.8%	23.3%	0.4%	3.6%	3.6%	2.7%
2016	39.7%	25.4%	23.8%	0.8%	3.3%	4.1%	2.9%
2017	39.0%	25.1%	23.4%	1.4%	3.5%	4.7%	3.7%

(*Source: Agency for Natural Resources and Energy, Energy demand and supply result in FY 2017 (confirmed report) dated April 2019.*)

Table 2: Power Source Mix (FY 2012–2017)

Year	Oil	Coal	Natural Gas	Nuclear Power	Hydro Power	Renewable Energy (excluding hydro power)
2012	17.5%	31.0%	40.1%	1.5%	7.1%	2.8%
2013	14.5%	32.9%	40.9%	0.9%	7.3%	3.5%
2014	11.1%	33.4%	43.0%	0.0%	7.9%	4.6%
2015	9.8%	34.1%	40.9%	0.9%	8.4%	5.8%
2016	9.7%	32.8%	41.2%	1.7%	7.6%	7.0%
2017	8.7%	32.7%	39.5%	3.1%	7.9%	8.1%

(*Source: Agency for Natural Resources and Energy, Energy demand and supply result in FY 2017 (confirmed report) dated April 2019.*)

Developments in government policy, strategy and approach

Energy mix plan

The 4th Strategic Energy Plan ("**Previous Strategic Energy Plan**") was approved by the Japanese Cabinet in April 2014 to reset Japanese energy policy after the Fukushima Nuclear Accident.

The Previous Strategic Energy Plan was affected by the significant impact of the Fukushima Nuclear Accident on Japan's energy environment. For example, under the 3rd Strategic Energy Plan approved in June 2010, the target for FY 2030 was for zero-emission power sources consisting of nuclear power and renewable energies to total approximately 70% of the power mix. However, given the tremendous disaster caused by the Fukushima Nuclear Accident, Japan reconsidered its energy strategy from scratch and the Previous Strategic Energy Plan declared that Japan would minimise its dependence on nuclear power. Furthermore, the Previous Strategic Energy Plan confirmed the "3E + S" policy, whereby "*Energy Security*" (ensuring a stable supply of energy), "*Economic Efficiency*" (developing a low-cost energy supply by enhancing efficiency), "*Environment*" (making maximum efforts to pursue environment suitability), and "*Safety*" would be the basic pillars of the overall policy.

In July 2015, based on targets established to realise the "3E + S" policy, the Ministry of Economy, Trade and Industry ("**METI**") publicised the Long Term Energy Supply and Demand Outlook ("**2015 Outlook**") whereby the targets for the primary energy supply structure and the electric power supply-demand structure in FY 2030 were set as:

Table 3: Primary Energy Supply in FY 2030

Oil	LPG	Coal	Natural Gas	Nuclear Power	Renewable Energy
30%	3%	25%	18%	10–11%	13–14%

Table 4: Power Source Mix in FY 2030

Oil	Coal	LNG	Nuclear Power	Renewable Energy (22-24%)				
				Hydroelectric Power	Solar	Wind	Biomass	Geothermal Power
3%	26%	27%	20–22%	8.8–9.2%	7.0%	1.7%	3.7–4.6%	1.0–1.1%

As shown above, it was expected in the 2015 Outlook that renewable energy's share of electricity generation would significantly increase from around 12.6% in FY 2014 to around

22–24% in FY 2030, while dependence on nuclear power, which was around 30% before the Great East Japan Earthquake, was expected to decrease to around 20–22%. As a result, it is expected that zero-emission power sources consisting of nuclear power and renewable energy should be approximately 44% in total in FY 2030, and the base load rate (consisting of hydropower, coal-fired thermal power and nuclear power, etc.) will be around 56% in total.

In 2017, a formal review of the Previous Strategic Energy Plan began at the Advisory Committee for Natural Resources and Energy ("**Advisory Committee**"), where the energy mix target for FY 2030 was reviewed based on developments during the preceding three years. However, as discussed below, after discussions the Advisory Committee decided that the energy mix in the 2015 Outlook would not be changed.

5th Strategic Energy Plan

The 5th Strategic Energy Plan was proposed by the Advisory Committee to the Cabinet based upon the result of the Advisory Committee's discussions. It seems that the most controversial issues discussed were how to realise the energy mix targets for renewable energy (22–24%) and nuclear power (20–22%).

(a) *Issues discussed in connection with renewable energy target*

After introducing the Feed-in Tariff ("**FIT**") system in Japan in July 2012, the volume of power produced through renewable energy has steadily increased, from 10% in 2010 to 15% in 2016. However, as a result of such increase, two trillion yen per year was required for the purchase cost under the FIT system, while the purchase cost for a further 9 percentage point increase (i.e. from 15% to 24%) is budgeted for only an additional one trillion yen per year. As a result, how to further increase renewable energy capacity in an economically efficient manner is one of the important issues to be resolved.

For the initial five years of the FIT system, the generation of solar power has disproportionately increased compared with other renewable energy sources which require a longer lead time due to regulatory and other hurdles (e.g. environmental impact studies are generally required for offshore and onshore wind, geothermal and hydroelectric power facilities). Therefore, it was confirmed that regulatory hurdles should be rebalanced to encourage other types of renewable energy sources.

In addition, the vast majority of the increase of renewable energy capacity is expected to rely on naturally fluctuating power sources (e.g. solar power and wind power). Thus, sufficient base load capacity (e.g. coal-fired thermal power or nuclear power) and/or storage batteries to adjust the power output fluctuations of those renewable energy sources will be required.

Finally, as many solar and wind power facilities are expected to be installed in rural areas, increasing grid capacity to accommodate the need for decentralised power will be an additional challenge for continued increases in the use of renewable energy.

(b) *Issues discussed in connection with nuclear power*

The energy mix target for nuclear power in 2030 was set at 20–22% in the 2015 Outlook. Achieving such target is expected to require resuming operation of around 30 nuclear power plants. However, some members of the Advisory Committee strongly criticised such target, believing that the energy mix target for nuclear power is unrealistic unless replacement of the existing plants or construction of new plants is contemplated.[1] However, it seems that no detailed discussions were held regarding replacement or new construction by the Advisory Committee.

On July 3, 2018, the 5th Strategic Energy Plan was finally approved by the Cabinet. One point highlighted in the 5th Strategic Energy Plan is that renewable energy was cited as a "major power source", demonstrating that the Japanese government is targeting an increase in renewable energy capacity, although as mentioned above there are a number of issues to be resolved to achieve the targets. The measures adopted in Japan with a view to promoting renewable energy in an economically efficient manner are described below.

Development of FIT system in Japan

1. **Introduction of FIT system**

One of the key factors for achieving the targets set in the energy mix plan in the 2015 Outlook was how to introduce and expand renewable energy as much as possible while minimising the public burden. As the driving force for promoting renewable energy, the FIT system was introduced in Japan in July 2012 pursuant to the Act on Special Measures Concerning Procurement of Renewable Electric Energy by Operators of Electric Utilities ("**Old Feed-in Tariff Act**"). For a power producer to be entitled to sell electricity at a certain fixed price (the "**Tariff**") for a certain period ("**Tariff Period**") under the Old Feed-in Tariff Act, it was generally required to: (i) obtain certification of power generation facilities from METI ("**Facility Certification**"); (ii) apply to a general transmission and distribution operator for a grid connection and enter into a grid connection agreement;[2] and (iii) enter into a power purchase agreement with an electricity retailer.

Under the Old Feed-in Tariff Act, METI could set different tariffs and tariff periods annually or semi-annually, depending on the renewable energy category and other conditions after taking into account various factors (e.g. (i) costs to be ordinarily incurred by power producers, (ii) whether renewable energy power producers can obtain an appropriate level of profits, (iii) the nationwide supply of renewable energy-based electricity, and (iv) the public burden (i.e. amount of surcharges)).

2. **Issues identified during the initial phase of the FIT system**

As a result of introduction of the FIT system in Japan, renewable energy generation increased by more than 2.5 times during the initial four years. However, total annual purchase cost for renewable electricity under the FIT system had reached 3.1 trillion yen in FY 2018, while the total annual purchase cost in FY 2030 targeted under the energy mix plan in the 2015 Outlook is around 3.7–4.0 trillion yen. Therefore, cost-efficient introduction of renewable energy has been highlighted as a major issue under the FIT system in Japan.

In addition, the introduction of additional renewable energy capacity during the initial four years was heavily tilted toward solar power generation, as 90% of the capacity certified under the FIT system was solar power. Unlike geothermal, hydro and biomass, which can be operated stably in any weather conditions and therefore can be expected to replace nuclear power as base load capacity, solar power, whose output fluctuates greatly depending on natural conditions, is required to be accompanied by base load capacity (e.g. coal-fired thermal power or nuclear power) as an adjusting power source.

Furthermore, it was reported that around 340,000 solar power projects having Facility Certifications issued during FY 2012 and 2013 had not started commercial operation as of December 31, 2015, but were keeping priority over grid connection rights, which may cause opportunity losses by other projects with high potential.

In addition, as Japan's grid system had developed for a long time on the basis that power sources were centralised (e.g. thermal power and nuclear power, whose locations are relatively concentrated in certain limited areas), rapid expansion of renewable energy power, whose locations are de-centralised nationwide, has caused many issues for the grid system, including capacity limitations. As a result, how to prevent such non-operating projects from holding up grid capacity, and how to make future investments in the grid system efficiently, were also highlighted as important issues to be resolved in connection with the FIT system.

3. **New Feed-in Tariff Act**

In response to various issues identified during the initial phase of the FIT system, in order to introduce renewable energy to the maximum extent possible while limiting the public burden, the amended Feed-in Tariff Act came into force from April 1, 2017 ("**New Feed-in Tariff Act**").

The main purposes for amending the Old Feed-in Tariff Act were: (a) to establish a new approval system where only feasible projects obtain certification and METI can effectively monitor projects on an ongoing basis; (b) to introduce additional renewable energy in a cost-efficient manner by starting an auction system for large-scale solar power generation, and to set mid- and long-term targets for the tariff; (c) to enable announcement of the multi-year tariff to encourage development of power sources with a long lead time for development, such as geothermal, wind and hydro power; and (d) to change the purchaser of electricity under the FIT system from electricity retailers to transmission and distribution business operators.

(a) **Introduction of new approval system**

Change from facility certification to business plan certification

Under the New Feed-in Tariff Act, METI will grant certifications to "business plans" (not to the facilities) ("**Business Plan Certification**") for renewable energy-based power projects. For this purpose, METI will confirm whether: (i) a business plan complies with certain prescribed standards; (ii) the contemplated business will be implemented smoothly and with certainty; and (iii) the specifications of the renewable power facility are appropriate for stable and efficient power production.

For example, in connection with (i) above, METI will confirm whether the business plan contemplates installing a system for maintenance check-ups and O&M properly, and whether the business plan includes a plan for disposal of the facility upon the end of commercial operation. In connection with (ii) above, METI will examine whether: (a) the grid connection agreement has been executed with a general transmission and distribution operator; (b) the land has been secured (or is certain to be secured) for the installation of the facility; and (c) the applicant has confirmed applicable laws and local ordinances with the relevant local government.

METI's monitoring of the Projects

Even after the Business Plan Certification is issued, METI will monitor the project on an ongoing basis to confirm whether the project is properly developed and operated pursuant to the certified business plan. If any violation is identified, METI can issue instructions or an order for improvement to a power producer, and can eventually cancel the Business Plan Certification if such power producer does not comply with the instructions or order. Note that the Agency for Natural Resources and Energy published guidelines for a business plan with respect to each category of power source (solar, wind, hydro, geothermal and biomass) in March 2017 (and revised the guidelines in April 2018) and, if power producers fail to follow the rules under the guidelines, METI may issue instructions or an order for improvement. If a power producer still fails to follow such instructions or order, the Business Plan Certification may be cancelled. Accordingly, power producers should carefully check and follow the applicable guidelines.

In fact, in January 2019, a large-scale solar power station received an improvement order from METI on the grounds of breach of a local ordinance. Further, in March 2019, the first case of cancellation of a Business Plan Certifications based on the new rules was announced in which eight Business Plan Certifications (four were under development and four were actively operating) were invalidated due to the owner's non-compliance with the laws governing use of the land.[3]

(b) **Introduction of a system to increase additional renewable energy in a cost-efficient manner**

Introduction of auction process

Under the New Feed-in Tariff Act, if an auction process is considered to be useful for decreasing the amount of the surcharge to be imposed on public consumers, METI can designate the category and the scale of power sources subject to the auction process.

The minimum size of solar power projects subject to the auction process was set as an output capacity of 2MW in 2017, and reduced to 500KW from April 2019. Certain types of biomass projects are also subject to the auction process.[4]

According to the Second Interim Report, dated January 2019 and publicised by a certain governmental special committee in charge of energy and resources, it is contemplated that the auction process: (i) will be generally introduced for all solar projects (subject to protective treatment for small-sized solar systems); and (ii) will be introduced as early as possible for wind projects, both onshore and offshore, but the auction process for small-sized solar, geothermal, mid-to small sized hydro, and small sized biomass projects should be carefully considered.

Mid- and long-term targets concerning the price level

The New Feed-in Tariff Act, with a view to decreasing the public burden by encouraging business operators' efforts and industry innovation, contemplates setting mid-and long-term targets for the price level applicable to each category of power project. The Procurement Price Calculation Committee announced the following targets for each category of power project in January 2019:

(i) Solar power:

Pursuing independence from the FIT system by achieving the following targets (accelerating the target timing in comparison to last year).

1. Non-residential use:

Power generation cost should be JPY 14 / kWh in FY 2020; and

Power generation cost should be JPY 7 / kWh in FY 2025.

2. Residential use:

Applicable tariff in FY 2025 should be equivalent to the market price in the electricity market.

(ii) Wind power:

1. Onshore wind and fixed-bottom offshore wind:

Power generation cost should be JPY 8–9 / kWh by pursuing independence from the FIT system by FY 2030.

2. Floating offshore wind:

Pursuing independence from the FIT system on a mid- and long-term basis by promoting improvement of the environment for the introduction of offshore wind power.

(iii) Geothermal power:

On a mid- and long-term basis, pursuing independence from the FIT system by reducing development risk and costs, facilitating efficiency of large-scale projects.

(iv) Mid- to small-sized hydro

On a mid- and long-term basis, pursuing independence from the FIT system by reducing costs through technical innovation, facilitating development in new places.

(v) Biomass

On a mid- and long-term basis, pursuing independence from the FIT system in collaboration with related policies.

(c) **Introduction of multi-year tariff**

Under the New Feed-in Tariff Act, it is possible to set a multi-year tariff in advance to increase foreseeability for power producers. Especially with regard to power sources requiring a long lead time (e.g. wind, geothermal, hydro and biomass), it is appropriate to set a multi-year tariff.

For example, many large-scale wind power projects and geothermal power projects are likely to trigger Environmental Impact Assessments, in which case it used to take around three to four years in total before obtaining a Facility Certification after a power producer commenced the initial step for an Environmental Impact Assessment (i.e. the process for Preliminary Environmental Impact Consideration) under the previous METI practice. Now the time period required for the whole process should be shortened, as METI has recently[5] changed its former practice and permitted applications for Facility Certification/Business Plan Certification to be accepted at an earlier stage (i.e. commencement of the Scoping Document process). After taking into account the regulatory environment as well as the necessity of coordination with local communities, METI decided to start a multi-year tariff for a period of three years in connection with large-scale wind power[6] and geothermal power projects from FY 2017. However, METI stopped determining such multi-year tariff for a period of three years in connection with fixed-bottom offshore wind in 2018 and other large-scale wind projects in 2019 taking into account, among other considerations, a high expectation of drastic cost reductions.

On the other hand, with regard to mid- to small-sized hydro and biomass, it takes around two years to obtain a Facility Certification/Business Plan Certification after a power producer starts development work. However, given the possibility of requiring a longer period for coordination with local communities and the clearance of applicable regulations, METI also announced a multi-year tariff for a period of three years in connection with mid- to small-sized hydro and biomass projects from FY 2017. However, METI stopped such multi-year tariff in connection with certain types of biomass projects from FY 2018 due to the introduction of an auction process for such projects.[7]

(d) **Change of purchaser of FIT electricity**

Under the Old Feed-in Tariff Act, the purchasers of electricity under the FIT system were electricity retailers. However, under the New Feed-in Tariff Act, the purchaser has been changed to transmission and distribution business operators.[8] In order to promote expansion of renewable energy in the future through nationwide operation of the grid system (e.g. demand and supply adjustment nationwide), transmission and distribution business operators who are responsible for operation of the grid system and demand and supply adjustment were viewed as the most appropriate parties to assume the obligation to purchase electricity generated under the FIT system. Power producers who need to enter into power purchase agreements with transmission and distribution business operators pursuant to the New Feed-in Tariff Act will enter into such agreements pursuant to the standard terms and conditions of the relevant transmission and distribution business operators.[9]

4. **Various measures targeting non-operational projects**

As discussed above, one of the issues identified during the initial phase of the FIT system was that many solar power projects obtaining Facility Certifications at the earlier stage (and therefore, qualifying for higher tariffs) had not started commercial operation after a long time. This causes two issues. Firstly, as those non-operational projects are keeping priority over grid connection rights, this may cause opportunity losses for other projects with high potential. Secondly, as those non-operational projects are qualified for a higher tariff, keeping those projects alive may prevent the introduction of additional renewable energy in a cost-efficient manner. Therefore, for the last few years, in order to reduce those non-operational projects as much as possible, METI introduced several harsh measures against non-operational projects:

(a) **Introduction of "three years rule" in August 2016**

In order to reduce the number of non-operating solar projects as much as possible, the rule setting a deadline for commercial operation was newly introduced for solar power projects with an output capacity of more than 10kW, if such solar power project entered into a grid connection agreement with the operator of the transmission line (e.g. a general transmission and distribution operator) on or after August 1, 2016. Under this new rule, if a power producer fails to commence commercial operation within three years from the date when the Business Plan Certification is granted (or from April 1, 2017 in case of a project originally having a Facility Certification and being transitioned to the new system under the New Feed-in Tariff Act), the FIT purchase period will be shortened by the number of days corresponding to the period starting after the end of such three-year period until the date of commercial operation of the project.

(b) **Transitional hurdle upon introduction of New Feed-in Tariff Act in April 2017**

When the New Feed-in Tariff Act was introduced, one of the requirements for a power producer with a Facility Certification issued under the Old Feed-in Tariff Act to keep the applicable tariff under the New Feed-in Tariff Act was that such power producer should have entered into a grid connection agreement with the operator of the transmission line (e.g. a general transmission and distribution operator) by March 31, 2017.[10] The whole purpose of requiring execution of the grid connection agreements was to prevent non-operating projects from surviving under the New Feed-in Tariff Act.[11]

(c) **Introduction of deadline for Grid Connection Work Application**

Even after the "three years rule" was introduced in August 2016, solar power projects which entered into a grid connection agreement with the operator of the transmission line before August 1, 2016 were not subject to any operation deadline and therefore, a large number of non-operational solar power projects having higher tariff (i.e. JPY40, 36 and 32 per kWh) survived with no deadline for commencing operation. Under such circumstances, in October 2018, METI suddenly proposed a new amendment targeting those non-operational solar power projects under which those projects are required to: (i) complete all major development work necessary for commencement of construction work (i.e. obtaining land use rights over all plots of land used for the project and completing all relevant permitting processes (e.g. obtaining forestry conversion permit and completing environmental impact assessment process)); and (ii) submit a Grid Connection Work Application to a general transmission and distribution operator by March 31, 2019 and if they failed to do so, those projects would suffer a material reduction of the tariff.

The reduction of the tariff has a devastating impact on those projects because lenders may no longer extend finance to projects that lose the expected margin. The purpose of the amendment was to terminate non-operational projects with higher tariffs for which no good faith attempt was made to commence operation, but because of the lack of sufficient grandfathering rules, it was expected that many large-scale projects which, by their nature, required a long preparation time, would not be able to survive the amendment regardless of whether the parties had made a good faith effort to commence operation.

In October 2018, METI sought public comments for the proposed amendments to the Ordinance. The proposed amendment encountered furious opposition from many parties, including foreign governmental bodies. The criticism was particularly focused on the retroactive application of the new rules to all non-operational and non-"three years rule" projects without reasonable safe harbours or grandfathering rules.

In response, in December 2018, METI introduced certain exceptions to the application of the new rule so as to mitigate the impact; i.e. granting certain grace periods for certain large-scale projects.

5. **Future of the FIT system**

In August 2019, METI's Advisory Committee published the Third Interim Report, which aims to reform the FIT system and even indicates an intention to modify it into a new system such as a Feed-in Premium ("**FIP**") system. News articles suggest that METI is targeting 2020 for drafting a bill to amend the FIT system.

Major developments in offshore wind power regulation

There was a major development in legislation regarding wind power systems. The main obstacles to overcome in order to develop a wind power system used to be the insufficient length and stability of land-use rights for the sites. The basic rules in Japan for the use of publicly owned land and sea provide for only 3–5 years of use rights. Such short-term use rights were not suitable for wind power projects, which will usually operate for 20–30 years.

The Ministry of Land, Infrastructure, Transport and Tourism ("**MLIT**") addressed such issues as follows:

1. **Port area offshore wind projects**

   In 2016, MLIT amended the Port and Harbor Act to extend the use right period up to 20 years for approved projects located in port areas. The projects are selected from among those publicly tendered.

2. **General water area offshore wind projects**

   In 2018 MLIT, together with METI, introduced a new law (the Act of Promoting Utilization of Sea Areas in Development of Power Generation Facilities Using Maritime Renewable Energy Resources ("**Offshore Wind Act**")), covering territorial waters outside of port areas (referred to as "general water areas"), for which an auction scheme similar to the one used for port-area wind projects will be implemented.

   Under the Offshore Wind Act, the following public selection process will take place annually and the selected projects will enjoy the benefit of long-term use rights for up to 30 years for the general water areas and the applicable tariff rates.

   (i) Local governments are requested to provide information regarding the recommended sea areas for wind projects.

   (ii) A committee (*dai-san sha iinkai*) is convened, which will review the potentially preferred areas for the project sites. The opinions of local interested parties will be taken into account in selection of the suitable areas.

   (iii) METI[12] and MLIT will first designate the potentially preferred sea areas for construction and development of wind power stations ("**Promising Areas**") and then, after a further committee consultation and certain discussion processes through the council (*kyogi kai*) established for each Promising Area and based on the results of further government-led research, designate the areas in which wind projects are supported under the Offshore Wind Act ("**Promotion Areas**").

   In July 2019, 11 potentially preferred sea areas were nominated and four of them were selected as Promising Areas. METI and MLIT will: (i) organise the council (*kyogi kai*) consisting of ministers and national government officers as well as local governors and local interested parties in each area and have them reach a consensus; (ii) conduct wind-condition and geological research; and (iii) have the committee (*dai-san sha iinkai*) review and provide opinions after consulting with local interested parties. METI and MLIT will finally designate seven Promotion Areas (targeting the end of 2019). The entire process to select and announce the Promotion Areas is expected to take at least 10 months and will be repeated annually.

   After the designated Promotion Areas are announced, the government will conduct a public tender process for the selection of operators for wind power facilities. Potential operators will be required to submit a detailed business plan as part of the bidding process and one operator per Promotion Area will be appointed to proceed with the project. Operators may be required to have a business office in Japan, similar to the public tender process for projects in port areas.

   Because the government will take the opinions of local stakeholders, including local governments, into consideration when reviewing bids, it will be important for interested operators to begin discussions with the local government and other stakeholders (such as fisheries) well in advance. A business plan, clearly setting out terms agreed with local stakeholders, is likely to lend a significantly higher chance of selection.

Although the Offshore Wind Act is a significant step toward development of large-scale offshore wind power in Japan, certain difficulties remain which may raise challenges for bankability and development, including: (i) an inability to create a security interest over the use rights for sea areas; and (ii) expected difficulty in ensuring grid connection at a reasonable cost. It also remains to be seen how quickly the Environmental Impact Assessment process can be completed for offshore wind projects under the Offshore Wind Act.

* * *

Endnotes

1. In fact, it was reported that as of August 2019, only nine nuclear power plants have resumed operation. Fifteen nuclear power plants have obtained permits to resume operation under the new regulatory standards but six of those nuclear power plants are not operating because of delayed construction for safety confirmation and opposition from neighbours. Applications by 10 other stations to resume operation are under review by the Nuclear Regulation Authority, but four operating stations are expected to lose their permits in 2020 because of delays of construction of counter-terrorism facilities.
2. A "grid connection agreement" comprises an agreement to interconnect with the grid point and an agreement to bear the construction costs required for the construction conducted by the operator of the transmission line.
3. The business owner failed to get an approval necessary to set up the solar power station on the site under the Agricultural Land Act and Act on Establishment of Agricultural Promotion Areas.
4. General wood biomass having an output capacity of 10 MW or more, and liquid biomass fuel power systems (irrespective of the size of the project).
5. METI announced this new practice on December 5, 2016.
6. Small-scale wind power projects with a capacity of less than 20 kW are excluded.
7. General wood biomass having an output capacity of 10 MW or more, and liquid biomass fuel power systems (irrespective of the size of the project).
8. Provided that power producers who entered into power purchase agreements with electricity retailers prior to the change can keep such agreements even under the New Feed-in Tariff Act.
9. As a result, the METI form of power purchase agreement was abolished.
10. There are two exceptions to the deadline for entering into a grid connection agreement. First, if a power producer obtained its Facility Certification after July 1, 2016, the deadline would be nine months from the date of such Facility Certification. Second, in the case that a power producer participates in an auction process for certain joint enhancement construction projects related to the grid system and/or facilities thereof, such power producer shall enter into the grid connection agreement within six months after the auction process is completed, and the deadline for submission of its business

plan is six months after the grid connection agreement is executed.

11. Once the grid connection agreement is executed, a power producer owes an obligation to bear a certain part of the construction cost required for the construction conducted by the operator of the transmission line. Accordingly, it seems that many non-operating solar projects with low feasibility of successful completion of development abandoned entering into grid connection agreements before March 31, 2017 and therefore their Facility Certifications should have been cancelled.
12. In practice, the process is led by the Agency for Natural Resources and Energy ("ANRE"), an agency associated with METI.

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Overview of the current energy mix and different energy sources

South Korea has maintained its energy generation mainly from fossil fuels and nuclear power, currently accounting for approximately 70% of its energy mix.[1] With an intention to reduce its energy reliance on traditional sources, the South Korean government (hereinafter referred to as the "**Government**") has focused on developing two fundamental aspects related to its the energy mix, namely: (i) a reduction in the use of both fossil fuels and nuclear energy for power generation; and (ii) the conversion of those current primary energy sources into new and renewable energy sources. The Government has established several energy policies collectively centering on a steady supply of energy, environmental-friendly energy systems, and energy security.

The Government has aimed at accelerating the use of new and renewable energies while seeking the harmonisation of environmental and safety factors in order to achieve energy supply stabilisation. The Government's energy agenda has focused on phasing out its traditional coal and nuclear power generation facilities, to be replaced by new and renewable energy sources. However, there is a growing concern over electricity supply shortages during this energy supply transition, in particular because the installation of new and renewable energy sources might not be concluded in time to offset the anticipated electricity shortages, due to the phasing-out of traditional coal and nuclear power generation facilities.

In light of the foregoing, this article will first introduce the Government's movement in the last 12 months towards a new energy mix and the introduction of its energy policies, and consider the relevant implications for the growing energy supply concerns as well as possible solutions thereto.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In the global energy market, the proportion of fossil fuels and nuclear energy are currently in decline as the proportion of eco-friendly energy sources is conversely increasing. In this regard, South Korea could be considered "a leading player in the floating energy space",[2] as the country has announced public plans to construct one of the largest new and renewable clusters in the world – a massive 4GW complex off its west coast. With that said, however, contrary to global trends and the aforementioned project, the South Korean energy mix depends on conventional thermal energy sources rather than new and renewable energies as reflected in the electricity production comparison chart[3] overleaf:

Electricity Production Percentage by Fuel Types[4]

Fuel Type	OECD Total		South Korea	
	2019 (%)	2018 (%)	2019 (%)	2018 (%)
Coal	22.3	25.3	39.9	44.8
Natural Gas	27.0	27.4	24.8	25.1
Nuclear	18.6	17.5	28.2	22.8
Hydro	14.4	13.9	1.2	1.3
Wind	8.5	6.9	0.4	0.4
Solar	3.2	3.0	1.8	1.6
Others	6.0	6.0	3.7	4.0

Compared to the production mix of the OECD countries in total, the South Korean index indicates its excessive dependence on coal and nuclear energy, still accounting for nearly 70% of its energy mix in 2019. However, the combination of hydro, wind, and solar energy (i.e., typical new and renewable energy sources) only constitutes 3.4% of its electricity production, despite the Government's environmentally friendly policies in this regard.

What is the most noteworthy from the above figures is the South Korean expansion of nuclear power generation, which seems contrary to the Government's nuclear energy 'phase-out policy'. The Government has strongly enforced its plans to limit and reduce nuclear power generation by shutting down certain aging plants without considering any further extensions, as well as cancelling all new nuclear power plant construction plans. However, in 2019 the nuclear energy mix in South Korean significantly increased: up to 28.2%, from 22.8% in 2018. The foregoing phenomenon indicates that South Korea may need a certain period to complete a successful transition or conversion of its energy mix to new and renewable energy sources.

Considering the foregoing, it is incumbent upon the Government to provide policies and strategies to properly cope with the anticipated reduction of energy generation overall; and in this regard we would like to introduce in the rest of this chapter, the Government's policies and approaches towards a new energy mix based on the expansion of new and renewable energy sources, and the legal implications arising therefrom.

Developments in government policy/strategy/approaches and corresponding legislation or regulations

Review: The 8th Electricity Supply-Demand Basic Plan

Within the Government, the Minister of Trade, Industry and Energy (the "**MOTIE**") is required to formulate a basic plan for electricity supply and demand (the "**Electricity Supply-Demand Basic Plan**" or the "**Basic Plan**"), in accordance with those requirements as specified in the Electric Utility Act (the "**EUA**"). In particular, Article 3 of the EUA reads that "the Minister of Trade, Industry and Energy shall prepare fundamental and comprehensive policies for the stable supply and demand of electricity, the promotion of competitiveness in the electric power industry, and the like." As a result, in 2018 the MOTIE announced its 8th Basic Plan for the efficient use of energy, environmental protection, and public safety. The 8th Basic Plan consists of three major objectives, namely: (i) the expansion of new and renewable energy to eventually replace coal and nuclear energy; (ii) a new energy mix in compliance with environmental and safety standards; and (iii) the fulfilment of demand-side management.

1. **Expansion of new and renewable energy to replace coal and nuclear energy**

   In the Government's 'New and Renewable Energy Plan 3020', South Korea defined its objective to eventually expand new and renewable energy sources up to 20% by 2030. The Government disclosed its intention to increase the electricity supply generated from new and renewable energy sources by 58.5 GW – until 2030.[5] However, as the Government has already cancelled construction plans for six nuclear plants, as well as promised the shutdown of a further 10 aging nuclear generation facilities and 10 coal power plants without further operational extensions, there is growing concern about such drastic reductions possibly leading to supply shortages of electricity, as the renewable energy industry must inevitably undergo a certain period of stagnation due to its relatively expensive cost of installation.

2. **The new energy mix: in compliance with environmental and safety standards**

   The 8th Basic Plan is aimed at eventually ensuring environmental and safety standards which inflict zero harm to the environment. In this regard, the Government has enforced a policy to reinforce emission standards by imposing strict restrictions on coal power plant operation in order to protect air quality, in accordance with the Clean Air Conservation Act. In addition, the Government has been forcibly restricting coal power generation particularly during the spring, when fine dust especially pervades the atmosphere in South Korea.

   Also, to effectively and safely cope with decommissioning nuclear power plants, the Government proclaimed the new Nuclear Safety Act (the "**NSA**") to regulate the safety of nuclear energy development and use. The NSA was established to provide for matters concerning safety management in order to ensure the prevention of environmental disasters resulting from any radiation leakage occurring while dismantling nuclear power plants in the future.[6]

3. **Fulfilment of demand-side management**

   The Government has announced various measures to be taken in the long-term to reduce total electric power generation by 12.3%, and total power consumption by 14.5%, by 2030.[7] To fulfil such demand adjustment and the management of same, the Government has implemented: (i) new types of electric energy businesses; (ii) the Demand Response (the "**DR**") system; and (iii) the Energy Efficiency Resource Standards (the "**EERS**") and the 'Energy Champion System'.

   (i) **DR system**: If a company uses less electricity than its current consumption amount, then the remaining amount of electricity will be sold to KEPCO, and the company and the relevant demand-management company will share the proceeds.

   (ii) **EERS**: These are certain standards intended to encourage reductions in energy usage, in the form of a self-regulating system for energy suppliers, in order to control demand-side management in the long term. In exchange for the system's operation, the Government grants rewards to those energy suppliers who actively cooperate with the Government's demand-side management measures – the so-called Energy Champion System.

   With such initiatives, the new and renewable energy market is expected not only to expand in terms of its size, but also to diversify supply and energy generation methods in the future.

4. **Sub-conclusion**

   The Government proclaimed the 8th Basic Plan – which is relatively abstract conceptually – not only to ensure compliance with the EUA requirements in principle, but also to set policies leading to considerable growth in the new and renewable energy sectors in the long term. As a result, the Government unveiled its advanced strategy in the form of its "Reinforcement of Renewable Energy Competitiveness", and its "3rd National Energy Roadmap" plans and policies.

Reinforcement of Renewable Energy Competitiveness[8]

1. **Purpose: to expand investments into the new and renewable energy market**

   In April 2019, the Government published its "Reinforcement of Renewable Energy Competitiveness" plan (the "**Reinforcement Plan**"), to secure successful energy conversion and to expand new and renewable energy investments, and thereby to spur the creation of various new jobs and expedite its energy-export industrialisation strategy.[9]

   The Reinforcement Plan is purposely established to accelerate the New and Renewable Energy Plan 3020. More specifically, as the New and Renewable Energy Plan 3020 targets that more than 95% of new power generation capacity shall be supplied by clean energy sources such as solar power (63%) and wind power (34%), and the targeted amount provided by these energy sources will be 12.4 GW each year in the earlier stages (years 2018–2022), and 36.3 GW each year in the later stages (years 2023–30),[10] the Reinforcement Plan is intended to promote the expansion of private investments by inducing the replacement of aging facilities with high-efficiency facilities and laying the foundation for the implementation of 'RE100' – a 'campaign' aimed at eventually achieving power generation capabilities entirely with new and renewable energy sources.

2. **Efforts to develop investments**

   In order to develop and vitalise investments into the new and renewable energy market, the Reinforcement Plan has introduced the system of "Certificates of Carbon Emission" to grant economic benefits to companies equipped with low-carbon emission facilities over their entire production cycle, including transportation, installation, and dismantling of facilities, and the like. The foregoing certificate system will be provided based on minimum efficiency standards set by the Government, to be used as a guideline for such grant.

   In addition, the Reinforcement Plan may complement the advance of new types of energy business models such as in the ICT (Information and Communications Technologies) industry. For instance, the ICT industry will be utilised not only to produce renewable energy products in a more efficient and economical way, thereby creating a new and renewable energy industry after convergence with high technology (e.g., smart factories). To promote the foregoing, the Government plans to establish a one-stop integrated supporting system to resolve legal matters such as licensing and licensing procedures so as to lower the barriers to entry and to encourage more companies to enter into the new and renewable energy market through the Reinforcement Plan.

3. **The Government's plans regarding the investments under the Reinforcement Plan**

   As a part of the Reinforcement Plan, the Government has publicly announced that it would promote an investment fund of up to KRW 500 billion (approximately US$ 420 million) for developing new and renewable energy production facilities. The fund will be used for such projects as the construction of smart factories, or the restructuring of eco-friendly companies.

Moreover, in order to promote the overseas expansion of South Korean energy companies, the Government has prepared plans to reduce overseas insurance rates by approximately 10% if these companies receive and operate overseas projects related to energy sources. The Government may also use some portion of the investment funds to establish a "Committee for Joint Energy-Export Expansion" in order to facilitate multi-party cooperation among energy companies and manufacturing companies, in order to foster and harness synergistic effects.

The 3rd National Energy Roadmap[11]

1. **Basic rationale of the 3rd National Energy Roadmap**

   The 3rd National Energy Roadmap (the "**Roadmap**") concentrates on strengthening South Korea's global competitiveness in the energy industry by ensuring a successful conversion to its desired new energy mix based on eco-friendly and safety-guaranteed conditions. In June 2019, the Roadmap was announced based on Article 41 of Framework Act on Low Carbon, Green Growth (the "**Framework Act**"), that the Government would be obligated to produce a basic plan for energy every five years, for a planning period of 20 years. Such plan must be in accordance with the basic principles for energy policy, including matters related to: trends and prospects of domestic and overseas energy supply and demand; measures for securing stable supply; the import, supply, and management of energy; the supply and use of environmentally friendly energy; and measures for the safety control of energy.

   Considering the foregoing, the basic rationale for the Roadmap is to successfully increase energy generation rates for new and renewable energy by up to 35%, in response to the coal and nuclear power phase-out.

2. **Objectives of the Roadmap and related policy suggestions**

   The Roadmap suggests an energy policy related to the successful transition of the energy consumption structure to more efficient new and renewable energy sources. With conspicuous improvements in energy efficiency, the Roadmap proposes the reduction of the final energy consumption by 18.6% by year 2040.

   In order to achieve the foregoing objective, the Roadmap also contains plans to develop and provide high-efficiency devices, eco-friendly vehicles, and facilities to various energy corporations. The development and provision of such items will operate through the efficient Energy Management System (EMS), which will function as a kind of 'control tower'. In this regard, the Roadmap may expand business opportunities for Energy Service Companies (ESCOs), by encouraging more ESCOs to use the efficient new and renewable energy-related devices, vehicles, and facilities, and contribute to successful migration to the energy-policy paradigm.

   Lastly, the Roadmap describes its plans to establish a more equally distributed power generation system and to reduce discrimination in the energy supply. The Government has revealed its plan to minimise disparities in power self-sufficiency across provinces, by promoting a more integrated operational system based on new and renewable energy sources. The Roadmap states that this plan could be actualised with the provision of a so-called "Advanced Metering Infrastructure", which will facilitate remote meter reading services for every province in South Korea. More specific plans will be provided through the "Long-Term Energy Distribution Roadmap", scheduled to be released in 2020.

3. **Fund management to enforce the Roadmap**

   The Roadmap includes detailed plans to allocate energy funds as follows: KRW 257 billion (approximately US$ 200 million) to be used for Renewable Energy Loans; KRW 100 billion (approximately US$ 80 million) to be used for the Mutual Guarantee Fund (for mid-sized new and renewable energy companies); and KRW 150 billion (approximately US$ 120 million) to be used for the New and Renewable Plant and Equipment Guarantee Fund.

The Government has also announced plans to establish a general energy fund of KRW 100 billion for M&A projects, restructuring, or scale-up of new and renewable energy companies. The Roadmap also briefly introduces the concept of the "R&D Road", which will be published in late 2019, in order to provide a blueprint for technical development in the energy industry.

Implications of the Government's current policies

As discussed above, Article 25(1) of EUA and Article 4(2) of its Enforcement Decree stipulates that "the Minister of Trade, Industry and Energy shall formulate a master plan for electricity supply and demand to stabilise the supply and demand of electricity", and also that "the energy business shall be permitted to operate on the basis of the master plan by MOTIE."

There is ongoing social debate surrounding the validity of the Government's electricity supply and demand plans. In the end, the decline in energy supply caused by the phase-out policies affecting nuclear power and coal plants will likely far exceed the increase in supply from the expansion of new and renewable energy sources.[12] For instance, by 2030 the revocation of construction plans for six nuclear power plants, and the shutdowns of 10 aging nuclear generation facilities, may lead to an 18 GW reduction in total energy production. Also, the shutdown of 10 coal power plants may result in a 3 GW reduction. On the other hand, however, it is anticipated that the energy increase from expansion into new and renewable energy sources will not exceed 8 GW.

According to the "2018 Statistics of Energy Market", the maximum capacity of electric power supply reached its apex in 2018, and has consistently decreased since then.[13] The energy supply trends in South Korea clearly indicate that there should be proper administrative or legislative measures to mitigate or adjust the Government's nuclear and coal phase-out policies, in order to maintain energy stability, and to avoid the real prospect of power supply shortages.

Major events and developments

Continuous concerns over denuclearisation energy policy

As mentioned above, the phase-out plan for nuclear power plants has been delineated as follows: (i) all six new construction plans will be cancelled; and (ii) all 10 aging nuclear plants will be shut down within the next decade (i.e., no renovations or extensions of those facilities are scheduled). The Government in the meantime encourages nuclear power companies not only to spread their nuclear energy technology by exporting to overseas markets, but also to maintain their priority position in the nuclear decommissioning market.

Nuclear power plants require high initial investment costs but afterwards have low operating costs. This means that, once the construction of such plants is complete, it would be more beneficial to operate the same for as long a time as possible, in consideration of the tremendous investment originally put into building such plants. In this regard, the Government's denuclearisation energy policy, without any compensatory measures for companies operating nuclear power plants or related businesses, may be interpreted as violating the constitutional principle of proportionality and the protection of property rights for such private entities.

With regard to the foregoing dispute, it would be highly relevant to refer to and highlight similar court cases from Germany.[14] In 2012, following the Fukushima disaster, the German government decided to shut down all nuclear plants by 2022, and various energy companies in Germany raised constitutional and administrative lawsuits against the German government for unjustifiably causing costs of decommissioning to be incurred as well as damages from the unexpected shutdown of their nuclear operations. On December 5, 2016, the Federal Constitutional Court (*Bundesverfassungsgericht*) ruled that nuclear plant operators (E.ON, RWE, and Vattenfall) affected by the phase-out of nuclear power were eligible for adequate compensation, since these companies were entitled to damages for their investments made in 2010.[15] In addition, the court compelled the German government to enact new rules regarding such compensation. The local press estimated that the damages amounted to up to €19 billion in total.

The aforementioned German case reveals another facet of the nuclear phase-out policy, namely financial compensation for damages incurred. The drastic phase-out policy may possibly raise civil claims in relation to compensation matters in South Korea, which could then hinder or obstruct the fulfilment of the Government's energy plans as originally scheduled. In this regard, the Government may take preliminary actions such as legislative measures to enact new rules and regulations while proceeding with its policies, in order to minimise confusion and increase confidence among those parties involved in the nuclear power industry.

<u>Debate or dispute over the Basic Plan and the Roadmap</u>

There have also been ongoing debates regarding possible illegalities in the 8th Basic Plan as well as the Roadmap, as administrative plans. In particular, it has been argued that the foregoing have not been fully subjected to the deliberative policy-making process among the interested parties. As to the legal effects of the Basic Plan and the Roadmap, however, the Ministry of Government Legislation has provided an authoritative interpretation, as follows:

> *"The basic plan for electricity supply and demand is a statutory plan established and finalised under Article 25(2) of the EUA and the collection of opinions through public hearings as well... (omitted) ...If the contents are disclosed and notified externally, all national agencies are legally bound to same."*[16]

The interpretation clearly states that the 8th Basic Plan and the Roadmap carry legally binding force and effect on all interested parties involved with the various energy sources. Therefore, those whose exercise of their own property rights have been infringed or curtailed may be able to file civil or administrative claims against the Government for any of its legally binding energy policies which subsequently cause them to incur any loss or damages.

In order to properly avoid or manage the foregoing legal dispute, it appears that the Government should enact new laws and regulations or otherwise undertake legislative procedures to set guidelines for its energy policies. In addition, it may be also necessary for the Government to proceed with deliberative public hearings, not only to widely inform the public of its energy policies but also to ultimately avoid unnecessary legal disputes arising from any losses and damages incurred.

Development of electricity rate system

In South Korea, the electricity rate system consists of three different categories, namely: industrial use, general use, and household use. The rates are composed of two-part tariffs – with basic rates (minimum rates) and rates based on the amount of electricity actually used. The excessively burdensome rates being imposed only on household electricity use are together called the 'progressive billing system', and have been designed to encourage frugal energy consumption among household consumers by charging higher rates for higher electricity use.

The progressive billing system is composed of a three-stage progressive rate structure, creating payment differences in electricity rates. However, the controversy arising from this billing system is that it only applies to household electricity rates, imposing burdens on household electricity use. In 2018, the Government temporarily adjusted the system in July and August for two months (only), but since then the Government announced its plans to use the adjusted billing system in July and August of every year. The adjusted billing system may be calculated based on the following:

Cost per kWh	Before Adjustment	After Adjustment
First Stage (KRW 93.3)	0~200 kWh	0~300 kWh
Second Stage (KRW 187.9)	201~400 kWh	301~450 kWh
Third Stage (KRW 280.6)	Above 401 kWh	Above 451 kWh

The progressive electricity billing system has become one of the major social issues in South Korea, as it directly affects people's household budgets. The adjustment of the billing system is expected to reduce household electricity rates by 16 to 18%,[17] but this cannot be the ultimate resolution to stabilise the billing system *per se*.

In past years, some plaintiffs (ordinary citizens affected by the progressive billing system) have claimed the return of unjust gains received by KEPCO (the Korea Electric Power Corporation) under the progressive electricity billing system, which should be invalidated in accordance with Article 6 of the Act on the Regulation of Standardised Terms and Conditions, which stipulates that "any clause in any standard terms and conditions which is not fair or contrary to the principles of trust and good faith shall be null and void."

The most recent case judgment rendered on July 2, 2019 stated that "the current progressive billing system for electricity use is made necessary on the basis of social policy needs rather than for the benefit of KEPCO."[18] In this regard, the court confirmed that, given the limited supply of electricity, it is not unfair for those who use considerably more electricity than others to pay higher unit prices per electricity use.

With that said, however, the MOTIE and KEPCO together have recently launched the "Task Force on Electricity Progressive Billing System" in order to amend the progressive system in favour of citizens' needs. KEPCO will proceed with a more detailed survey on the relation between citizens' income and their electricity consumption as preliminary preparation for a rational reform plan by the first half of 2020. As such, the Government is now in the process of implementing more detailed plans to satisfy household consumers with a fair and reasonable electricity rate system.

Conclusion

Since 2017, when the 8th Basic Plan was first announced as a foundation policy for stable electricity supply and demand under the new energy mix, the Government has been putting significant efforts towards securing both environmentally safe and economically efficient energy sources for the long-term. As a result, the Government has established the

Reinforcement Plan and the Roadmap in order to promote financial investments and technology development plans for improving the quality of the new energy mix.

It is true that there are growing concerns over the likelihood of supply shortages of electricity during the energy mix transition coupled with the nuclear and coal power phase-out, currently accounting for 70% of the energy mix in Korea. In this regard, it would be preferable for the Government to take preliminary measures – either legislative or administrative actions – to facilitate energy supply stability and to avoid any mismatch and confusion arising from this energy mix transition. In order to achieve the smooth transition of the energy mix, the Government will certainly have to improve the quality of new and renewable energy sources through constant innovation; at the same time, however, it will also have to be able to control nuclear and coal power generation in order to fulfil energy demand without any supply shortages, all the while protecting the environment and public safety.

* * *

Endnotes

1. Monthly Electricity Statistics, the International Energy Agency, May 2019.
2. Renewable Energy Country Attractiveness Index, Ernst & Young LLP, May 2019.
3. This comparison chart has been prepared based on the current year-to-date electricity production until May 2019 (the most current information disclosed so far), vs. the total electricity production for year 2018, by the International Energy Agency.
4. "OECD Total", Monthly Electricity Statistics, the International Energy Agency, May 2019.
5. "The 8th Electricity Supply-Demand Basic Plan," MOTIE, December 2017.
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Mozambique

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Despite Mozambique's wealth and diversity in natural resources, the country remains nonetheless significantly dependent on hydro resources for energy generation. Recently, however, Mozambique has diversified its primary sources of power generation by taking advantage of the recent discovery of natural gas in the Rovuma Basin and promoted the development of gas-to-power projects, as well as setting ambitious goals for the implementation of renewable projects in the coming years.

Overview of the current energy mix, and the place in the market of different energy sources

<u>Hydro</u>

Mozambique's power generation remains highly dependent on hydroelectric power plants, this source of energy representing over 90% of total primary energy supply.

The Cahora Bassa hydroelectric power plant ("**HCB**"), located in the central region of Mozambique (at the Zambezi River) with a capacity of 2,075 MW is the largest hydroplant in the country. Other major hydroelectric power plants, such as the Chicamba and Mavuzi power plants (96 MW) and Corumane powerplant, in Maputo province (16.6 MW) also contribute to the significant share of hydro generation referred to above.

<u>Natural gas</u>

One of the biggest developments in the last decade in terms of energy source is the implementation of large-sized natural gas powerplants.

Indeed, the production of natural gas in Mozambique has grown by 5.3% per year on average since 2004. Such energy is also exported to neighbouring countries, especially to South Africa with whom Mozambique has entered into energy supply agreements.

Mozambique has implemented three principal natural gas power plants pursuant to a public-private partnership model which sell all of the energy generated to Eletricidade de Moçambique ("**EDM**"): the thermal powerplant of Ressano Garcia ("**CTRG**") (175 MW); the thermal powerplant of Gigawatt (120 MW); and the thermal powerplant of Kuvaninga (40 MW).

The Temane Thermal Power Plant with an installed capacity of 400 MW is now expected to be constructed, as financing for the transmission line project from Temane to Maputo has been secured. In addition, and pursuant to a tender launched by Government of Mozambique for the award of gas in the Rovuma Basin, a 250 MW CCGT is also expected to be developed near Nacala.

In light of the above, despite hydropower's historical dominance, the trend is clearly changing and natural gas power plants are increasingly gaining relevance in the generation mix.

Renewables

With the lack of grid infrastructures, domestic consumption in most rural areas is mainly based on the burning of biomass (charcoal and fuelwood). This circumstance is naturally seen as unsustainable from an environmental angle and is pushing the Government to further the development of off-grid renewable projects that may respond to decentralised consumption demand.

On solar capacity, Mozambique has grown from 1 MW in 2011 to 15 MW in 2017, but this still represents a rather small contribution to the overall supply, especially considering the country's high potential on solar radiation. Two photovoltaic power plants of 41 MW each are being implemented – the PV power plant of Mocuba and the PV power plant of Metoro.

As far as wind generation is concerned, EDM and some promoters have initiated viability studies in several locations with renewable energy potential, namely three windfarms in Namaacha, Manhiça and Cahora Bassa (each with 30 MW).

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Gas-to-power projects

Although the Mozambique energy landscape has been swiftly changing in the past decade, the recent discovery of a reserve of 127,400 of cubic metres of natural gas in the Rovuma Basin in the Province of Cabo Delgado will undoubtedly be the cornerstone of the energy future in Mozambique. This is considered to be the fourth-largest natural gas reserve in the world and a major opportunity for exporting liquefied natural gas and installing and exploring large-scale power plants in Mozambique.

The Government of Mozambique has launched a tender for the allocation of gas from the Rovuma Basin and approved the implementation of a 250 MW gas-fired power plant and related infrastructure.

Renewable projects

The Mozambican Government – through the Fundo Nacional de Energia ("**FUNAE**") – recently published the Renewable Energy Atlas of Mozambique (the "**ATLAS**") to identify the opportunities for the development of renewable projects in the country.

The ATLAS shows an overall potential for renewable resources of 23,026 GW driven by solar sources (23,000 GW), followed by hydro (19 GW), wind (5 GW), biomass (2 GW) and geothermal (0.1 GW). The ATLAS identified 189 locations for grid-connected power plants with a total capacity of 599 MW. This potential offers opportunities for both grid-connected and rural electrification (microgrid or off-grid) projects and will lead to a major development in renewable energy projects.

Developments in government policy/strategy/approach

Government of Mozambique and EDM Master Plan 2018–2043

In January 2019, the Mozambican Government approved an "Integrated Electricity Master Plan 2018–2043" with the purpose of increasing the country's capacity to generate, consume and export electricity.

In accordance with the Government of Mozambique, in order to respond to the demand for energy, the country would require the installation of approximately 100 MW of new capacity per year. In this respect, it is worth noting that the Government of Mozambique and EDM are establishing several partnerships for the purposes of developing sustainable projects.

At the same time, EDM published its strategy for the years 2018–2028, aiming to support and lead the initiative of the government. In its strategic plan, EDM highlighted the need to integrate renewables with the national grid and develop commercial off-grid systems for remote areas.

The plan envisages an energy demand of approximately 8,000 MW (10 times higher than current demand). To respond to such increase in demand, a significant increase of installed capacity is foreseen, with diversified sources: (i) 4,300 of hydro; (ii) 1,350 MW of coal; (iii) 530 MW of solar; (iv) 150 MW of wind; and (v) 8,500 MW of natural gas.

Despite the above, the country is significantly deficient in electrification infrastructure, for which investment in transmission and distribution networks is essential. The Government plans to construct 400 KV transmission lines for connecting the south, centre and north of the country, especially in order to complete the transmission line between Cataxa-Tete and Maputo. According to the Government's plan, the above would allow universal energy access to be achieved by 2030.

In August 2019, several financing contracts were executed between the Government of Mozambique and foreign institutions (such as the Government of Norway, the World Bank, the African Development Bank, the Islamic Development Bank, the Organisation of Petroleum Exporting Countries Fund and the Southern African Development Bank) for the construction of a 563-kilometre electricity transmission line between Temane and Maputo. The construction is scheduled to start in the first half of 2020 and due for completion by the end of 2023.

According to the Government strategy, the construction of the Temane-Maputo line is the first phase in creating the "backbone" of the country, which will allow the development of integrated electrical infrastructures and therefore electrification of Mozambique and Southern Africa.

Developments in legislation or regulation

<u>Overview of the applicable framework in the energy sector (in particular, for the implementation of projects in Mozambique)</u>

The Electricity Law (Law 21/1997 of 1 October) was approved in 1997 and governs the licensing of power projects and power-related activities production, transmission, distribution, trading and import and export of electricity in Mozambique. It aimed to open the Energy Sector to private investors through the establishment of concession contracts, to be executed between the Project Company and the Government of Mozambique, which is represented by the Ministry of Mineral Resources and Energy ("MIREME"), as well as the execution of PPAs (Power Purchase Agreements) with the EDM.

The Electricity Law provides that projects related to the generation, transportation, distribution and trading of electric power as well as the construction, operation and management of electrical installations (other than generation of electric power for own consumption) are subject to a concession to be awarded through a competitive public tender. Concessions are limited to 50 years for hydropower projects and 25 years for all other technologies.

Considering that most projects are built under the PPP model, projects in the Energy Sector shall also be governed by the PPP Law (Law No 15/2011 of 10 August).

On the other hand, as regards generation licensing, we would like to highlight that the framework is demarcated by several separate laws and decrees, as follows:

(i) the Regulation on the Authority and Procedures for the Distribution and Trading of Electric Power (Decree 8/2000 of 20 April);

(ii) the Regulations on the Rules for the Construction and Maintenance of Electrical Installations (Decree 42/2005 of 29 November);

(iii) the Regulations on Licences for the Establishment and Operation of Electrical Installations (Decree 28/2007 of 22 October), which foresees the procedure for obtaining generation licences; and

(iv) the Electricity Facilities Licensing Regulation (Decree 10/2016 of 25 April), which establishes the licensing procedures that must be followed for each of the above activities. The Electricity Facilities Licensing Regulation divides the type of 'facilities' that are involved in electricity generation, transmission and distribution into ten categories, with each category having to follow a particular licensing procedure.

Apart from the Energy Sector-specific laws, please bear in mind that the implementation of energy projects in Mozambique is also highly dependent on title for the use of land. Land Law (Law 19/97 of 1 October) foresees that land, and its associate resources, are owned by the State and cannot be sold or otherwise disposed of or encumbered/mortgaged. The Land Law, however, grants private persons and entities the right to use and enjoy the land known as "*Direito do Uso e Aproveitamento da Terra*" ("**DUAT**").

Lastly, it is worth mentioning that a foreign investor may make an application for an 'investment certificate' for a particular project which will grant it certain incentives and benefits. However, for such a project to be eligible should ensure a foreign investment of a minimum of MT 2,500,000 (USD 40,170) and the application for such investment certificate shall be made by a company with a registered office or registered branch in Mozambique.

Relevant authorities

MIREME is the key entity within the Government of Mozambique responsible for the energy sector and thus responsible for the analysis, preparation, formulation and implementation of energy policies, as well as for promoting and approving projects of electric power supply. The National Directorate of Energy ("**DNE**") is the executive body within MIREME and a key player in all phases of the project, notably, during the negotiation of the Project Agreements as well as for licensing purposes and others. DNE is responsible for implementing and executing the competences of MIREME in the electric power sector, with the exception of the setting of tariffs and rural electrification which are under the jurisdiction of ARENE (see below) and FUNAE respectively.

The Autoridade Reguladora da Energia ("**ARENE**") – whose organic statute has been approved in 2019 – is the entity responsible to instruct and monitor the public tender procedures for the award of concessions for production, transmission, distribution and sale of electricity and for the approval of regulated tariffs.

Lastly, Electricidade de Mocambique ("**EDM**") is a state-owned and vertically integrated utility that is responsible for the generation, procurement, transmission, distribution and sale of electricity. EDM is the offtaker of power projects developed in the country.

Review of regulatory framework

The regulatory framework briefly described above is under revision, with the support of the United States Agency for International Development ("**USAID**"). In accordance with the information publicly available, the revision of the Electricity Law aims to improve market conditions in the country, providing adequate legal guarantees for investors in the energy sector. The current Electricity Law regulates mainly utility-scale projects and in order to reach the objectives of the EDM's Integrated Master Plan, the new law seeks to simplify authorisation procedures for mini-grid projects, which are seen as a priority to increase electricity access in remote areas.

According to the Government's projects, the new regulatory framework also aims to simplify the permitting and licensing framework, by establishing three different kinds of authorisations: concession, licence and simplified licence. The permits will vary according to the size of the project and the type of natural resources involved.

Lastly, the role of EDM is perceived by some investors as restricting the private initiative and investment and therefore, the new regulatory framework is also expected to enable participation between both EDM and private investors.

Judicial decisions, court judgments, results of public enquiries

To be best of our knowledge there is no available case law, judicial decisions, court judgments or results of public enquiries in Mozambique on the interpretation and application of the relevant legislation of the Energy Sector.

Mozambique often refers to Portuguese court decisions, but in the Energy Sector, no court decisions have (to be best of our knowledge) been issued in Mozambique.

Major events or developments

Foreign investment and partnerships with European and international agencies for the promotion of new power projects are increasing year-on-year, however some programmes under development are more likely to impact legislation and the creation of new projects, as better detailed below.

PROLER programme

The Project to Promote Auctions for Renewable Energies ("**PROLER**") was launched by the European Union, through the EU Trust Fund for Africa together with Agence Française du Développement ("**AFD**") and EDM. This project, which aims to identify areas to be electrified, launches a public tender to award contractors based on technical and financial criteria, and assists EDM in electrification development, as well as providing financial and technical support to EDM. So far, the PROLER programme has launched four tenders for the implementation and development of three solar and one wind project, of 30 MW each, by 2021.

GET FiT – Global energy transfer feed-in tariff / REFiT Programmes

KfW Development Bank (German Government-owned development bank), along with other stakeholders, has developed the Global Energy Transfer Feed in Tariff ("**GET FiT**") Programme. The GET FiT Programme aims to fast-track the development of smaller renewable energy generation projects through a comprehensive set of tools, including tariff viability gap funding, targeted technical assistance, risk mitigation against off-taker risk, and renewable grid integration support. The same programme is active in other Sub-Saharan

African countries, such as Uganda (where it has successfully promoted a combined portfolio of 170 MW of smaller renewable energy generation projects), Zambia, Malawi and Namibia.

Similarly, the Government of the Republic of Mozambique, represented by MIREME, introduced a Renewable Energy Feed-in Tariff ("**REFiT**") Regulation in 2014, in order to promote private investments in the Mozambican energy sector. However, this Regulation was valid for a period of three years only and the administrative procedures were never approved, therefore, no investment was done under such programme.

Further to such developments, KfW and MIREME initiated discussions in 2014 with a view to develop a GET FiT Programme for Mozambique in support of GoM's REFiT Regulation.

In April 2019, KfW assessed the implementation of the programme and set forth that the same is to be launched in the beginning of 2020. The viability study underlying this programme evidences the focus of the GET FiT Programme for the development of 130 MW of projects of renewable energy generation, i.e., photovoltaic projects with storage and small hydroelectric power plants, although, at a later stage, wind and biomass projects may be considered. Also, the results of this study showed that there is a potential to promote Independent Power Producers ("**IPPs**") in renewable energy in Mozambique.

Proposals for changes in laws or regulations

As mentioned above, the revision of the regulatory framework – more specifically, the Electricity Law – is currently under way. The main goal is to ensure that the applicable framework is consistent and adequate for the promotion of new energy projects, in accordance with the Government's Integrated Plan. For that purpose, the revision of the regulatory framework aims to simplify the regulatory regime and licensing procedure and clarify the attributions of several government and administrative entities in the sector.

In an effort to promote renewable projects, the new regulatory framework is also expected to create specific regulation for power projects using renewable energy resources, including a simplified regime for small-scale and off-grid projects, and a grid code for power feed-in from renewable energy sources.

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Philippines

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Overview of the current energy mix, and the place in the market of different energy sources

Currently, the Philippines is heavily dependent on coal as its primary source for power generation, which comprises 49.6% of the total power mix. Natural gas and geothermal energy follow, at 11.8% and 10.9%, respectively. On the other hand, renewable energy (RE) contributes only 24.6%, while oil-based sources account for only 3.8%. The country's energy mix is likewise heavily imported from other countries, with imported sources constituting 49% of the energy mix.

The country's energy consumption has experienced growth over the years, with an increase of 5.1% in 2017 from its 32.2 million tons of oil equivalent (MTOE) in 2016, reaching 33.9 MTOE as its total energy consumption.

The most energy-intensive sector is transportation, which accounts for 34.9% of total energy consumption, while the residential sector accounts for 27.1%; the industry sector for 23.55%; the commercial sector for 13%; and the agricultural, fishery and forestry sectors for 1.5%.

From the country's total final energy consumption (TFEC) of 33.9 MTOE, petroleum products were the most consumed form of energy, accounting for 48.3%. Biomass trailed with 21.4%, while electricity accounted for 19.8%. Coal made up 8.9%, while biofuels and natural gas comprised 15% and 0.2%, respectively.

In order to establish and secure a more stable and sustainable power supply, the Philippines aims to decrease its dependence and use of coal by diversifying its energy sources. The government has made efforts to develop and promote the use of RE by means of fiscal and non-fiscal incentives. The government's thrust similarly favours the development of liquified natural gas (LNG).

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In 2018, the Philippine Department of Energy (DOE) issued the implementing rules for the green energy option program (GEOP), which allows consumers of more than 100 kilowatts of electricity per month to choose their own power supply source. The GEOP grants consumers an option to source their supply from RE producers. The Department Circular providing the guidelines for the facilitation of GEOP has undergone its third leg of public consultations and is expected to be released this year.

It is expected that the implementation of GEOP will give rise to a reliable market for RE generation, and enhance competition among RE and other power suppliers.

In the first half of 2019, the *Energy Virtual One-Stop Shop* (EVOSS) *Act* was passed into law and DOE Department Circular No. DC2019-05-0007, together with its Implementing Rules and Regulations (IRR). The EVOSS Act aims to streamline the permitting process of power generation, transmission and distribution projects.

Under the EVOSS Act, prospective power generation, transmission or distribution companies can apply, monitor and receive all the necessary permits, as well as make payments for charges and fees, through an online platform called EVOSS.

The system will be managed and maintained by the DOE, while its operations will be monitored by the EVOSS Steering Committee, which is an *ad hoc* committee in existence for only two years since the rules became effective.

The EVOSS Act may result in reduced power generation charges. The introduction of the EVOSS will reduce the steps required to seek a permit, which is a lengthy and costly process that has deterred potential investors. It would also reduce the cost of doing business in the country and encourage more investors.

In this regard, the enactment of the EVOSS Act may propel the objectives of the Electric Power Industry Reform Act (EPIRA), which is a law that sought to reduce the cost of electricity in the country by promoting competition in the energy generation sector. Further, the EVOSS Act may help the Philippines significantly in addressing its energy requirements in the future by stimulating the power generation investment.

Developments in government policy/strategy/approach

In 2011, the DOE launched its Energy Reform Agenda, which was aimed at attaining energy self-sufficiency, energy security, and environmental sustainability. This government policy promoted the development of the RE sector and addressed the looming depletion of the Malampaya gas field, which is the only source of natural gas in the country. Malampaya's supply is expected to drop by 2020 and will only be sufficient until 2027.

This reform in energy agenda is currently embodied in the DOE's Philippine Energy Plan (PEP) 2017–2040, which outlines anticipated changes and sets goals for the energy sector by 2040. It is considered the DOE's blueprint to secure the country's energy future. Among the key items on the government's agenda are: (1) increase RE installed capacity to at least 20,000 megawatts (MW); (2) increase reserves and production of local oil, gas and coal; (3) deliver quality, reliable, affordable, and secure power supply; and (4) provide nationwide electricity access.

Developments in legislation or regulation

In line with the government's policy in developing energy sources that are environmentally and economically sustainable, as well as ensuring nationwide electrification, several laws and regulations have been enacted towards these goals.

In 2017, the President issued Executive Order No. 30 creating the Energy Investment Coordinating Council (EICC), which is tasked to "establish a simplified approval process and harmonise the relevant rules and regulations of all government agencies involved in obtaining permits and regulatory approvals" when it comes to implementing Energy Projects of National Significance (EPNS). The EICC will issue certificates of EPNS when the interested applicants or proponents justify "in a clear and unequivocal manner" how their projects are in consonance with the goals and objects of DOE's PEP 2017–2040.

The most recent enactment by Congress is Republic Act No. 11285, the *Energy Efficiency and Conservation Act*, which was signed into law on 12 April 2019, seeking to standardise energy efficiency and conservation measures in the country by regulating the use of energy-efficient technologies in buildings. It similarly provides for both fiscal and non-fiscal incentives for engaging in energy efficiency and conversation best practices and projects. This Act also created a new government body, the Inter-Agency Energy Efficiency and Conservation Committee, which will oversee implementation of the Government Energy Management Program (GEMP), aimed at reducing electricity and fuel consumption by the government.

Other recent laws/regulations include the EVOSS Act and its IRR. The purpose of the EVOSS Act is to streamline the permitting process of power generation, transmission and distribution projects, which would both reduce the cost of doing business and encourage investors. Under the EVOSS Act, prospective power generation, transmission and distribution companies can apply, monitor and receive all necessary permits, including make payments therefor, through an online platform called EVOSS.

The DOE, through its Renewable Energy Management Bureau, is likewise exploring means to reignite the renewable energy sector. Forthcoming issuances include:

1. *The Omnibus Guidelines Governing the Award and Administration of Renewable Energy Service Contracts (RESCs) and the Registration of Renewable Energy Developers.*
2. *Promulgating the Renewable Energy Market (REM) Rules.*
3. *Guidelines Governing the Issuance of Operating Permits for Renewable Energy Suppliers Under the Green Energy Option Program (GEOP), which is expected to be issued before the close of 2019.*
4. *Enhancement to Net Metering for RE Policies.*
5. *Renewable Energy Safety, health and Environment Rules and Regulations (RESHERR) Code of Practice (COP).*
6. *Guidelines on the Duty-Free Importation and Monitoring of Utilization of RE Machineries, Equipment, Materials and Spare Parts.*
7. *Operationalisation Guidelines for the Collection, Remittance and Utilisation of RE Trust Fund.*
8. *A National RE Program for 2020–2040.*

Judicial decisions, court judgments, results of public enquiries

On 3 May 2019, the Supreme Court of the Philippines promulgated its decision in the case of ***Alyansa para Sa Bagong Pilipinas, Inc. (ABP) vs. Energy Regulatory Commission (ERC)*** (G.R. No. 227670), which nullified the Power Supply Agreements (PSAs) of the Distribution Utilities (DUs) submitted after 7 November 2015 for failure to conduct competitive selection process (CSP) as required under 2015 DOE Circular, entitled Mandating All Distribution Utilities to Undergo Competitive Selection Process in Securing Power Supply Agreements (DOE Circular).

This case stemmed from the issuance by the Energy Regulatory Commission (ERC) of Resolution No. 1, Series of 2016 (ERC Clarificatory Resolution), which postponed the effectivity date of DOE Circular by 130 days. However, the Supreme Court ruled that the ERC does not have the statutory authority to postpone the date of effectivity of CSP, and thereby cannot amend DOE Circular. As a result, the 90 PSAs submitted to the ERC within the 130-day extension period were nullified. Hence, the ERC was ordered to require CSP on all PSA applications submitted within the 130-day extension period.

Major events or developments

Since the shift towards using cleaner energy, coupled with the looming depletion of the Malampaya gas field, efforts have been made to develop and streamline the use of LNG. In March 2019, DOE Secretary Alfonso Cusi signed the notice to proceed for the proposal of First Gen Corporation to build a liquefied natural gas (LNG) import terminal within its power plant complex in Batangas province, which has been granted EPNS status by the DOE.

On 31 July 2019, Solar Para Sa Bayan was the first solar energy company that was granted a 25-year franchise to use RE to provide electricity to unserved/underserved areas in selected provinces.

Proposals for changes in laws or regulations

Consistent with the government policy of shifting away from the use of traditional sources of energy, various bills relating to strengthening and promoting the use of RE are currently pending with the Congress, including:

1. House Bill No. 01481, *An Act Creating the Solar Energy Development Authority and Appropriating Funds Therefor*, which has been pending with the Congressional Committee on Government Reorganization since 24 July 2019;
2. House Bills Nos. 02099 and 02427, *An Act Strengthening the Energy Regulatory Commission by Expanding and Streamlining its Bureaucracy, Upgrading Employee Skills, Augmenting Benefits, and Appropriating Funds Therefor and An Act to Enhance the Governance Structure of the Energy Regulatory Commission*, respectively, both pending with the Congressional Committee on Energy since 29 July 2019; and
3. Senate Bill No. 990, *An Act to Strengthen the Jurisdiction and Power of the Department of Energy Over Petroleum Pipeline Operations and For This Purpose Provide a Petroleum Pipeline Code to Prescribe Standards for the Design, Construction, Operation and Maintenance and Abandonment of Liquid Petroleum Pipelines and Appropriating Funds Therefor, and for Other Purposes*, which has been pending with the Senate's Energy Committee since 02 September 2019.

Moreover, consultations and further drafting of rules are being undertaken for the full implementation of the Renewable Energy Act, as well as the PEP 2017–2040.

Notwithstanding the reforms, the government permitting process for the RE industry remains tedious. The effect of the EVOSS Act and its IRR remain to be seen.

Furthermore, the Philippines' current energy mix highly favours coal – which is primarily imported – as the most heavily used energy source, leading to the high cost of electricity in the Philippines. A more cost-effective energy mix must be established to bring down the Philippines' stifling cost of electricity.

The DOE has expressed willingness to explore other options including nuclear energy, with DOE Secretary Alfonso Cusi stating that: "With all the new findings, technological advancement and successful experiences of countries around the world, nuclear energy holds much promise for our national interest, especially in light of our collective quest to implement our long-term energy plans."

However, to date, the Philippine government has not issued an official position on nuclear energy, perhaps due to the continued strong resistance to it within the country, considering past accidents in other countries involving nuclear facilities. Challenges to the local development of nuclear energy include public acceptance, lack of political will, high infrastructure cost, and disposal of nuclear waste.

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Portugal

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Portugal has become widely known for its leading role in the promotion of renewable energy. After decades when the country remained historically dependent on hydro resources and thermal assets, Portugal has witnessed significant investments in the renewable energy sector, in particular wind energy projects, which already account for almost one quarter of all electricity generated in the country. The past few years have been foreshadowing a boom in solar projects which are expected to become a driving force behind the country's renewable energy goals for the next decade.

Overview of the current energy mix, and the place in the market of different energy sources

In 2018, the energy generation mix in Portugal showed a substantial diversification of energy sources: hydro (13.4 TWh), wind (12.5 TWh), coal (11.1 TWh), natural gas (10.1 TWh), biomass (2.8 TWh), solar (0.8 TWh) and geothermal (0.2 TWh), with cogeneration contributing 5.7 TWh.

According to the Portuguese Renewable Energy Association (APREN), in 2018, electricity from renewable sources accounted for 52.6% of all electricity generated in Portugal, with wind and hydroelectric alone totalling 22% and 23.7% each, notwithstanding average producibility indexes of 1.05 for hydroelectric energy and 1.00 for wind energy. This means that wind energy and hydroelectric power reached nearly 50% of all electricity generated in Portugal in 2018. Other significant sources were natural gas, which reached 18.1% in 2018, and coal at 19.6% of all electricity produced in this year.

A remarkable feat in 2018 was the historical performance of renewable powerplants during the month of March, where the whole of mainland Portugal's energy needs were met exclusively by recourse to renewable energy sources.

Also, according to the reports published by APREN, the share of energy generated from renewable sources in 2018 allowed for a reduction in CO_2 emissions of approximately 12 megatonnes, up from 8.9 megatonnes in 2017, with savings of around €189 million in CO_2 allowances, up from €51 million in 2017.

The energy dependency indexes for the year 2018 also show a reduction from previous years, with the current estimate set at 76% – down from 78% between the years 2007 and 2017, and 85% between 1996 and 2006.

Provisional data included in the APREN reports for the period between January and August 2019 already show that renewable energy sources represent 51.8% of all electricity generated in mainland Portugal, evidence that renewable sources are steadfast in establishing their role in the current energy mix, with wind energy alone accounting for

26.1%, and hydro power in second place with 17.4%.

While wind and hydroelectric energy should continue playing a significant role as drivers in the renewable energy generation in Portugal, it is expected that solar photovoltaic will represent the biggest increase in generation by 2030, when both the Sines and Pego coal plants are expected to have been retired from operation.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Solar auctions

The past 12 months have witnessed significant developments in the Portuguese energy sector, notably in respect of solar energy projects, with the first major solar auction for injection capacity having taken place in June and July 2019, for a total installed capacity of 1,400MW, and with a second auction for 700MW expected to be launched for January 2020.

The boom in solar photovoltaic projects being submitted to the Portuguese General Directorate of Energy and Geology (DGEG), the licensing entity, shows that one of the most abundant potential sources of energy in the country is finally taking centre stage in the renewable energy sector.

The experience gathered from the first auction, as well as the record-low tariffs offered and the shift in investor profile, will likely impact future policies and drive new changes.

Storage options

There have also been recent amendments to the Portuguese legislation which aim at enabling the storage of electricity, whether on its own or jointly with a generation facility. While this is subject to a specific licence and continues to require further regulation to be implemented, it nonetheless shows a step towards the opening of the market to energy storage options which have up until now been scarce.

Together with the entry into operation and the experience gathered from the Graciólica project, located on the island of Graciosa in the Azorean archipelago – which uses a combination of wind and solar power, and has a storage facility meant to generate electricity output covering more than 50% of the island's energy needs – this may bring a renewed focus and investment in energy storage options, allowing for more efficient generation facilities in the future.

Offshore wind energy

Another significant event is the implementation of the Windfloat project – the first offshore wind energy project in Portugal, being developed with innovative floating technology. Despite having an extensive coastline giving access to a vast maritime area, Portugal has not witnessed a boom in offshore wind as countries such as the United Kingdom have. This is mostly due to the subsea conditions and very deep waters near the coast, which do not allow for the installation of wind turbines similar in style to those which have been used all around the world. The Windfloat project has successfully tested a 2 MW prototype and is now expected to have 25 MW of installed capacity entering into operation by late 2019 or 2020. This technology will pave the way to similar projects being implemented, not just in Portugal but elsewhere, overcoming the technical difficulties faced in the past years which had left the country behind in the offshore wind race.

Guaranteed remuneration schemes approaching the end of their term

A growing number of powerplants are approaching the end of their guaranteed remuneration term, following which they shall be placed under market conditions. This entails various levels of changes:

On the one hand, there is a resurgent focus on other forms of revenue which, up until now, had remained relatively dormant, with promoters starting to look at sources such as guarantees of origin (which framework is still to be further developed), as well as corporate power purchase agreements which, as of 2019, have not yet a significant presence in the market.

On the other hand, there is growing interest in the market in undertaking supply activities and energy trading as a means to guarantee the flow of production to the market – particularly so, given that the market aggregator envisaged to undertake the purchase and sale of electricity from these newly merchant plants is not yet effectively in place. This will likely accelerate changes in the sector, both in terms of organisation and legislation.

Developments in government policy/strategy/approach

National Plan for Energy and Climate

A preliminary National Plan for Energy and Climate (PNEC 2030) was presented by the Portuguese Government in January 2019, in which it sets the proposed targets for 2030. The PNEC remained under public consultation until June 2019 and it is expected to be finalised by the end of the year, defining an action plan for carbon neutrality and the strategic investments to be made in respect of energy and climate.

The targets proposed by the Portuguese Government in the PNEC 2030 include a reduction of between 45% and 55% in GEE emissions, and a 35% energy efficiency rate for primary energy consumption. It is estimated that the electricity generation sector will have an installed capacity of approximately 30 GW in 2030, representing an increase of 10 GW by reference to 2015, with renewable energy projects accounting for over 80% of the total installed capacity in Portugal.

The PNEC 2030 also sets goals for energy use and efficiency in the transportation sector, identified as one of the cornerstones of the aim for a decarbonised society, and the promotion and implementation of smart networks and storage so as to ensure service quality and supply safety, as well as flexibility in the demand-supply system.

The Roadmap to Carbon Neutrality (RCN 2050) was also approved in July 2019, establishing the action lines for a carbon-neutral society by 2050, and determining targets of 80% of all electricity generated in Portugal from renewable sources by 2030, to increase to 100% by 2050.

The ambitious targets being set by the government are expected to translate into the enactment of several measures to ensure the energy transition and efficiency and safety of the sector, while promoting a significant increase in the generation and consumption of energy from renewable sources.

Energy taxation

The State Budget for 2018 introduced some relevant changes to the taxation of coal used in the generation of energy, imposing a tax on oil products and CO_2 added tax at a rate of 10% to powerplants using coal in the production of electricity, which were previously exempt from this payment. This rate has increased to 25% for 2019, and it is set to continue increasing progressively until 2022, when such products will be taxed at 100%. This mechanism directly translates the efforts of the Portuguese government in reducing coal production into a phasing-out of fossil fuels in the generation of energy in Portugal.

Through the State Budget for 2019, it has also been determined that the Extraordinary Contribution of the Energy Sector (*Contribuição Extraordinária do Setor Energético* or CESE) shall be extended to renewable energy projects benefiting from a guaranteed remuneration, which up until then and since the enactment of the CESE in 2014, had been exempt from this payment.

The CESE is levied on electricity generators, on the one hand, and on the TSO of the natural gas sector, on the other. The increasing taxation of the energy sector is likely to create a strain on certain sector entities, and this is a far from amicable situation – as evidenced by news reports, according to which several entities in the electricity and natural gas sector are already reportedly challenging the payment of CESE in judicial courts.

Developments in legislation or regulation

Licensing scheme for new projects

Decree-Law no. 76/2019, of 3 June, brought about a sweep of amendments to some of the core legislation of the electricity sector – the first major systematic revision since 2012. It has notably introduced important changes in relation to the attribution of grid reserve capacity and subsequent licensing procedures, as well as a simplified procedure for single-source projects under 1 MW, the entire output of which is meant to be injected into the public grid.

Prior to the enactment of this Decree-Law no. 76/2019, requests made for injection points where grid capacity was unavailable or insufficient (in light of requests placed) would be made by draw. The procedure for the attribution of connection points and licensing of new electricity generation projects now includes a competitive electronic auction process, through which interested parties may bid on lots for the granting of grid capacity.

Interested parties may opt between two remuneration models: one where the powerplant operates under market conditions, with the generator offering a fixed contribution (in EUR/MW) payable to the Portuguese National Electricity System for a period of 15 years; or one where the powerplant benefits from a guaranteed remuneration calculated by applying a bidding discount offered by the sponsor in relation to the reference tariff presented in the auction.

Another option introduced by Decree-Law no. 76/2019, for situations where grid capacity is not available, is to enter into an agreement with the network operator and to provide the necessary investment and funds for the reinforcement of the network so as to connect the envisaged project. In this scenario, the funding burden is put on the promoter, thus ensuring that grid investments do not have an impact on the electricity tariffs and therefore on the consumers.

Limitation to the transfer of licences

In an attempt to overcome the grid capacity scarcity witnessed in the past years and put a halt to licence trading, recent amendments to the sector legislation have included a prohibition on transferring the grid capacity reserve and the corresponding production licence (whether directly or through the share or asset sale of the promoter) until the project is deemed able to enter into commercial operation.

Hybrid electricity generation

Powerplants may now generate electricity from different primary sources (up to two) in the same infrastructure and through the same connection point, allowing for an increase in generation and contributing to a greater energy mix, without requiring additional investments for reinforcement of the grid, due to the injection capacity remaining the same, notwithstanding the different technologies remain subject to independent licensing.

A growing interest in combining wind and solar has already been reported from major players in the sectors, as it would allow powerplants to maximise output and efficiency given the different sources' availability and feasibility, without requiring further infrastructure investments from the network operator, as the injection capacity remains the same.

Feed-in tariffs

As a result of both the financial constraints which the country has faced in recent years and the subsequent change of policy direction as regards incentives to the energy sector – and in particular, for renewable energy projects – Portugal has witnessed a halt to the guaranteed remuneration schemes previously applicable to renewable energy projects.

Recent amendments have now partially reintroduced the feed-in tariff regime under special conditions, albeit at significantly lower prices, and provided that such remuneration is either secured through a public tender or auction, or in the context of overpowering, or for projects using hybrid generation to combine a different primary energy source to an existing powerplant.

Biomass projects

The biomass generation regime allows for the implementation of biomass powerplants not only by private investors and players (who remain under a specific regime), but also by the municipalities or, alternatively, by private entities subject to a public contract being executed with the relevant municipality.

However, such projects have not yet been launched by the municipalities. Decree-Law no. 120/2019, of 22 August, introduced certain amendments to the regime applicable to the installation of forest biomass powerplants, in an attempt to boost the implementation of projects using forest biomass, and simultaneously working towards better land management and planning to fight against forest fires which have ravaged significant parts of the country in recent years.

Overpowering

As had already been announced by the Portuguese government, changes have been introduced to the overpowering regime in that the Portuguese regulator (ERSE) must evaluate each request in order to determine whether the envisaged overpowering may carry an adverse effect for the National Electricity System.

As a large number of powerplants under the guaranteed remuneration schemes have opted in to the extension regime enacted in 2013 – which allowed plants to apply a floor and cap to their market remuneration for either the first five or the first seven years (depending on the conditions) after the end of their respective feed-in tariff periods – the amendments now introduced by this Order no. 43/2019, of 31 January, determine that the prior consultation of ERSE is only waived if the generators accept a non-revisable tariff of €45/MWh for a single period of 15 years, thus barring the energy output from such overpowering being considered for the abovementioned extension period (if applicable).

Clawback mechanism

The legal framework created in 2013 for the prevention of market distortions between Portugal and Spain (Iberian Market) was designed to restore competition equilibrium in the wholesale electricity market between the two countries by eliminating windfall profits received by Portuguese generators as a result of taxes introduced in Spain and therefore higher pool prices, a situation which was viewed as affecting Iberian electricity prices.

This mechanism was halted in 2018 for a six-month period, in acknowledgment of the suspension for the same duration of the tax measures imposed in Spain. Decree-Law no. 104/2019 was recently published on 9 August 2019, harmonising the clawback mechanism to MIBEL rules, and foreseeing the possibility of a payment on account – which value is to be defined every year by governmental order.

Judicial decisions, court judgments, results of public enquiries

2018 saw the creation of a parliamentary inquiry committee with the goal of assessing whether there were "excessive rents" being paid to generators in the electricity sector as a result of energy policies over the years. The main focus of this committee (comprising representatives of all political parties with parliamentary seat) was the remuneration being paid to electricity generators, both renewable and non-renewable, and the potential accountability of political actors with influence over such energy "rents" being paid.

The final report was approved in May 2019 and brought to the Portuguese Parliament in July 2019. Although the recommendations and proposals made in the final report are not binding, the Parliament and the Government are likely to take the findings of the inquiry committee into account in the making of future policies and measures applying to the energy sector.

Major events or developments

Over the years, promoters which had obtained licences for the installation and development of renewable energy projects were met with difficulties in securing the necessary financing for the works required. As the projects stalled, the country was faced with a problem of lack of grid availability for new projects, and obstacles in attracting new investment.

Indeed, while there was evidence of a growing interest in developing new solar photovoltaic projects, the government needed a solution to free up the grid and attract investment. This led to a solar auction taking place between June and July 2019 – the biggest since 2007 – with bids for 1,400 MW of installed capacity. A second auction is expected to take place in January 2020, for another 700 MW of solar power.

The auction attracted the attention of foreign investors, with a large number of bidders coming from the UK, Germany, France and Spain, and broke records for the lowest bids, second only to India, according to news outlets and sector entities. The low tariffs attributed in the auction have also set a precedent for future projects, marking a shift in paradigm for investors, who will have to readjust business models to secure revenues. It is also worth mentioning that a significant proportion of the winners in this first auction were newcomers to the Portuguese market, at the expense of the major players which have dominated the Portuguese market in the past decades.

Proposals for changes in laws or regulations

Market aggregators

With several renewable energy projects benefiting from the guaranteed remuneration scheme reaching the end of their feed-in tariffs, it is expected that market aggregators will undertake the purchase and sale of power generated by such plants. While the figure of the market aggregator was first foreseen in the sector regulations in 2012, no entity has yet undertaken this activity.

Recent amendments enacted in 2019 have determined that this function shall remain subject to a specific licence to be attributed in the context of a public tender. A licensed market aggregator will have the role of acquiring the electricity generated under the special regime under market conditions, at a national or at a local level. Up until then and for smaller projects, the last resort supplier will temporarily undertake this activity.

This is expected to change once the tender is launched and new entities take on this role.

Low-voltage electricity distribution concessions

2019 was set to be the year for low-voltage electricity distribution tenders, with plans having been announced for a major nationwide public tender for the low-voltage distribution concessions. The Portuguese Regulator had proposed that mainland Portugal be divided into three areas – north, centre and south – and that the tenders would be launched jointly by all municipalities in such areas, other than those which would undertake low-voltage electricity distribution on their own.

Despite several concession agreements having reached or reaching their term in 2019, the public tender has not yet been announced and is likely to be postponed to 2020, with the municipalities either undertaking the activity after the term of the concession agreements, or allowing the current concessionaires to continue as such until then. The launching of the public nationwide (mainland Portugal) tender in 2020 is expected to introduce competitiveness and other changes to the low-voltage electricity distribution system.

Self-consumption and energy communities

The government has announced the approval of the final version (pending publication in the Portuguese official gazette) of legislation introducing significant changes to the framework for self-consumption and creating the possibility of energy communities, in an effort to align the Portuguese electricity sector with European Directives and to comply with the PNEC 2030 targets of 47% of renewable energy consumption by 2030, which require that renewable energy account for at least 80% of all electricity generated in Portugal.

Guarantees of origin

Despite being foreseen in the Portuguese legislation since 2010, the framework for guarantees of origin has been subject to several amendments which have continuously shifted powers granted for the issuance of such guarantees of origin among different entities. As a result, there are currently no guarantees of origin being issued in Portugal.

Notwithstanding, the Portuguese Government has publicly stated that it is its intention to promote the issuance of guarantees of origin. And the procedural manual for the issuing entity was under public consultation during the month of August 2019, foreshadowing significant developments in this respect. This may become an important source of revenue for projects, in particular, given the fact that few projects have been attributed with any form of guaranteed remuneration, and those which have – as mentioned above, in relation to the solar auctions – have secured record-low remunerations.

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Russia

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Overview of the current energy mix, and the place in the market of different energy sources

Russia's energy sector is strategic for the country, insofar as energy is the driver of Russian economic growth and the main source for replenishing the state budget.

Russia's energy sector consists of the following key subsectors:

- oil industry;
- gas industry;
- coal industry; and
- electric-power industry (atomic power, hydropower).

As one of the world's dominant suppliers of energy resources, Russia occupies a confident place on the international energy market. BP analysts think that over the next 20 years, Russia will continue to be one of the largest energy-exporters in the world, satisfying more than 5% of global demand for primary energy resources by 2040. Russia is also predicted to remain one of the world's leading producers of fossil fuels, accounting for 14% of global oil & gas production. For example, by 2040, Russian oil production will grow by 2 million bpd (to 13 million bpd), while Russian gas production will climb by 29% (to 72 billion SCFD) by 2040 against a backdrop of growing demand on the global markets.

Russia's total energy resources can be broken down according to the consumption level of primary energy resources in 2016: oil (22%); gas (52%); coal (8%); atomic power (7%); hydropower (6%); and renewable resources (2%). BP analysts forecast only a slight change in the breakdown in the period through 2040.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

<u>Oil industry</u>

At the end of 2017, the volume of oil production amounted to 546.5 million tons, which is 0.3% less than in 2016. This trend is due to the implementation of agreements between "OPEC+" countries on restrictions on oil production, which also influenced the dynamics of exports. At the end of 2017, the volume of oil exports amounted to 252.6 million tons, decreasing by 0.9% compared to the level of 2016. At the same time, the reduction in export deliveries to non-CIS countries amounted to 0.8% and, to the CIS countries, 2.3%. Investments by the type of activity "production of crude oil and oil (associated) gas" in 2017 amounted to about 1.6 billion rubles, and the index of physical volume of investments in fixed assets grew by 14.6%.

Until 2024, no special changes in the level of oil production are expected. The forecast for the development of the oil industry implies a stable level of oil production until 2024, which will reliably meet the needs of the domestic market and ensure the economically viable export of oil and oil products.

The main regions of oil production remain Western Siberia and the Ural-Volga region, where production is stabilised through new drilling and geological and technical measures at existing fields. In Eastern Siberia, the Verkhnechonskoye (PJSC Rosneft Oil Company) and Talakanskoye (OJSC Surgutneftegas) fields are already under development. In addition, industrial oil production has begun at the Suzunskoye and Tagulskoye fields (PJSC Rosneft Oil Company).

PJSC LUKOIL has increased oil production at its fields V. Filanovsky, PJSC Gazprom Neft – and at the Prirazlomnoye and Novoportovskoye fields.

The main emphasis is on the development of new oil fields. However, the main increase is expected due to the commissioning of new deposits. Under the draft production-sharing agreement (PSA), the actual production of liquid hydrocarbons complies with the parameters established by the current design technological documentation. Work on the implementation of the Sakhalin-1, Sakhalin-2, and Kharyaginskoye deposits projects is carried out in accordance with the annual work programmes and cost estimates. According to the current technological schemes in the planning period, it is planned to drill and put into operation a number of producing wells, which is also reflected in the work programmes and cost estimates.

It should be noted that the achievement of these levels of oil production will depend on macroeconomic conditions, the lifting of external technological and financial sanctions from Russian vertically integrated oil companies, the effectiveness of the import substitution process, and the development of domestic production in related industries.

For the time period under consideration, it is not intended to commission new fields on the continental shelf of the Russian Federation. Changes in offshore production will occur within the framework of increasing production and reaching the design level of production at existing fields.

The growth of oil and oil products in 2018

The volume of oil production in 2018 is estimated at 549.0 million tons (0.5%). Production will be affected by the agreements on proposed increases reached at the meeting in Vienna in June 2018 by the OPEC+ member countries.

Oil exports will amount to 255.7 million tons (+1.2% compared to 2017). At the same time, deliveries to non-CIS countries are expected to grow by 1.2%, and to neighbouring countries – at the level of 2017 (+1.9%). Taking into account trends in the external economic situation, credit risks and restrictions, including an agreement with OPEC and countries outside its quota for oil production quotas, further opportunities to maintain oil production will depend on the ability of companies to implement modern techniques for improving oil recovery and software for drilling and production processes, from the implementation of import substitution projects in related industries, as well as the timely commissioning of new fields located in remote regions with difficult development conditions.

Due to new fields introduced and planned for commissioning, and stabilisation of production at "mature fields" (as a result of expansion of the production drilling zone and maintaining its profitability), oil production is expected to increase in the forecast period.

At the same time, risks remain that insufficient competence for the implementation of offshore and other complex projects, with restrictions on the import of equipment and technologies for their implementation, may have a negative impact on the dynamics of oil production.

Peak growth in oil production and refining is expected in 2021

In the current economic situation, in general terms, oil production is projected to increase to 557 million tons by 2024 (562 million tons by 2021). In the context of the development of primary oil refining, with the gradual modernisation of oil refineries and an increase in the depth of refining, oil exports will amount to 253.9 million tons by 2024 (257.3 million tons by 2021). Oil exports to non-CIS countries are projected to increase to 235.45 million tons by 2024 (238.85 million tons by 2021), mainly due to an increase in supplies to the countries of the Asia-Pacific Region (APR). Export to the CIS countries will remain at the current level throughout the forecast period. The share of imports in oil production is not significant.

Construction and reconstruction of pipelines until 2024

In accordance with the Transneft PJSC long-term development programme, the following major projects are under way for the construction and reconstruction of pipelines for the transportation of oil and oil products.

Phased expansion of transmission system operator (TSO) ESPO, including:

- Up to 80 million tons per year on the Taishet-PSP Skovorodino GNPS section to ensure oil transportation for export to the PRC and towards the Kozmino SMNP, as well as to oil refineries in the Russian Federation. The completion of the project is scheduled for 2019.
- Up to 50 million tons of oil per year at the Skovorodino-Kozmino oil and gas production site to ensure oil transportation for export through the Kozmino oil and gas production complex, as well as to oil refineries in the Russian Federation (RN-Komsomolsky Oil Refinery LLC, Khabarovsk Oil Refinery OJSC, CJSC, VNKhK). The completion of the project is scheduled for 2019.
- Construction of the branch pipeline "TSO VSTO-Komsomolsky Oil Refinery" with the subsequent connection of the refinery to the main oil pipeline system (hereinafter – MN).

In addition, until 2024, work will be carried out on:

- reconstructing the existing oil pipelines of Western Siberia to ensure the loading of the Eastern Siberia–Pacific Ocean pipeline system to 80 million tons of oil per year and to ensure its safe operation with an increase in oil pumping volumes;
- increasing the throughput capacity of the Usa–Ukhta and Ukhta–Yaroslavl oil pipelines to ensure that additional oil volumes of the Timan–Pechora region are admitted to the Transneft oil pipeline system;
- ensuring an increase in oil supplies to oil refineries in the Krasnodar Territory; and
- increasing the throughput capacity of oil pipelines to ensure the supply of oil to the refineries of PJSC TANECO.

The most significant and major projects for the development of oil trunk pipelines in this period in the framework of the South project:

- construction of MNPP "Volgograd–Tikhoretsk" (South project, 2 stage);

- construction of the MNPP Volgograd Oil Refinery–GPS Tinguta;
- expansion of the Sever project – the development of a system of trunk pipelines to increase the supply of petroleum products to the port of Primorsk to 25 million tons per year; and
- reconstruction of the trunk pipeline system to increase the volume of transportation of petroleum products to the Moscow region.

Thus by 2023, it is forecast there will be: a decrease in the volume of oil transportation to 476.3 million tons (-0.3% compared to 2017); an increase in oil turnover to 1,238.9 million tons (+2.3% compared to 2017); an increase in the volume of transportation of oil products to 50.0 million tons (+51.1% of the level of 2017); and an increase in the turnover of oil products to 68.6 million tons (+46.6% of the level of 2017).

Gas industry

Increasing gas production by 2021

The predicted growth in gas production (up to 730.1 billion cubic metres in 2021 and up to 756.5 billion cubic metres in 2024) will be provided by more active development of the fields of PJSC Gazprom, as well as an increase in production by independent gas producers in the context of their non-discriminatory access to the Unified Gas Transportation System.

At the same time, demand in the domestic gas market will stabilise and will reach 491.1 billion cubic metres by 2024 (484.8 billion cubic metres in 2021), while maintaining demand on the foreign market will ensure gas exports at the level of 235.3 billion cubic metres (220 billion cubic metres in 2021). By 2024, LNG exports will increase to 37.5 billion cubic metres (35.5 billion cubic metres in 2021).

The main volumes of gas will be supplied to the domestic market, which in the medium term will be characterised by the stabilisation of growth rates and a decrease in the gas-intensity of industry. Prospects for increasing domestic supplies relate to the development of gas chemistry, an increase in the use of gas as a motor fuel, as well as the ongoing implementation of regional gasification programmes.

What will ensure the increase in gas production?

The projected increase in gas production is planned by dint of:

- South Tambey gas condensate field (Yamal Peninsula), which is the resource base of the Yamal–LNG project, commissioned in December 2017; and
- Chayandinskoye oil and gas condensate field (planned to be commissioned in 2019), located in the Republic of Sakha (Yakutia), and Kovykta gas and condensate field (planned to be commissioned in 2022), located in the Irkutsk Region.

These fields are the resource base of the Power of Siberia gas trunk line.

The predicted dynamics of growth in gas production by 2024 are attributable to an increase in export by pipeline and liquefied natural gas. An increase in pipeline gas exports is projected due to gas supplies to China through the Power of Siberia gas pipeline.

The growth in exports of liquefied natural gas has been due to the commissioning of a liquefied natural gas plant on the Yamal Peninsula. The forecast for natural gas consumption is based on plans for the development of the economy of the constituent entities of the Russian Federation, taking into account the implementation of high-priority investment projects, the main strategic documents of the federal and regional levels, and the plans of the constituent entities of the Russian Federation for the development of the fuel and energy complex.

The forecasts are based on: regional gasification programmes for housing and communal services, industrial and other organisations; reports on the realisation of these programmes for 2017; and the gas consumption forecast laid down by the general gas supply and gasification schemes of PJSC Gazprom. When generating the forecast, all energy facilities, as well as the main largest industrial consumers, were taken into account, while specific gas producers and consumers were considered.

In the field of the construction of gas mains, PJSC Gazprom is implementing the following main projects:

As part of the Eastern Gas Program for organising gas supplies from Russia to China, the Power of Siberia gas trunk line is under construction, which will become the general gas transmission system for the Irkutsk and Yakutsk gas production centres. Export productivity will be 38 billion cubic metres per year. The total length of the main gas pipeline from the Chayandinskoye field to the Chinese border in the region of Blagoveshchensk is about 2,158.5 km.

The length of the gas pipeline from the Kovykta to the Chayandinskoye fields is 803.5 km.

In accordance with a complex plan of measures to provide government support for the construction of gas infrastructure facilities, including the Power of Siberia gas trunk line, the Ministry of Energy of Russia, jointly with interested ministries and departments, was instructed to take measures, including enacting appropriate legislation, to optimise the implementation time for the construction of facilities in the project, "Gas Pipeline Power of Siberia".

As part of improving the reliability of gas supplies to Turkey, as well as South and Southeast Europe, a gas pipeline is under construction along the bottom of the Black Sea from Russia to Turkey, and also a land transit line to the Turkish border with contiguous countries. The project provides for the construction of two lines of the Turkish Stream gas pipeline, the capacity of each of which will be 15.75 billion cubic metres.

As part of the expansion of the gas transportation system for exporting gas to Europe and improving the reliability of supplies, the Nord Stream-2 project is being implemented, which provides for the construction of two sections of a sub-sea gas pipeline with a total capacity of 55 billion cubic metres of gas per year from Russia to Germany along the Baltic Sea bed.

Thus, according to PJSC Gazprom data, the volume of commercial transportation through the main gas pipeline transport in 2021 will increase by 6.3% compared to 2017, amounting to 710.6 billion cubic metres, while the volume of freight traffic through the main gas pipeline transport will increase by 0.7% compared to 2017, amounting to 1,632.6 trillion cubic metres.

The supply of pipeline gas to non-CIS (Commonwealth of Independent States) countries through the Blue Stream gas pipeline in 2019–2024 is projected at 14.65 billion cubic metres, which will be 92.4% of the level of 2017.

Coal industry

External demand for coal

According to analysts at PwC and McKinsey & Company, global energy demand will plummet in the coming decades. Thus, according to PVS reports, the demand for coal energy is currently 27% of the entire energy market. By 2040, global coal demand will only be 22%. This is largely determined by two factors: (1) China is the largest global producer and consumer; and (2) gas and renewable energy sources are projected to almost double their growth in the energy demand market.

Domestic demand for coal

An energy transfer will occur, with the reduction in domestic demand for coal accelerating to 22%, mainly in power plants, rising gas prices and intensified energy conservation. At the same time, the absolute consumption of coal in all scenarios for municipal needs will radically decrease (one quarter the level of 2018).

Together with devaluation and maintaining a low ruble exchange rate, this makes exports the main driver for the development of the coal industry. The processes taking place on the global coal market, in particular, the climate policy of many countries (especially the EU and China), create high uncertainty for this industry in Russia. In a conservative scenario, coal demand growth is still expected from Asia-Pacific countries (primarily India and Southeast Asia, where the demand for high-quality coal will increase), as well as the Middle East and Africa; while in China and the developed countries of Asia (Japan, South Korea), demand is likely to stagnate, and the European direction will gradually decrease as a result of a decrease in both demand and demand for imports. In the scenarios of the Innovation and especially the Energy Transition, a decrease in domestic demand is accompanied by a decrease in coal exports not only in Europe but also in Asia.

Electric-power industry

In Russia, as in the whole world, the leading electrification of the economy will go ahead. The highest growth rates will show renewable energy sources. In the Energy Transfer scenario, the volume of energy consumption will grow by 36% by 2040, with the share of electricity in the volume of energy consumption increasing to 47%.

According to the forecasts of the Moscow School of Management Skolkovo, the foundation of the Russian electric power industry will remain thermal power plants (about 62% of total electricity production in 2040). The highest rate of growth in electricity generation will be shown by renewable energy sources (15% per year until 2040).

The state has created mechanisms to stimulate the use of solar and wind energy in the electricity market, but climatic factors and the geography of renewable energy resources until 2030 make renewable energy sources not competitive in comparison with gas.

So, in Russia, the repair of the boiler unit of the 3rd unit of the Berezovskaya Thermal Power Plant (TPP) was completed in 2019. Full commissioning of the unit is expected by early 2020. Also, at the beginning of 2020, four chimneys will be repaired at Surgutskaya TPP-2, Yayvinskaya TPP, Shaturskaya TPP and Smolenskaya TPP.

Thanks to the capital investments of the Company (PJSC Rosseti) as part of the implementation of the investment programme and repair work, in 2018 the turnover amounted to more than 20.6 billion rubles.

According to PJSC Rosseti's annual report, a 15% decrease in capital expenditure, a 30% decrease in operational expenditure, and a 30% increase in EBITDA make investing in this industry attractive. So, by 2030, experts of PJSC Rosseti forecast: (1) the formation of a source of stable dividend payments; and (2) the opportunity for long-term investment.

On December 21, 2018, the Board of Directors of PJSC Rosseti approved the Concept, "Digital Transformation 2030". This concept will optimise and change the logic of the technological process as a result of the introduction of digital technologies based on the analysis of big data.

In 2019, the draft Development Strategy of PJSC Rosseti for 2019–2024 and the period until 2030 was formulated. In February 2019, the Government of the Russian Federation adopted documents of a strategic nature, which will also be reflected in the Development Strategy of PJSC Rosseti.

Hydropower industry

In January 2019, the Central and Western energy regions of Yakutia were connected to the Unified Energy System of Russia. PJSC Yakutskenergo, a subsidiary of PJSC RusHydro, transferred the functions of the operational dispatch control in this area to the System Operator of the Unified Energy System. This will eliminate the operational costs of managing the hydraulic system of the Russian Federation.

RusHydro Group also commissioned the third hydraulic unit at UstSrednekanskaya HPP in the Magadan Region. As a result, the station's capacity increased by 142.5 to 310.5 MW.

In February 2019, the transaction was completed on the sale of a 40% stake in PJSC RusHydro to the Voith group in the VolgaHydro joint venture for the production of hydroturbine equipment in the Saratov Region. The monetary valuation of the stake of PJSC RusHydro is 450 million rubles – determined by an independent appraiser, this amount fully covers the investments of PJSC RusHydro in the project.

The long-term credit rating of PJSC RusHydro, as well as the debt rating for all issues of Eurobonds, was raised to the investment level of Baa3 (outlook stable).

In March 2019, RusHydro and RUSAL commissioned the first series of the Boguchansky aluminum smelter, which is part of the Boguchansky metallurgical association, as a part of two launch complexes.

Several projects were completed at once within the framework of the RusHydro comprehensive modernisation programme: the penultimate hydraulic turbine was replaced at the Novosibirsk Hydroelectric Power Station; unit No. 9 was commissioned at the Saratovskaya Hydroelectric Station; and unit No. 3 of Volzhskaya Hydroelectric Station was commissioned with a new hydrogenerator, a hydraulic unit from station Number 3.

PJSC RusHydro became one of the leaders in the indices of the Russian Union of Industrialists and Entrepreneurs, "Responsibility and Openness" and "Vector of Sustainable Development".

In April 2019, PJSC RusHydro held a public hearing of the draft consolidated corporate report for 2018 with the participation of representatives of major stakeholder groups.

The Board of Directors approved the new version of the Regulation on the Dividend Policy of PJSC RusHydro. The basic scenario is the payment of 50% of the RusHydro Group's profit, in accordance with international financial reporting standards. The minimum amount of dividends is the average value of the amount of dividends for the previous three years. The period of validity of the Regulation is three years.

The main burden of the increase in generating capacity falls on non-carbon and gas generation. In a conservative scenario, the capacity increase by 2040 is 22% (56 GW, a quarter of which is RES), and in the Energy Transition scenario, taking into account the accelerated electrification of the economy and the active promotion of renewable energy with lower KIUMs, it will be necessary to increase installed capacities by 55% (by 133 GW, of which 43% will be renewable energy). Moreover, among the renewable energy sources, the main potential in Russia comes from solar and wind power plants, as well as biomass and waste thermal power plants. Skolkovo experts also noted that undeservedly forgotten small hydropower plants can make a significant contribution.

Also, according to analysts at McKinsey & Company, one of the main trends relevant for Russia is "Distributed Energy Generation". So, for remote villages in Siberia, it will be most relevant to receive energy from a local source (like a "small hydroelectric power station"), and not from the main grid.

Atomic power industry

In Russia, 35 nuclear reactors provided a historic maximum of 190.2 TWh of electricity in 2017. Nuclear energy contributed 17.8% – up from 17.1% in 2016 – to the country's electricity mix. Rosatom is hoping to further increase production in the coming years, with output in 2019 expected to reach 214 TWh.

The start of 2018 saw Russia make considerable progress in the development of new nuclear reactors, with the connection to the grid of the Rostov-4 reactor in February – 35 years after its construction was first started – and the first unit at the Leningrad-2 power station in March, bringing the fleet to 37 reactors, plus the official launch of a two-reactor floating nuclear power plant. Once these are operational, Russia will only have three reactors under construction: Leningrad 2-2; Novovoronezh 2-2; and Kursk 2-1, whose construction started in April 2018.

During the summer of 2019, the two-reactor floating nuclear power plant is expected to be taken to its final location of Pevek. Critics of the project point out that the risk of accidents on a floating nuclear plant is greatly increased because they are even more susceptible to the elements, subject to threats of piracy, and if deployed widely would increase the risks of nuclear material proliferation.

It was suggested that in 2017, 16.5 billion rubles (US$274 million) was allocated for construction, with completion expected in 2022.

In August 2016, a Government decree called for the construction of an additional 11 reactors by 2030, which includes two new fast-breeder reactors, a VVER-600 at Kola and seven new VVER-TOI units at Kola, Smolensk, Nizhny Novgorod, Kostroma and Tatar.

The budget for construction of new reactors is expected to be in 2018, 2019 and 2020 respectively, a modest 15.7 billion rubles (US$250 million), 16.6 billion rubles (US$260 million) and 17.7 billion rubles (US$280 million).

Following the completion of the 880 MW fast-breeder reactor in the Urals and a VVER-1200 in southern Russia, the wholesale price of electricity increased by 15–20% compared to before the two units were commissioned.

There are mainly three classes of reactors in operation: the RBMK (a graphite-moderated reactor of the Chernobyl type); the VVER-440; and the VVER-1000. Both the RBMKs and VVER-440 have been granted a 15-year life extension to enable them to operate for 45 years, although there are plans to extend this in some cases to 60 years.

Russia is an aggressive exporter of nuclear power, with, according to Rosatom, 33 separate projects, although it only lists the following: Bangladesh (two reactors at Rooppur); Belarus (two reactors at Ostrovets); China (one reactor at Tianwan); Egypt (four reactors at El Dabaa); Finland (one reactor at Hanhikivi); Hungary (two reactors at Paks); India (four reactors at Kudankulam); Iran (one reactor); and Turkey (four reactors).

The past 12 months represent a successful year for Russian exports with the start of construction of the first reactors in Turkey, Kudankulam-3 and -4 in India, and Rooppur-1 in Bangladesh, as well as the signing of a US$30 billion deal to supply four VVER-1200s to Egypt.

In June 2018, Rosatom signed a further agreement with China National Nuclear Corporation. The deal was said to be for the supply of four VVER-1200 reactors – two for Tianwan, and two at Xudapu.

Developments in government policy/strategy/approach

On September 29, 2018, the Main directions of the activities of the Government of the

Russian Federation for the period 2019–2024 were approved (approved by the Chairman of the Government of the Russian Federation, D.A. Medvedev 09/29/2018 No. 8028p-P13) and Order of January 29, 2019 No. 45 "On approval of the activity plan of the Ministry of Energy of the Russian Federation for the period 2019-2024".

In accordance with the Activity Plan, the objectives of the Ministry of Energy for the next five years will be:

- High-quality provision of the needs of the domestic market in energy products, energy and raw materials.
- Improving the energy and environmental efficiency of Russian energy, expanding the scale of innovation activity.
- Changing the approach to the system of relations and pricing models in the field of heat supply, creating economic incentives for the effective functioning and development of centralised heat supply systems.
- The introduction of advanced and digital technologies in the fuel and energy complex, as well as the effective implementation of the powers vested in the Ministry of Energy of Russia.

The Government's Legislative Commission approved a future law prohibiting new regions from leaving the electricity market. We are talking about the draft federal law, "On Amendments to Article 36 of the Federal Law "On the Electric Power Industry", regarding the limitation of the list of individual parts of the price zones of the wholesale market, which establishes the features of the functioning of the wholesale and retail markets", initiated by the Ministry of Energy of Russia.

The bill proposes to establish a restriction on the inclusion of new territories in the list of subjects of the Federation, which the Russian government can assign to separate parts of price zones for which regulated electricity prices are set.

The State Duma adopted in the first reading amendments to the law "On Heat Supply", aimed at reducing the number of heat supply organisations; there are about 66,000 of them. Ineffective companies can leave the market as soon as the government is empowered to establish the necessary performance indicators for such organisations.

A draft law on changing the deadline for obtaining a licence for energy sales activities will be submitted to State Duma deputies for consideration. According to the lower house of parliament, the government proposes to extend these terms by a year and a half.

The government is developing a decree that will optimise the use of existing network infrastructure. This was announced by Deputy Minister of Energy of the Russian Federation, Andrei Cherezov at an expanded meeting of the Committee of the Council of the Federation of the Federal Assembly of the Russian Federation on federal structure, regional policy, local self-government and affairs of the North on the topic, "On the efficient use of network capacity reserves".

The State Duma approved in the first reading the exemption from export duties of fuel, oils, lubricants for drilling rigs, which are used in the exclusive economic zone of the Russian Federation, on the continental shelf and in the Russian sector of the Caspian Sea bottom for the study, exploration and production of hydrocarbons.

Developments in legislation or regulation

Energy legislation in the Russian Federation is represented by the following list of regulatory acts that carry both general-legal and special significance:

- Civil Code of the Russian Federation (Part II), governing relations among subjects of law with respect to power-supply agreements (paragraph 6, Chapter 30).
- RF Federal Law No. 35-FZ dated 26.03.2003 "On the Electric-Power Industry" establishes the legal foundations of economic relations in the sphere of the electric-power industry and defines the authorities of bodies of state power in the regulation of these relationships, as well as the main rights and obligations of electric-power-industry subjects under the performance of activity in the sphere of electric power and engaging with their consumers.
- RF Federal Law No. 69-FZ dated 31.03.1999 "On Gas Supply in the Russian Federation" determines the legal, economic and organisational foundations of relations in the area of gas supply in the Russian Federation and is aimed at ensuring satisfaction of the state's need for strategic energy resources.
- RF Federal Law No. 190-FZ dated 27.07.2010 "On Heating Supply" establishes the legal foundations of economic relations arising in connection with the generation, transmission and consumption of thermal power, thermal capacity, coolant featuring the use of heating-supply systems and the creation, functioning and development of such systems, and also defines the authorities of bodies of state power and local self-government bodies responsible for population centres and urban districts in terms of regulation and control in the sphere of heating supply, and the rights and obligations of heating-supply consumers, heating-supply organisations and heating-grid companies.
- RF Federal Law No. 147-FZ dated 17.08.1995 "On Natural Monopolies" determines the legal foundations of federal policy with respect to natural monopolies in the Russian Federation and is aimed at achieving a balance of interests among consumers and natural-monopoly entities, ensuring the affordability of the goods sold by the latter to consumers as well as the efficient operation of the natural-monopoly entities themselves.
- RF Federal Law No. 135-FZ dated 26.07.2006 "On the Protection of Competition" determines the organisational and legal foundations for the protection of competition for the purposes of ensuring the unity of the economic space, the free movement of goods, the freedom of economic activity in the Russian Federation, the protection of competition and the creation of conditions for the efficient functioning of the commodity markets.
- RF Federal Law No. 261-FZ dated 23.11.2009 "On Conserving Energy, Improving Energy Efficiency and Amending Certain Legislative Acts of the Russian Federation" regulates relations in the area of energy conservation and improving energy efficiency, with the aim of creating the legal, economic and organisational foundations for the stimulation of energy conservation and improvements to energy efficiency.
- RF Law No. 2395-1 dated 21.02.1992 "On Subsoil" governs relations arising in the area of the geological exploration, use and conservation of subsoil resources, the use of the waste generated in the extraction of mineral deposits and related refining operations, specific mineral resources (the brine of estuaries and lakes, peat, sapropel and others), underground waters, including associated waters (waters extracted from the subsoil together with raw hydrocarbon deposits) and waters used by subsoil users for their own production and technological needs.
- RF Federal Law No. 225-FZ dated 30.12.1995 "On Production-Sharing Agreements", adopted in the furtherance of Russian Federation legislation in the area of subsoil use and investment activity, establishes the legal foundations of relations arising in the

process of the making of Russian and foreign investments in the surveying, exploration and extraction of raw minerals in the territory of the Russian Federation, as well as on the continental shelf and/or within the exclusive economic zone of the Russian Federation on production-sharing-agreement (PSA) terms.

- RF Federal Law No. 116-FZ dated 21.07.1997 "On the Industrial Safety of Hazardous Production Facilities" determines the legal, economic and social foundations of ensuring the safe operation of hazardous production facilities and is aimed at preventing accidents at such facilities and ensuring the preparedness of legal entities and individual entrepreneurs operating hazardous production facilities (hereinafter also referred to as "hazardous-production-facility operators") for the localisation and liquidation of the aftermath of such accidents.
- RF Governmental Resolution No. 1178 dated 29.12.2011 "On Pricing in the Area of Regulated Prices (Tariffs) in the Electric-Power Industry" establishes the main principles and methods of price (tariff) regulation in the electric-power industry.
- RF Governmental Resolution No. 1075 dated 22.10.2012 "On Pricing in the Area of Heating Supply" defines: the main principles and methods for determining the tariffs for thermal power (capacity) and coolants; tariffs for the services involved in the transmission of thermal power and coolants; the procedure for establishing regulated prices (tariffs) in the area of heating supply; as well as the terms and procedures for adopting decisions on the deregulation of tariffs and the re-regulation of tariffs following their deregulation.
- RF Governmental Resolution No. 1172 dated 27.12.2010 "On Approval of the Rules for the Wholesale Electric-Power and Capacity Market and the Amendment of Certain Acts of the Government of the Russian Federation Concerning the Functional Organisation of the Wholesale Electric-Power and Capacity Market" establishes the legal foundations for the functioning of the wholesale electric-power and capacity market, including the regulation of relations associated with the turnover of electric power and capacity on the wholesale market, as of January 1, 2011.
- RF Governmental Resolution No. 442 dated 04.05.2012 "On the Functioning of Retail Markets for Electric Power, the Full and/or Partial Restriction of Electric-Power Consumption Mode", establishes the legal foundations for the functioning of electric-power retail markets.
- RF Federal Tariff Service Order No. 20-e/2 dated 06.08.2004 "On Approval of the Methodology Instructions for the Calculation of Regulated Tariffs and Prices for Electric (Thermal) Power on the Retail (Consumer) Market" is intended for the calculation, using the economically justified cost method, of the levels of regulated tariffs and prices on the retail (consumer) market for electric power (capacity) and thermal power (capacity).

Also, in 2019, the Government of the Russian Federation adopted the spatial development strategy of the Russian Federation for the period up to 2025 (Approved by order of the Government of the Russian Federation of February 13, 2019 No. 207-p.)

On February 2, 2019 the action plan to accelerate the growth rate of investment in fixed assets and increase to 25% their share in gross domestic product was adopted by the Chairman of Government (Approved by the Chairman of the Government of the Russian Federation D. A. Medvedev 02.13.2019 No. 1315p-P13).

The above list is not exhaustive but reflects the basic foundation of federal law in this area. At the same time, despite the rather serious regulatory framework that governs the sector, it would not be accurate to say that the current system of laws regulating the energy sector is ideal or sufficient to allow its administrators, including judges, to effectively apply the proper laws and sub-statutes in the course of their professional activity.

Judicial decisions, court judgments, results of public enquiries

It is hardly possible to detect any notable changes in the jurisprudence of Russian courts in 2018–2019. At the level of higher courts, only two decisions were adopted which, one way or another, dealt with energy law issues:

The Supreme Court of the Russian Federation declared the ban on private security activities in respect of electric power facilities invalid, regardless of the category of the object (decision of the Judicial Board on Administrative Cases of the Supreme Court of the Russian Federation dated April 26, 2019 No. AKPI19-87).

The Supreme Court of the Russian Federation published the text of the judicial act on the issue of determining the total period of unaccounted-for electricity consumption (determination of the Supreme Court of the Russian Federation of 05.23.2019 No. 309-ES18-24456). The main conclusion: when establishing the fact of unaccounted-for electricity consumption, the total period of unaccounted consumption should be determined from the date of the previous check of the meter (if it was carried out and the corresponding date does not exceed 12 months), or from the date no later than which the check of metering devices should be carried out (if it has not been carried out and/or the check date is beyond 12 months) until the date of the fact and the act of unaccounted consumption is revealed.

The Supreme Court of the Russian Federation prepared in full a judicial act on the distribution of the burden of proof of the fact that a consumer did not fulfil the obligation to preserve seals on an electricity meter (determination of the Supreme Court of the Russian Federation of 05.23.2019 No. 309-ES18-26293). The main conclusion: the fact that the consumer has not fulfilled the obligation to preserve the seals on the electricity meter is subject to proof by the guaranteeing supplier and/or network organisation.

Decision of the FAS Russia Board of Appeals on 01.01.2019 in case No. 04-05 / 01-2018, which concluded that the calculation of the cost of electricity at an unregulated tariff in relation to a social facility entitled to purchase electricity at a regulated tariff (for the category of consumers "population"), may be recognized as abuse of a dominant position by the guaranteeing supplier.

Major events or developments

On January 29, 2019, Order No. 45 "On approval of the activity plan of the Ministry of Energy of the Russian Federation for the period 2019–2024" was accepted.

In accordance with the Activity Plan, the objectives of the Ministry of Energy for the next five years will be:

- High-quality provision of the needs of the domestic market in energy products, energy and raw materials.
- Improving the energy and environmental efficiency of Russian energy, expanding the scale of innovation activity.
- Changing the approach to the system of relations and pricing models in the field of heat supply, creating economic incentives for the effective functioning and development of centralised heat supply systems.

- The introduction of advanced and digital technologies in the fuel and energy complex, as well as the effective implementation of the powers vested in the Ministry of Energy of Russia.

This event is crucial for the country's energy policy, because it establishes goals and objectives.

Proposals for changes in laws or regulations

In conclusion, it should be noted that current legal regulation of the fuel-and-energy complex is patchwork in nature and predicated on the lack of an overarching law (on energy) that would establish the basic principles and approaches to regulating relations in the electric-power, nuclear industry, coal industry and oil & gas industry complexes.

Each sector in the broader fuel-and-energy complex is governed by its own separate law (laws) and the sub-statutory acts adopted in its (their) furtherance. This approach to legal regulation creates conditions for the uneven application of the requirements of these laws, and consequently for the non-achievement, or only partial achievement, of the goals and objectives envisioned thereby.

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South Africa

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Overview of the current energy mix, and the place in the market of different energy sources

The energy mix in South Africa is made up of renewables, gas, coal, hydroelectric and nuclear. Electricity generation is undertaken primarily by state-owned power and utilities company Eskom, however increasingly by independent power producers. The transmission of electricity is undertaken by Eskom and electricity distribution (the final delivery of electricity to end users) is currently undertaken by Eskom together with various local municipalities. South Africa is heavily reliant on coal based energy sources, which generated 39,126 MW of the country's 51,981 MW installed capacity in 2018 – approximately 75%. At present, hydro, pumped storage, PV and wind sit at approximately 4%, 5.5%, 2.8% and 3.8% of installed capacity respectively, while nuclear remains an auxiliary power contributor, providing 3.5% of installed capacity.

Changes in the energy situation in the last 12 months, which are likely to have an impact on future direction or policy

<u>Change in ministerial responsibility</u>

On 29 May 2019, President Ramaphosa (the President) announced the appointment of a reconfigured national executive following the 2019 South African general elections. The President committed to a process of further reforms to "promote coherence, better coordination and improved efficiency" of government. Accordingly, the Department of Mineral Resources and the Department of Energy are to be merged into a single department named the Department of Mineral Resources and Energy (DMRE). The previous Minister of Mineral Resources, Mr Gwede Mantashe (Minister) has been appointed as the Minister responsible for this new consolidated department.

<u>Unbundling the national utility</u>

On 7 February 2019, the President announced that Eskom would be unbundled into three separate state-owned entities, responsible for generation, distribution and transmission respectively. The need for unbundling stems from the poor financial, structural and operational performance of Eskom. The decision to unbundle Eskom follows a recommendation from a President-appointed task team comprising experts in the electricity sector, established to provide recommendations on improving Eskom's performance. The task team found that the unbundling of Eskom would assist in the allocation of costs and responsibility within the national utility.

Unbundling involves the separation of energy production activities from transmission and distribution. Eskom will undergo a form of legal unbundling, which will separate the State utility into three separate legal entities. These entities will be owned and controlled by an Eskom holding company. It is expected that this will also allow for and necessitate the separation of bookkeeping across the energy generation, distribution and transmission entities. Eskom's largest source of debt relates to coal purchases and plant maintenance, which falls into the generation component of the energy supply chain. Separate bookkeeping of the respective entities would free Eskom's transmission and distribution entities from this historic debt, and enable each entity to borrow money, secure debts and raise investments separately from one another.

It is uncertain whether the unbundling of Eskom will create a more competitive environment for Independent Power Producers (IPP) to enter and participate in the electricity market. Currently, Eskom's transmission branch has a propensity to give its own generation plants preferential access to the grid. Because the three entities for generation, distribution and transmission will all be state-owned, it is unlikely that unbundling will result in greater private participation in the energy sector. On the contrary, should the unbundling be successful in revitalising Eskom, IPPs may struggle to compete with a fully functional state utility (supported by tax revenue and government administration).

Developments in government policy/strategy/approach

Integrated Resources Plan

The South African Integrated Resource Plan (IRP) is an electricity capacity plan, which sets out an indication of the country's anticipated electricity demand, how such demand is to be addressed and the cost thereof. In terms of the Electricity Regulation Act, 4 of 2006 (ERA), the National Energy Regulator of South Africa (NERSA) is required to issue rules designed to implement the Integrated Resource Plan. The IRP hence provides insight into the development of the nation's energy mix.

On 6 May 2011, the Department of Energy released the Integrated Resource Plan 2010–2030 (IRP 2010) in respect of SA's forecast energy demand for a 20-year period from 2010 to 2030. To date, the Department of Energy has implemented IRP 2010 by issuing Ministerial Determinations in accordance with section 34 of the ERA. The IRP 2010 is a living plan intended to be updated by the Department of Energy, although no such update has been formally published to date.

A review has been necessitated by a number of changes in the assumptions utilised in the IRP 2010, and an updated draft Integrated Resource Plan 2018 (Draft IRP) was released by former Minister of Energy, Jeff Radebe on 27 August 2018 for comment by the public.

The Minister has subsequently announced that the Draft IRP is in the process of being finalised and will be tabled before Cabinet for approval. During an interview in August 2019, the Minister said that, although nuclear energy generation has been de-emphasised, the Draft IRP, once final and published, will make provision for use of modular nuclear technology. The Minister added that nuclear energy generation would compete with other power sources to replace energy capacity, which will be decommissioned in the medium to long term. Accordingly, the timelines for any nuclear build will become clearer once the Draft IRP is approved.

The Draft IRP contemplates the following additional capacity:

- 1,000 MW of coal-generated electricity;
- 2,500 MW of hydro-generated electricity;
- 5,670 of solar PV-generated electricity;

- 8,100 MW of wind-generated electricity; and
- 8,100 MW of gas-generated electricity.

It is notable that the Draft IRP includes capacity allocation for solar photovoltaic, wind (onshore), embedded generation and gas. It excludes nuclear and solar CSP and any new coal generation capacity.

Coal

As noted above, the Draft IRP includes provision for 1,000MW of coal-to-power generated electricity in 2023–2024 based on the two procured and announced coal projects under the Coal Baseload IPP programme. South Africa is committed to the efficient use of its coal reserves through the employment of clean coal technologies, and coal remains of high strategic importance due to the significant number of jobs the industry provides. Notwithstanding this, these two projects may struggle to reach financial close and implementation as a result of funding and environmental challenges (especially within the market context of major private sector investors favouring environmentally friendly investment options).

Renewable energy

South Africa's renewable energy industry is in its infancy, but growing. South Africa has successfully implemented four rounds of independent power procurement under its renewable independent power producer programme (REIPPP). After a delay of almost two years, 27 new power purchase agreements under REIPPP rounds 3.5 and 4 were signed on 4 April 2018. Furthermore, financial close in respect of round 4 and 4.5 projects was reached on 31 July 2018. The continued development of the renewable energy sector has provided much-needed investment in South Africa and it is hoped that the commencement of these 27 projects will catalyse growth in related industries (primarily the construction industry). The Draft IRP contemplates renewable capacity coming online in 2025, which clearly indicates a delay in the scale and pace with which the bid windows have been implemented to date. The Draft IRP recommends a least-cost plan for the implementation of renewable energy capacity, with the retention of annual build limits to provide a smooth rollout and help sustain the industry.

Gas

It is clear from the Draft IRP that gas-based power generation will be a significant part of the energy mix in the future: 8,100 MW of new additional capacity is projected to be procured, with a total contribution of 11,930 MW by 2030. Gas-based power generation will account for approximately 16% of installed capacity mix by the year 2030.

In July 2019, South African state-owned rail, port and pipeline company, Transnet, announced that it had entered into a US$2 million cost-sharing agreement with the World Bank International Finance Corporation (IFC). The purpose of the agreement is to conduct a study concerning the feasibility of liquefied natural gas (LNG) storage and a regasification terminal in Richard's Bay. A special purpose vehicle (SPV) will be established for the purposes of developing the terminal. This SPV will comprise private investors, who will hold a majority stake holding, together with Transnet and other state-owned companies. The rationale for the SPV is to encourage private public partnerships in the natural gas sector. The study will also focus on the future use of Transnet Pipelines for the development of inland natural gas transmission and the establishment of virtual LNG pipelines. All these facilities are earmarked to become operational by 2024, provided Transnet obtains the necessary regulatory approvals in this regard. It is anticipated that the expansion of natural gas networks in South Africa will promote access to sustainable, secure and affordable natural gas for consumers.

Embedded generation

The Draft IRP has allocated 200 MW *per annum* to embedded generation for own use of between 1 MW and 10 MW, commencing in 2018. A generation licence will be needed to undertake the activities listed in Appendix E to the Draft IRP which, depending on each use-case, may apply to small-scale embedded generation as well. Licensing is facilitated by NERSA, and accordingly the accuracy of these predictions depends in part on NERSA's administrative capacity.

Hydro

Hydro-electrical power generation is envisaged to come online in the year 2030, in accordance with South Africa's commitments under the RSA–DRC treaty on the Inga Hydro Power Project. This is in line with South Africa's commitments as set out in the National Development Plan to partner with regional countries.

Developments in legislation or regulation

The Independent Management Operator Bill

The announcement of Eskom's restructure has called for the reconsideration of the Independent Market Operator Bill (IEMO Bill) in Parliament. The IEMO Bill (previously called the Independent System and Market Operator Bill) was first introduced by the Department of Energy in 2011 and provides for the establishment of an Independent Market Operator (IEMO), which will be tasked with the operation of the national grid as well as the purchase and sale of electricity from generators to consumers.

While the Bill was withdrawn in 2014, Democratic Alliance Member of Parliament published a notice of intention to re-introduce the Bill in the Government Gazette in 2019. The IEMO will carry out its operation duties by dispatching all generation plants into the national grid. In addition to operation, the IEMO Bill also confers ownership of the grid on the IEMO, with Eskom retaining ownership of the generation arm. The IEMO Bill will be introduced to Cabinet in the second half of 2019; however, it is likely that the Bill will undergo much political scrutiny given its potential impact on Eskom's monopoly.

Should the IMEO Bill be successfully promulgated, the establishment of an independent grid owner and operator would be a significant boost for renewable power generators in South Africa.

Judicial decisions, court judgments, results of public enquiries

Electricity prices and transmission tariffs

In 2019, the Constitutional Court handed down judgment concerning a decision of the National Energy Regulator of South Africa (NERSA) to approve the maximum gas price and transmission tariff of Sasol Gas Limited (Sasol). As the first gas producer active in the country, Sasol has held a monopoly over the South African gas market. To better facilitate competition in the gas market, maximum gas prices and its transmission tariffs are approved by NERSA. However, such decisions are usually based on applications made by Sasol as the gas producer.

Following approval by NERSA of an application by Sasol in respect of applicable maximum prices, and implementation thereof, a group of seven industrial gas users challenged the decision on the basis that they were required to pay significantly higher prices in respect to their gas use as a result. The applicants applied to review and set aside NERSA's decision, on the basis that the process of regulating a monopolist's prices must be rational and reasonable in terms of South African Administrative Justice law.

The Constitutional Court held that because NERSA had failed to consider the marginal costs of Sasol in the process of determining maximum and tariff prices, its decision was irrational and unreasonable. Accordingly, the court found in favour of the applicants, and overturned NERSA's decision.

Fracking technical regulations

Between 2008 and 2010, three applications were made in terms of the Mineral and Petroleum Resources Development Act 28 of 2002 (MPRDA) to explore shale gas through hydrolytic fracturing (fracking) in the Karoo. Following a general moratorium on the granting of subsequent petroleum right or permit applications over the Karoo, a further moratorium was implemented in February 2014, restricting the approval of applications which provided for use of hydraulic fracturing until such time as technical regulations had been promulgated regulating the practice.

To determine the environmental and social implications of fracking, the Minister of Mineral Resources set up an inter-ministerial task team and subsequently a monitoring committee. The task team and monitoring committee made certain recommendations to Cabinet pertaining to fracking. Upon these recommendations, the Minister of Mineral Resources promulgated technical petroleum regulations in 2015 (Technical Regulations).

The publication of the Technical Regulations was challenged in two concurrent applications (in each of the Eastern Cape and the Pretoria North Gauteng High Courts), on the basis that: (i) such promulgation had been procedurally unfair; and (ii) the Minister of Mineral Resources did not have authority to promulgate the regulations under the Mineral and Petroleum Resources Development Act, 28 of 2002.

The applicant succeeded in the matter brought before the Eastern Cape High Court, and obtained an order setting aside the Technical Regulations in their entirety. Conversely, the Pretoria North Gauteng High Court dismissed the application brought before it and found that the Minister of Mineral Resources was authorised to promulgate the regulations and that its promulgation had been fair.

The two matters were consolidated and heard by the Supreme Court of Appeal (SCA) in July 2019, wherein the SCA concurred with the Eastern Cape High Court and held that the publication of the Technical Regulations had been *ultra vires*. The Court found that the Minister did not have the power to make regulations of an environmental nature, including many provisions of the Technical Regulations. The SCA found that, as those provisions of the Technical Regulations which the Minister published unlawfully could not be separated from the remainder of the provisions of the Technical Regulations without rendering them ineffective, the Technical Regulations had to be set aside in their entirety.

The Technical Regulations are accordingly of no force or effect and will need to be redrafted in a lawful manner. As such, plans for exploration by hydraulic fracturing in South Africa remain suspended pending the redrafting and promulgation of appropriate Technical Regulations.

Major events or developments

Ministerial deviation from Integrated Resources Plan in respect of small-scale embedded generation

On 31 May 2019, the Minister of Energy at the time, Jeff Radebe, granted a deviation from the existing IRP 2010 for the licensing of small-scale embedded generation renewable energy projects ranging above 1MW to 10MW. Small-scale embedded generation refers to the production of electricity from power stations that are directly connected to the distribution network.

In terms of the Energy Regulation Act ERA, no person may operate any generation facility without a licence issued by the National Energy Regulatory Authority (NERSA). The ERA furthermore provides that an application for such a licence must include evidence of compliance with the IRP 2010 or provide reasons for any deviation for the approval of the Minister.

The impact of the deviation granted by the Minister is that NERSA may now grant licences to such small-scale embedded generation projects without the Minister needing to provide any further approval. The permitted deviation applies to all projects generating up to an annual ceiling of 500 MW. NERSA has emphasised that that applications for these small-scale projects will not automatically be approved and will still have to undergo the prescribed registration procedure and evaluation process in terms of the IRP.

Rollout of energy storage

In 2018, it was confirmed that Eskom would be deploying a large-scale distributed energy storage project across South Africa funded by the International Bank for Reconstruction and Development, the Clean Technology Fund and the African Development Bank. The first phase of the project involves 800-megawatt hours (MWh) of distributed energy storage to be installed at Eskom's 48 distribution sites in the Eastern Cape, Northern Cape, Western Cape and KwaZulu-Natal respectively.

Requests for proposals for the first phase were set to be released to the market by mid-2019 (although these are still pending as of date of publication). The second phase involves an aggregate amount of 640 MWh of distributed battery storage, with 60 MW of distributed Solar PV to be installed in all nine South African provinces by the end of 2021. The storage facilities that will be used in the project comprise container-encased grid-scale electrochemical batteries. The facilities store electricity from power plants and can be used when demand arises.

In 2019, it was confirmed that Eskom, together with the World Bank and ATA Insights, would be hosting a webinar regarding Eskom's storage project. The will allow interested parties to discover large-scale battery investment opportunities and to provide recommendations on the manner in which the project should be carried out.

Energy storage could circumvent the need for diesel and other fossil fuels for peaking and baseload power, as well as increase South Africa's ability to incorporate renewable energy into its energy mix. Currently, there is no legislation which specifically regulates energy storage. Energy storage facilities would, however, need to comply with South Africa's environmental legislation.

Proposals for changes in laws or regulations

Draft Petroleum Resources Development Bill

As of the date of publication, the Minerals and Petroleum Resources Development Act 28 of 2002 (MPRDA) governs the upstream petroleum and mining industry. Seven years ago, the Mineral and Petroleum Resources and Development Amendment Bill (Bill) was published for public comment as an amendment to the MPRDA.

Following passage through the South African National Assembly on 16 January 2015, the President of South Africa at the time, acting in terms of section 79(1) of the Constitution, referred the Bill back to the National Assembly due to reservations the President had as to the constitutionality of the Bill (including that inadequate public participation had been provided for in its publication).

Accordingly, and in order to remedy the defects identified by the President, the National Council of Provinces Select Committee on Land and Mineral Resources (the Select Committee) held an extensive public participation process during 2017 which involved public hearings on the Bill held in every province in the country, and which allowed for the submission of written submissions by members of the public in respect of the Bill.

On 20 September 2018, the Minister of Mineral Resources announced his decision to withdraw the Bill from parliament. The Minister then announced that that a separate legislative framework for the upstream oil and gas sector will be developed and that this bill will be fast-tracked.

As it currently stands, the target date for the passing of the Petroleum Bill into legislation is early/mid 2020. Before the Petroleum Bill can be passed into law, the Bill will undergo a process of public participation and deliberation between Parliament and the Executive. A draft of the Bill has not yet been released for public comment, and as of yet we cannot comment as to the provisions of the Bill or changes to the legislative regime.

Draft Financial Provisioning Regulations

In terms of the Financial Provisioning Regulations published under the National Environmental Management Act 107 of 1998 (NEMA), financial provision must be made by the holder of an exploration or production right granted under the Minerals and Petroleum Resources Development Act 28 of 2002 (MPRDA) for rehabilitation, closure and ongoing post-decommissioning management of negative environmental impacts related to the activities conducted under such right. The Financial Provisioning Regulations are however undergoing a process of amendment and revision and a new version of the regulations is expected to be promulgated towards the end of 2019.

In May 2019, the Minister of Environmental Affairs published the 'Proposed Regulations Pertaining to the Financial Provision for the Rehabilitation and Remediation of Environmental Damage Caused by Reconnaissance, Prospecting, Exploration, Mining or Production Operations' for public comment in the Government Gazette (draft Financial Provisioning Regulations). Important aspects of the proposed amendments include a requirement that provision is made upfront for remediation and decommissioning costs in relation to activities which are planned to be performed over a 12-month period from the date of assessment, regardless of when such remediation and decommissioning costs are actually incurred, as well as a requirement that holders annually update and reassess existing financial provisions set aside. Furthermore, the draft Financial Provisioning Regulations provide for changes to the financial vehicles which may be used in the setting-aside of funds.

Holders of rights who applied for exploration or production rights prior to 20 November 2015 (when the Financial Provisioning Regulations were promulgated) will be afforded a transitioning period expiring in February 2024 to comply with the draft Financial Provisioning Regulations (once promulgated).

Challenge to the Single-Buyer Model

South Africa currently uses a single-buyer model of electricity, whereby Eskom has the exclusive right to purchase power from Independent Power Producers (IPPs) and transmit this power through the national grid for distribution. This model has, however, been challenged by the City of Cape Town municipality (the City) which is currently seeking to procure electricity directly from IPPs for the purposes of resale. Section 34 of the Electricity Regulation Act 4 of 2006 (ERA) states that the Minister may, in consultation with NERSA, determine the types and quantity of electricity that is to be generated and the manner in which the electricity generated may be sold. The City has lodged an application seeking a court declaration that ministerial consent is not required for an IPP to sell electricity to a municipality. In the alternative, the City has submitted that if ministerial consent is required, s 34 of the ERA is to be declared as unconstitutional.

Litigation is still pending and it is uncertain if the City will be successful in challenging the prevailing single-buyer electricity model.

Should the City be successful, the liberalisation of the energy market, and the introduction of hundreds of potential new buyers through local municipalities, will be a significant boon for the burgeoning renewables sector.

Conclusion

While the impact of Eskom's unbundling on South Africa's energy landscape is uncertain, the imminent publication of the updated IRP, and the promotion of small-scale renewable energy generation, are positive steps toward diversifying South Africa's energy mix. The provision of energy storage is also a key factor in ensuring energy security in the country. However, a diversified energy mix requires significant investment. Government has taken steps towards facilitating a competitive and investor-friendly regulatory environment; however, it may take time before the sector sees significant change.

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Overview of the current energy mix, and the place in the market of different energy sources

Swedish energy production is – and has been for a fair amount of time – dominated by carbon dioxide-free energy sources, mainly hydropower and nuclear power. These two energy sources, together with biofuels and fossil fuels, are the main energy sources within the Swedish energy system. Over the last 30 years, there has been a steadily increasing supply of biofuels while during the same time span, the supply of fossil fuels has decreased substantially. The reason for this is mainly because residential buildings and facilities are rarely heated by means of oil nowadays.

Total energy use in Sweden has seen a general decrease since the year 2000. This is mostly a result of the decommissioning of several nuclear reactors, which has decreased energy losses in the nuclear energy domain. However, the total energy input amount shows notable stability over time and has, since the mid-80s, hovered between 550 and 600 TWh. In 2017, the total domestic energy supply was 565 TWh. Sweden's energy use is commonly divided into three different user sectors: the industrial sector; the transportation sector; and the residential and service sector. The industrial sector primarily relies on electricity and biofuel, while the transportation sector is dominated by fossil fuels. Energy usage within the residential and service sector is dominated by district heating, electricity, oil and biofuels.

In relation to Sweden's total electricity consumption, electricity produced from renewable sources such as hydropower, biofuels, wind power, and solar installations, accounts for around 65%. Moreover, around 80% of Sweden's total electricity demand is met through hydro- and nuclear power. Hydropower is the dominant energy source, accounting for 66.9 TWh, or around 45% of the total electricity production. Furthermore, a fair share of the energy demand is met by imported energy, mostly for electricity production in nuclear reactors, but also fossil fuels.

A long-standing endeavour of Swedish energy policy, which during the last decade has cemented itself as commonplace, is to actively promote the use of renewable sources. As a corollary to this overarching pro-renewables approach and concurrent rapid technological development, Sweden has managed to establish a relatively low fossil-fuel dependency. During the course of the last two decades, total fossil-fuel usage has decreased significantly, especially so in the residential sector. The latter can, to a noteworthy degree, be attributed to the transition to geothermal solutions for residential heating, as opposed to traditional oil furnace heating. Geothermal and district heating now account for almost 90% of energy usage for the heating of apartment buildings.

Furthermore, within the industry sector, fossil fuel utilisation has undergone a significant general decrease. This notwithstanding, fossil fuels still play a conspicuous role within the transportation sector. Nonetheless, we have witnessed a clear trend, even in transportation, of shifting to renewables. Since 2010, carbon dioxide emissions from transportation have decreased by 19%. In 2018, the use of biofuels (predominantly biodiesel) in the transportation sector accounted for 23% of total fuel usage. Moreover, and as will be elaborated further below, the current legislative environment will most likely further accelerate this already rapid development going forward.

The palpable pro-renewables wave is leaving its mark also in the realm of electricity production by paving the way for a forceful shift towards a wider range of green solutions. During recent years, we have witnessed a notable increase in wind farms built and, as of today, Sweden constitutes one of Europe's larger markets for wind power. In 2018, the total amount of wind turbines amounted to around 3,600. Likewise, wind power accounted in 2018 for 16.6 TWh, with an installed capacity of around 7,300 MW.

The 2018 numbers nonetheless reveal a decrease in wind power-produced electricity from the previous year, which, however, can be ascribed to yearly variations. In 2018, the Swedish Wind Energy Association declared that the amount of wind power capacity planned to be installed is at a record high. There are currently 123 permits for wind power approved, corresponding to 3,119 wind turbines not yet constructed. This corresponds to an installed capacity of 11,000 MW and a yearly production of 33 TWh. Two main drivers for the rapid expansion of wind farms are: lower development costs (e.g. thanks to new and cheaper technologies); and the recently approved extension of the Swedish Electricity Certificate System (a market-based support system for renewable electricity production).

In addition to wind power development, extensive solar power installations are taking place in Sweden on a continuous basis. Between 2017 and 2018, the number of photovoltaic cell facilities connected to the power grid increased by around 67%. Moreover, the total amount of constructed photovoltaic cell facilities built during 2018 amounted to 10,200 and the total amount of facilities is currently around 25,500. Solar power facilities account for an installed capacity of around 411 MW, which is 78% higher than the previous year.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The Swedish energy system has traditionally rested on large-scale and centralised electricity production, stemming primarily from hydropower and nuclear power. A steady and controllable flow of electricity between consumers and producers has characterised the market. However, as noted above, more solar- and wind-power installations have been put in place during recent years, and currently account for a larger amount of total electricity production.

This, in conjunction with the fact that total base load generation has decreased (mainly because of the ongoing decommissioning of nuclear reactors), necessitates a well-balanced energy output. In light of this, the need to achieve a rational balance between production and consumption renders higher demands for flexibility in the system than used to be the case. The issue of system flexibility interlinks with the necessity of creating adequate delivery reliability among providers of electrical energy. However, notwithstanding regulatory requirements on network operators to ensure timely deliveries and to minimise downtime, the transition from centralised electricity production, in combination with a relatively high incidence of out-dated and insufficiently equipped grid connections in the electricity system, has given rise to an increased risk of shortages in power capacity.

The decrease in base load generation also affects the electricity supply to a significant extent. This is true despite major wind and solar power installations made during recent years, as these energy sources, in comparison with nuclear power, have lower availability. In the spring of 2019, the Swedish Energy Agency published a short-term prognosis for the Swedish energy situation between 2018 and 2021. The prognosis highlights that the ongoing decommissioning of nuclear reactors will result in a decrease in the energy supply during the coming years.

The decrease in base load generation and the increased need for flexibility in the system, with the accompanying implications for Sweden's power capacity and electricity supply, form part of a long-standing trend in Sweden's energy market. However, more recently, several major actors in the Swedish energy market have warned of a significant worsening of the power capacity situation triggered by legislative developments, resulting in an imminent shortage in power capacity in the energy market, and giving rise to major implications for the Swedish economy.

As will be further elaborated below, a monopolised system governs the Swedish electricity network market (since it comprises several natural monopolies) which, *inter alia*, restricts the amount of revenue that electricity network operators can recover over a four-year regulatory period (so-called "revenue caps"). In April 2019, the Swedish Government proposed new legislation aimed at restricting network operators from carrying over unused deficits of revenue caps (i.e. revenue backlogs) for more than one regulatory period. This proposal has triggered a heated debate and received fierce criticism from Sweden's network operators and several other major stakeholders in the Swedish electricity market.

Following the announcement of the Government's proposal, one of Sweden's largest network operators proclaimed that the implementation of the new legislation would force the company to decrease its investment rate in the power grids by 40%. Moreover, the company stated that the largest cities of Sweden are now facing a dire power capacity shortage, where the power grids are not properly equipped to handle an imminent increase in energy demand on the Swedish market and new demands of the grids, for example, due to a new type of energy-intensive customer (e.g. data centres) and energy-consuming equipment such as electrical car-charging stations. Additionally, one of Sweden's largest producers of bread and bakeries announced the cancellation of major expansion plans due to an anticipated lack of sufficient power capacity in southern Sweden due to improperly equipped grid connections.

Developments in government policy/strategy/approach

An event of significant importance in the political arena in the last few years is the framework agreement on Swedish energy policy. The agreement, which is built on broad political consensus, was executed in June 2016 by five of the eight political parties represented in Parliament. By combining the three pillars of energy cooperation in the EU, *viz*. ecological sustainability, competitiveness and security of supply, the agreement constitutes a strategy for a controlled transition to an entirely renewable electricity system, aiming towards a 100% renewable electricity production by 2040. The framework agreement exercises significant influence on Parliament, and has developed to become a cornerstone of Swedish energy legislation.

Policy-wise, the majority of Swedish political parties are united in a general aspiration to accelerate the reduction of carbon dioxide emissions. This is evident, not least, by the fact that the framework agreement reaches across existing party blocks. However, as described above, the ongoing decommissioning of nuclear reactors has led to a general decrease in Sweden's energy supply, which is expected to continue over the coming years. With reference to this development, the Swedish Moderate Party (Sw. *Moderaterna*) and the Christian Democrats (Sw. *Kristdemokraterna*), announced during the spring of 2019 that they would withdraw from the framework agreement unless improved conditions on the nuclear market are recognized within the agreement as a necessary means to reach Sweden's ambitions to decrease carbon-dioxide emissions (which is currently not the case). This announcement sheds light upon a notable disagreement between the signatories to the framework agreement in relation to the future of nuclear energy, which may compromise the viability of the framework agreement as a long-term, cross-party-blocks policy document. Nonetheless, the willingness of Sweden's political parties to accelerate the decrease in dependency on carbon-based energy solutions through intervening legislative measures will likely remain the same, notwithstanding the survival of the framework agreement.

The Swedish parliamentary elections took place in September 2018. Following the election results and a period of parliamentary uncertainty, a new Government was formed consisting of the Social Democratic Party (Sw. *Socialdemokraterna*) and the Green Party (Sw. *Miljöpartiet*), with support from the Center Party (Sw. *Centerpartiet*) and the Liberals (Sw. *Liberalerna*). A cross-party-block agreement (the so-called "January Agreement") constitutes the basis of the policy strategy agreed between the political parties forming the new Government on the one side, and the Center Party and the Liberals in their capacity of supporting parties on the other. The January Agreement carries with it numerous policies and declarations of intent, which will affect the energy market going forward.

The January Agreement stipulates as an overarching intention that Sweden is to become the world's first fossil-fuel-free country and that, by the year of 2045, Sweden's net emission of greenhouse gases will be reduced to zero. Additionally, the January Agreement contains, *inter alia*, the following ambitions:

The Government will develop and streamline existing climate investment programs. This includes a revision of all relevant legislation in order to enable the climate policy goals to have full effect (Governmental investigation planned during 2019).

Increased infrastructure expansions and investments in biogas distribution will be carried out in order to facilitate fossil-free charging and refuelling. In addition, the agreement stipulates an intention to, by 2030 (pending approval from the EU Commission), implement a general prohibition on sales of newly manufactured diesel and petrol-operated cars.

Sweden will also actively promote the abolition of international conventions preventing taxes on fossil fuels for aircraft, as well as an EU-level climate law to enforce the United Nations Paris Agreement.

The January Agreement constitutes concretization – and in certain respects an expansion – of the ambitions set out in the framework agreement on Swedish energy policy, and the January agreement clearly indicates that Sweden's climate policy will be one of the new Government's top priorities during the remainder of the current term. We foresee that the January Agreement will have a significant impact on energy policy and legislation during coming years.

Developments in legislation or regulation and proposals for changes

Regulatory developments regarding revenue caps

Ever since 2012, Sweden's Energy Markets Inspectorate (the Ei) has regulated the revenues of electricity network companies over a four-year period. Revenue caps limit the amount of revenues that network operators may recover from their operations during one regulatory period. The principal rule is that revenues should cover the reasonable costs of running a network as well as providing a reasonable return on the capital invested. The regulation regarding revenue caps has been the subject of heated debate, especially in relation to the concurrent issue of security of supply, which constitutes one of the variables for deciding the scope of the revenue caps.

In August 2018, the former Government enacted a new ordinance changing the rules regarding the determination of revenue caps, which will come into force as per the next regulatory period starting in 2020. The background of the change was that major electricity network operators in Sweden had been able to raise network tariffs in a manner that the former Government deemed unacceptable, seeing as the rises implemented had not been met with a corresponding increase of investments in the electricity grid. Additionally, during the first and second regulatory periods, the network operators appealed more than half of the decisions made by the Ei, which – in the eyes of the former Government – indicated a pressing need for more rule clarity.

The essence of the provisions of the new ordinance pertain to how to set the discount rate (the WACC) used for calculating the revenue caps. With respect to the current and the previous regulatory periods, the Ei has been relatively free to decide the WACC, something which has resulted in protracted and complex court proceedings. Now, the new ordinance specifies in detail how various part of the WACC calculation should be carried out. Moreover, in addition to creating a more tangible regulatory framework, the provisions aim to establish more reasonable distribution charges.

The former Government stated in August 2018 that the change might result in a situation where a majority of the customers currently paying fees in accordance with a comparatively high rate will be able to secure significantly lower fees.

In June 2019, the Ei issued the first four decisions regarding revenue caps for the electricity network companies for the period 2020–2023. The decisions fixed the discount rate to 2.16% real before tax. This discount rate is significantly lower than the 5.85% applied during the current regulatory period (2016–2019). Thus, the decisions entail a significant restriction on permitted revenues and, concurrently, a decrease of network tariffs. The Ei will render the remaining decisions on a continuous basis during 2019.

Additionally in relation to revenue caps, the Swedish Ministry of Environment and Energy recently issued a memorandum suggesting revisions to the regulatory framework in relation to revenue caps for electricity network operators. The suggested legislation entails that electricity network operators will not be able to carry over unused deficits from the regulatory period 2012–2015 during the regulatory period 2020–2023.

As discussed above, because of these decisions by the Ei and the pending new legislation, we may experience a decrease in the investment willingness of the network operators, and in the prevailing interest among infrastructure funds and institutional investors to continue to make investments within this sector. In turn, from a long-term perspective, a decreased investment rate in the power grids may stifle investment willingness in companies whose anticipated expansion rate is contingent upon large-scale energy consumption, and may also have a negative impact on the general electrification trend with respect to transport and many other sectors.

<u>Reduction duty for increased usage of biofuel in petrol and diesel</u>

In July 2018, the so-called "reduction duty" came into force on the Swedish energy market. The legislation seeks to promote the use of biofuels by imposing an obligation on sellers of propellants to decrease emissions of greenhouse gases by way of mixing biofuels together with petrol or diesel fuel. Furthermore, the reduction duty constitutes a withdrawal from the previous strategy for increasing biofuel use, which was based on state subsidies. Concurrently, this entails that biofuels are taxed at the same rates as fossil fuels.

Nonetheless, the currently enforced reduction duty applies only until 2021. Accordingly, in June 2019, the Swedish Energy Agency published a memorandum containing a proposal as to how the reduction duty should be designed after the expiration of the currently enforced provisions, including relevant reductions levels, until 2030. By setting appropriate reduction levels, the proposal aims to reduce the greenhouse gas emissions stemming from domestic transportation by 70% by 2030 compared to the levels in 2010.

To achieve this goal, the Swedish Energy Agency proposes reduction levels to be implemented successively from 2021 to 2030. Thus, according to the proposal, the reduction level will in 2021 be set at 6.3% for petrol, and 24.6% with regard to diesel. From this point on, the reduction duty undergoes a successive yearly increase, rising by 2030 to 27.6% for petrol and 60% for diesel.

The proposal further latches on to the ambition set out in the January Agreement to reduce the net emissions of greenhouse gases by the year 2045. Thus, the Swedish Energy Agency proposes a reduction level by the year of 2045 fixed at 80.6% for petrol, and 92.9% for diesel.

From a short-term perspective, the reduction duty will likely lead to an overall increase in transportation costs. At the same time, the shift from state subsidies increases foreseeability for bio-fuel producers, which may have a long-term positive effect on the production rate.

Increased taxation on natural gas used for CHP

In early 2019, the Swedish Government announced a significant increase in taxation on fossil energy sources (mainly coal and natural gas) used to fuel energy production based on co-generation, or combined heat and power ("CHP"). In relation to natural gas, the new legislation entails an increase in taxation corresponding to 473% compared to current taxation levels; in other words, a notable increase.

The proposal has given rise to major controversy and criticism from several Swedish energy companies due to the anticipated implications for Sweden's electricity supply. One major Swedish energy company has stated that, due to dismantling of CHP facilities and a general decrease in CHP-based electricity production caused by the increase in taxation, 500 GWh of electricity will need to be supplied from other sources. Allegedly, this may result in significant shortages in electricity supply, mainly in Sweden's three largest cities.

Judicial decisions, court judgments, results of public enquiries

Rulings on revenue caps

During the course of recent years, there have been several court cases relating to revenue caps *vis-à-vis* the electricity network operators. As explained above, revenue caps regulate the amount of revenue that network operators may extract from their operations. A major series of court cases (the so-called "Referral Cases") relating to the second regulatory period was won by the network operators at the end of 2017, after the Administrative Supreme Court declined to try the Ei's appeal.

Since then, the Ei has increased the revenue caps by fixing the discount rate (based on the WACC-method) at 5.85%, which allowed the network operators to, in aggregate, charge fees up to SEK 8 billion more. However, as mentioned above, the Ei has recently issued decisions regarding the revenue caps applicable for the regulatory period between 2020 and 2023, significantly restricting the applicable discount rate and, consequently, the level of permitted revenues.

During recent years, the lower administrative courts published a number of additional decisions; however, this time relating to the extent to which a network operator may carry over unused deficits of the revenue caps (i.e. revenue backlogs) during the course of several regulatory periods. The Ei has interpreted the law in a manner that limits the number of regulatory periods during which a network operator may "save" non-utilised revenue caps.

During the spring of 2017, around 40 network operators appealed the Ei's decision, arguing that the opportunity to carry over revenue caps extends over at least two regulatory periods. In September 2018, the court ruled in favour of the appealing companies, and decided that operators who had not made use of the revenue caps during the regulatory period between 2016 and 2019 would be able to postpone their utilisation until the end of the next regulatory period, i.e. 2023. The Ei appealed the decision to the Administrative Court of Appeal, which rendered its decision in February 2019. The Administrative Court of Appeal ruled in favour of the network operators and thus allowed the network operators to carry over the relevant revenue caps for more than one regulatory period.

Nonetheless, the decision from the Administrative Court of Appeal will likely only carry weight in relation to previous regulatory periods. As discussed above, new legislation is planned to be implemented in relation to revenue caps for the period 2020–2023 and onwards. These rules aim to clarify that, going forward, network operators will not be able to carry over revenue caps for more than one regulatory period.

Rulings on depreciation of gas transmission lines

A similar turn of events has unfolded also on the gas side, i.e. in relation to Sweden's gas network operators. A significant factor for deciding the revenue caps for the gas network operators is the depreciation periods for gas transmission lines and measuring and control stations. In relation to the regulatory period 2019–2022, the Ei set the applicable depreciation periods at 50 years for gas transmission lines and 20 years for measuring and control stations.

Following a round of appeals against the Ei's decisions, the lower Administrative Court rendered a decision in June 2019. The lower Administrative Court decided in favour of the gas network companies. Thus, the court granted longer depreciation periods, *viz*. 90 years for gas transmission lines and 40 years for measuring and control stations. The Ei has announced that it will adjust the revenue caps for 2019–2022 accordingly.

Major events or developments

Throughout the past few years, we have seen significant changes in the energy markets as well as volatile energy prices. Moreover, rapid digital development has led to historically dominant energy companies facing stiff competition from new players attempting to advance into the energy domain with new, innovative solutions. These factors, among other things, have triggered a need for structural measures among the dominant actors on the energy market and, concurrently, a relatively strong and viable energy-related M&A market.

In this regard, an exciting development in the electricity domain is the Swedish start-up Northvolt's planned battery production in northern Sweden and Germany. Northvolt's mission is to initiate large-scale production of the world's greenest battery, with a minimal carbon footprint and the highest ambitions for recycling, to enable the European transition to renewable energy. For this purpose, Northvolt's plan is to build Europe's largest lithium-ion factory (a so-called "gigafactory") in northern Sweden in 2023. The factory has a planned capability of generating 32 GWh in battery capacity. In June 2018, Northvolt received necessary environmental permits for the initial stage of the project, and plans to begin production of the first section of the factory in 2020. The company has since sought to attract more investors, in addition to companies already involved, such as ABB, Siemens, Vattenfall, IMAS Foundation, BMW, and Scania to secure the continued funding of the project.

In June 2019, Northvolt announced that it completed yet another equity-funding round for USD 1 billion. Volkswagen Group was the lead strategic investor in the funding round and will, together with a consortium of financial investors led by Goldman Sachs, join Northvolt's list of shareholders. In addition to enabling the construction of the "gigafactory" in northern Sweden, the Volkswagen Group and Northvolt have agreed to form a joint venture aimed at constructing a battery cell factory in Lower Saxony, Germany.

Lastly, another notable event on the energy-related M&A market during 2019 is the anticipated sale of Öresundskraft, one of Sweden's largest municipally owned energy companies. The announced sale of the company, owned by Helsingborg municipality in southern Sweden, has allegedly attracted significant attention among many prospective domestic and international bidders. Upon completion, the transaction will likely constitute one of the largest acquisitions to occur on the Swedish energy market during the course of 2019.

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Switzerland

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Overview of the current energy mix, and the place in the market of different energy sources

Switzerland's final energy consumption totalled 854,300 Terajoules (TJ) in 2016. The energy mix consisted of motor fuels (34.2%), stationary fuels (16.1%), electricity (24.5%), gas (13.7%) and other (11.5%). The final sectoral consumption was split between transport (36.0%), households (28.2%), industry (18.2%) and services (16.6%).

While electricity demand in Switzerland can be met by domestic production, Swiss oil and gas demands fully depend on imports. This is due to the fact that Switzerland has no domestic production of crude oil and natural gas. Therefore, energy-related regulations in Switzerland are mainly focused on the electricity sector.

Electricity consumption reached 58.5 billion kWh (or 62.9 billion kWh, taking into account the losses due to transport and pumping for pump storage plants) in 2017. On the supply side, national production amounted to 57.3 billion kWh. The main source for electricity production is hydropower, which represented 59.0% of production in Switzerland. Moreover, electricity production in Switzerland consists of nuclear power (32.8%), non-renewable conventional thermal power (3.1%) and renewable energy other than hydropower (5.1%).

Switzerland aims to phase out nuclear power and to increase its electricity production from renewable energy sources, in particular from solar power. This process is known as the "Energy Strategy 2050". Renewable energy sources therefore benefit from state support. The main instrument for the promotion of electricity production from renewable energy sources is a feed-in tariff system, which has been revised recently as described below. The government's intention to "green" the national electricity production has been leading to a significant increase of electricity production from solar power since 2012. Today, solar power is the most important renewable energy source other than hydropower. However, solar power accounts for only 2.2% of the total electricity production in Switzerland and therefore still plays a minor role.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In general, Switzerland has a stable energy mix and the shares of oil, electricity and gas alter only slightly from year to year. With regard to electricity production, however, hydropower is under increasing pressure. There are external and internal reasons for the increasing pressure on hydropower.

Externally, overcapacities due to subsidies for renewable energy sources in several EU Member States (in particular, Germany), as well as faltering demand, have led to low prices in European electricity trading. The low electricity prices in the European electricity market have put Swiss hydropower producers in financial difficulties, as they are no longer able to cover their production costs. Since hydropower is a mainstay of Swiss electricity supply, the financial difficulties of hydropower producers calls for state support, which has been granted as described below.

Internally, the proposal of a temporary reduction of the "water royalty" (i.e. a compensation paid to the communities for the use of water), which accounts for up to 25% of production costs, did not receive majority backing in the consultation phase. Moreover, duties and taxes such as a 'renaturation tax' have been increased or newly introduced through federal legislation, which increases the financial burden for hydropower producers. Lastly, some cantons and communities refuse to renew water concessions and intend to take over hydro-electricity production from private producers.

These developments in the field of hydropower may have various policy impacts in the future, in particular in the field of trade policy. Internally, it is generally agreed that hydropower should remain the mainstay of Swiss electricity supply and thus shall be supported accordingly. However, there is disagreement on which measures suit best, as e.g., the revision on the "water royalty" shows. With regard to the external perspective, it remains open, to what extent Switzerland may keep up with the subsidy race in Europe, as EU Member States have been increasing subsidies for renewable energy sources (in particular, Germany).

In order to protect its hydropower producers from low electricity prices in Europe, Switzerland may take trade measures (such as an import tax on electricity produced from fossil energy sources). Moreover, Switzerland may question the consistency of certain EU subsidies for renewable energy sources with international trade agreements by invoking the state aid provision under the Swiss-EU Free Trade Agreement (art. 23), or by submitting a complaint with the World Trade Organization (WTO) against the EU regarding a violation of the Agreement on Subsidies and Countervailing Measures. However, whether Switzerland will use these options depends on political feasibility and opportunity.

Nevertheless, hydropower producers in Switzerland, in particular pumped-storage plants, may also benefit from the increasing electricity production from renewable energy sources in Europe. The restructuring of the electricity supply infrastructure throughout Europe, with increasingly irregular and distributed sources of supply, is leading to a Europe-wide increase in demand for storage. Pumped storage power stations allow spontaneous compensation for over-production or under-production from wind and solar energy sources and, if necessary, permit the temporary storage of electricity for days or weeks. In Switzerland, hydropower producers are able to provide a substantial number of pumped storage power stations. Moreover, a number of pumped storage power stations are under construction as well. Still, the total Swiss storage capacity can only meet a fraction of the Europe-wide demand for storage.

Developments in government policy/strategy/approach

In 2011, the Federal Council and Parliament, triggered by the Fukushima nuclear incident, decided to progressively abandon nuclear electricity production in Switzerland. As nuclear energy provides around 30% of total electricity production, the decision to phase out nuclear electricity production means a complete restructuring of the Swiss energy mix with regard to electricity production. This restructuring process is called the "Energy Strategy 2050". The Energy Strategy 2050 aims at replacing nuclear electricity production with renewable energy sources, and will be implemented in phases. An initial package of measures that aim to reduce energy consumption, increase energy efficiency and promote renewable energies such as water, solar, wind and geothermal power, and biomass fuels, has been introduced by the Parliament. In this regard, the Parliament has adopted new legislation, which was endorsed in a referendum on 21 May 2017. The new legislation will be described in more detail below. The further phases have yet to be elaborated, but it is intended to phase out the promotion of renewable energy.

As an essential link between production and consumption, networks are pivotal for electricity supply. Together with the Energy Strategy 2050, the Federal Council developed an "Electricity Grid Strategy". This strategy introduces a new legal framework for grid development. It aims at ensuring that grids are timely developed in order to secure a sufficient energy supply at all times. Measures include, e.g. the optimisation of approval procedures. The respective legislation was adopted by the Parliament in December 2017 and entered into force in June 2019.

With regard to gas, the Federal Council stated in early 2014 that it will examine the opening of the Swiss gas market. Moreover, the Federal Council intends to present a draft gas supply by the end of 2019, in order to update the existing Federal Act on Pipeline Systems for the Transport of Liquid or Gas Fuel, and to seek compliance with EU standards.

Lastly, Switzerland is interested in participating in the EU energy market, in particular in the electricity market. A mutual free market access would strengthen the position of Swiss electricity producers in the European electricity market and increase the security of supply. The integration of Switzerland into the EU electricity market is also important for a successful implementation of the Energy Strategy 2050. Therefore, Switzerland and the EU started negotiations on an electricity agreement in 2007. In 2010, the negotiations were extended and other energy sources such as gas were included. However, the conclusion of the electricity agreement is uncertain. Before granting further market access to Switzerland, the EU insists on concluding an institutional agreement, which should establish a general legal framework for Switzerland's participation in the EU common market. However, this agreement is controversial in Switzerland as it requires Switzerland to adopt EU legislation. Therefore, the institutional agreement has not been concluded yet.

Developments in legislation or regulation

In the context of the Energy Strategy 2050, the Federal Energy Act has been completely revised in order to introduce initial measures aimed at implementing the Energy Strategy 2050. The new Energy Act and the required amendments in related legislations were endorsed in a referendum on 21 May 2017. The new Energy Act and the correspondent Ordinances entered into force on 1 January 2018.

The new Energy Act introduces measures to reduce energy consumption, increase energy efficiency and promote renewable energies. Moreover, temporary support is granted to existing large-scale hydropower plants due to the financial pressure they are under.

The new Act sets indicative consumption, production and emissions targets. Compared to 2000, energy consumption *per capita* should diminish by 16% in 2020 and 43% in 2035. With regard to electricity, consumption *per capita* should diminish by 3% in 2020 and by 13% in 2035. On the production side, electricity production from renewable energies other than hydropower is projected to rise from 2,830 GWh in 2015 to 4,400 GWh in 2020 and 11,400 GWh in 2035. Hydropower production should diminish slightly, from 39,500 GWh in 2015 to 37,400 GWh in 2035.

The intended increase of electricity production from renewable energies other than hydropower requires state support. In Switzerland, the main instrument for the promotion of electricity production from renewable energy sources is a feed-in tariff (FIT), which was introduced in 2009. The Swiss FIT is available for hydropower with a capacity of up to 10 MW, solar energy, wind energy, geothermal energy as well as energy from biomass and biological waste. It is paid directly to the producers as a fixed remuneration, at a cost that covers the difference between the production cost and the market price. This guarantees the producers of electricity from renewable energies a price that covers their production costs. The FIT is financed through a grid surcharge imposed on electricity consumers. The maximum amount of the grid surcharge is defined in the Energy Act. The Federal Council may define the exact amount of the grid surcharge within this maximum amount. In 2019, the grid surcharge amounted to CHF 2.3 cents/kWh, which is the maximum amount as defined in the Energy Act.

The revision of the Energy Act has also led to amendments of the Swiss FIT system. The FIT will be replaced by feed-in premiums. Eligible producers are required to market their electricity themselves. The difference between the market price and the production costs will still be compensated. However, producers are responsible for selling their electricity directly on the market. It is in their interest to sell their electricity when demand is high, which gives them an incentive to produce electricity when supply is short and prices are high. The feed-in premium system is of limited duration and will only be granted for up to five years after the entry into force of the new Energy Act (i.e. until 2022). The new Energy Act also raises the grid surcharge to CHF 2.3 cents/kWh, which increases the financial resources for the promotion of renewable energies significantly. For electricity consumers, this means an additional financial burden of CHF 40.00 per year based on the consumption of a four-person family household.

For photovoltaic installations, the new Energy Act alternatively provides for an investment aid. The one-time subsidy covers a maximum of 30% of the investment costs of a reference installation. This applies to new hydropower stations with a capacity of more than 10 MW, and significant extensions of existing hydropower stations as well.

Due to the low European wholesale electricity prices and the resulting financial pressure on the existing hydropower plants in Switzerland (as mentioned above), the new Energy Act also provides for support to existing hydropower stations. Existing large-scale hydropower stations (i.e. with a capacity of more than 10 MW) will be able to claim a market premium for electricity, which must be sold for less than the cost of production. The premium is capped to CHF 1.0 cents/kWh and the total available financial resources are limited, as CHF 0.3 cents/kWh of the grid surcharge will be used for this support. This measure is valid for a period of five years (i.e. until 2022).

Judicial decisions, court judgments, results of public enquiries

Costs of system services

In a recent ruling, the Federal Supreme Court stated that power plant operators are not obliged to pay a portion of the costs for the procurement of system services, and declared that the corresponding provision in the Energy Supply Ordinance (SR 734.71) is not applicable. In view of this, in its own ruling dated 4 July 2013, ElCom instructed the Swiss transmission system operator (i.e. Swissgrid) to refund all outstanding payments for system services for 2010 to the power plants involved. In the meantime, all power plants have received a refund of the amounts paid for system services in 2009 and 2010. Some power plant operators also claimed late payment compensation, and ElCom ruled that Swissgrid has to pay them 5% interest with effect from the date of the reminder.

In two other rulings, the Federal Administrative Court stated that the balance groups to which the Gösgen and Leibstadt nuclear power plants are allocated may not be billed for the costs arising in association with the retention of positive tertiary reserve capacity, and it thus repealed the corresponding order issued by ElCom in 2010. As a consequence of this, ElCom reassessed another, similar case. In accordance with another ruling by the Federal Administrative Court, the owners of a cross-border connecting line cannot be billed for costs associated with idle energy. The Court did not rule on the question of whether a sufficient legal basis exists for billing individual system services to parties that are not end consumers.

Ownership unbundling

In January 2015, the majority of the transmission system grid was sold to Swissgrid. Swissgrid has taken over additional transmission system grid facilities as of January 2016. Prior to the transmission network transaction, ElCom had specified the method of valuation of the facilities to be transferred. The associated ruling of September 2012 stipulated that the valuation of the various transmission network components was to be based on the regulatory criteria which are applicable for pricing in the electricity supply legislation. This would have amounted to a value of around CHF 2bn. Various companies lodged appeals against this ruling, so at the end of 2013 the Federal Administrative Court upheld these appeals and referred the matter back to ElCom for reconsideration. At the same time, it specified a variety of criteria regarding the valuation method to be applied.

In August 2013, ElCom also ruled that stub lines (with and without supply character) that are operated at the 220/380 kV level belong to the transmission network and have to be transferred to the ownership of Swissgrid. This ruling has become legally binding. This means that uniform criteria are applicable throughout the country with respect to the allocation of stub lines to the transmission network, which now encompasses all lines and installations at the 220/380 kV level.

Right of appeal by end consumers

Tariff audit proceedings may be opened on the basis of a report, or by ElCom in its capacity as regulator. In two rulings, the Federal Administrative Court found that ElCom was not authorised to rule in a specific case upon petition of end consumers regarding tariffs. While an end consumer is entitled to lodge a complaint with ElCom, it is ElCom that has to open proceedings in its capacity as regulator. As complainant, an end consumer does not have the rights of a party in the proceedings. The Federal Administrative Court subsequently qualified this ruling in a decision in which it noted, somewhat vaguely, that this restrictive description of the authority of ElCom was not binding. Thus the authority of ElCom and the status of end consumers in such proceedings will have to be defined more specifically in future rulings.

Water royalty

In May 2018, the Federal Council submitted its dispatch to the Parliament regarding its proposal on the revision of the Federal Act on the use of hydraulic power. The original proposal of the Federal Council to reduce the maximum amount of the water royalty, and to introduce a more flexible model, did not receive majority backing during the consultation phase. Therefore, the Federal Council proposed to maintain the current system, including the maximum amount of the water royalty. In order to support the hydropower electricity producers, the Federal Council further proposed to exempt new or substantially modified hydropower plants from the water royalty for a period of 10 years. However, parliament rejected the draft legislation and adopted an extension of the current legislation until 2024. In the meantime, drafts of new legislation are to be expected in due course.

Major events or developments

Currently, only industrial consumers with consumption of over 100,000 kWh a year may choose their electricity provider freely. A full liberalisation of the electricity market was planned for January 2018. However, following a public consultation, on 4 May 2016 the Federal Council decided to suspend indefinitely the full liberalisation of the electricity market. The Federal Council indicated that full liberalisation will depend on the following factors:

- conclusion of negotiations regarding an electricity agreement with the EU;
- progress achieved by the Energy Strategy 2050;
- prevailing market conditions; and
- revision of the Federal Electricity Supply Act.

On 16 August 2017, Switzerland and the EU took a step forward in linking the Swiss and European emissions trading system. Both parties agreed to sign a linking agreement, which has already been technically finalised one year ago and was on hold during the implementation of the "Stop Mass Immigration" in Switzerland. The agreement was signed in November 2017, and has to be ratified by the Swiss and European Parliaments. In this regard, the Federal Council submitted its dispatch on the approval of the agreement and the necessary partial revision of the CO_2 Act to the Parliament in December 2017. The draft legislation is still the subject of parliamentary debate. The linkage of both emissions trading systems enables Swiss companies to access a bigger and more liquid market and to benefit from THE same competition conditions. In compliance with the EU, Switzerland will also include emissions generated by aviation in its system upon entry into force of the agreement.

Proposals for changes in laws or regulations

In February 2014, the Swiss Federal Office of Energy ("SFOE") resumed work on revising the Energy Supply Act which was suspended in 2011. The aim of the revision is to coordinate the Energy Supply Act and the Energy Strategy 2050, to close existing gaps in legislation and to examine new regulations for conformity with the changing industry conditions.

The revision may also bring the full liberalisation of the electricity market. Moreover, the Federal Council intends to present a draft gas supply act by the end of 2019 in order to update the existing Federal Act on Pipeline Systems for the Transport of Liquid or Gas Fuel, and to seek compliance with EU standards.

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UAE

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Overview of the current energy mix, and the place in the market of different energy sources

The United Arab Emirates (UAE) is a federation of seven emirates consisting of: Abu Dhabi (the capital), Dubai, Ajman, Fujairah, Ras al Khaimah, Sharjah and Umm Al Quwain. Energy matters are regulated on both a Federal and Emirate level.

The UAE is a leading global oil and gas hub, ranking as seventh in the world for proven reserves in both oil and natural gas, and accounting for over 4% of global oil production; it is therefore no surprise that the UAE's energy mix is heavily reliant on these energy sources. The Emirate of Abu Dhabi is the key player in shaping the UAE's energy strategy, both internally and internationally as a powerful member of OPEC, with the Emirate accounting for around 95% of the UAE's proven oil and gas reserves. Hydrocarbon production remains critical to the UAE's economy, amounting to approximately 20% of all export revenue.

However, despite its impressive natural resources, the UAE is a net importer of natural gas, partly as a result of having to service its hunger for power: the country has one of the highest rates of energy consumption per-capita in the world. The UAE's natural gas reserves are currently estimated at around 6.1 trillion cubic meters, however, due to the fact that this gas contains relatively high levels of sulphur (a potentially dangerous and environmentally unfriendly component), it makes developing and processing of this gas challenging. As a result, about 30% of the UAE's gross production is re-injected into oilfields as part of the Enhanced Oil Recovery techniques.

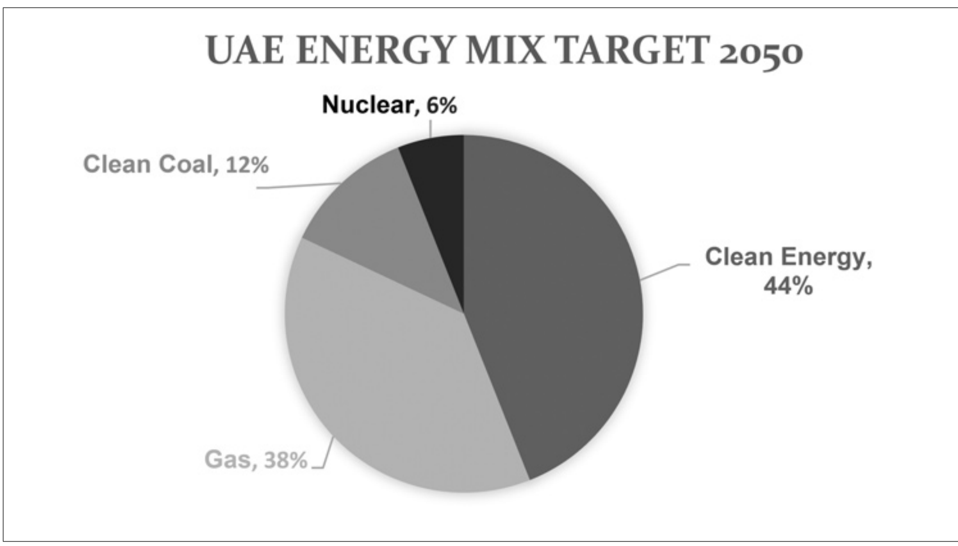
The UAE boasts one of the highest solar exposure rates in the world, but until recently this abundance of renewable and clean energy has not been harnessed on a significant scale as part of the country's energy mix. According to BP's Statistical Review of World Energy 2019, in both 2017 and 2018 renewable energy sources fuelled a mere 0.1% of the UAE's energy consumption needs, with oil and gas fuel sources making up almost 99% of the mix.

The UAE finds itself in a somewhat paradoxical situation where in order to boost investment in renewable energy and other clean energy sources, hydrocarbon development must also be increased to secure government funding.

A combination of the oil price crash during 2014 (which, as with many other Gulf states, had a negative impact on the UAE's economy) and the proliferation of international agreements aimed at reducing reliance on fossil fuels and slowing climate change (principally, the 2016 Paris Agreement on Climate Change and the United Nation's Sustainable Development Goal) has required the UAE to reconsider its energy mix, and its continued reliance on conventional energy sources and power generation methods.

Accordingly, in 2017, the UAE Government launched the "Energy Plan 2050" which aims to dramatically increase the use of "clean" power sources, with the added economic benefit of allowing the UAE to de-risk its exposure to fluctuating carbon-based commodity markets. The Energy Plan 2050 has a number of ambitious goals, with much greater emphasis on renewable, nuclear and clean energy sources. It aims to cut carbon dioxide emissions by 70% and improve energy efficiency by 40%.

The UAE State of Energy Report 2015 reported that the share of power generated from natural gas will drop from 98% in 2012 to less than 76% in 2021, as clean energy enters the energy mix. This target appears ambitious on current figures. The UAE has budgeted up to US$160 billion to meet its growing energy demand and reduce reliance on fossil fuels, with the target of achieving an energy mix of 44% clean energy, 38% gas, 12% clean coal and 6% nuclear by 2050 (illustrated below). On an Emirate level, Dubai is seeking to implement its own "Dubai Integrated Energy Strategy 2030", with far lesser oil and gas resources, in order to achieve an energy mix of 12% from clean coal, 12% from nuclear, 5% from solar facilities and 71% from natural gas by 2030.



Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Oil and Gas

The Abu Dhabi National Oil Company (ADNOC) is currently in the process of implementing a "2030 Strategy", aimed at growing the company (currently the 12th largest oil producer in the world) and its profile across the energy value chain and securing greater market access for its products. A major part of the 2030 Strategy is a shift to growing ADNOC's refining and petrochemical assets to meet growing demand in eastern markets. ADNOC, together with its partners, plans to invest up to US$45 billion by 2030, with the intention to double its refining capability and triple its petrochemical capacity at its existing Ruwais oil hub. This investment would make Ruwais the largest integrated refining and chemical plant in the world as well as cementing ADNOC, and the UAE, as a major downstream player in international markets.

The long-running diplomatic tension between Qatar and the other members of the Gulf Corporation Council (GCC), of which the UAE is a part, which has culminated in an economic blockade of Qatar by its neighbours, has had a negative impact on trade, transport and other sectors in the region. Qatar, through the Dolphin pipeline, provides around 30% of the UAE's energy needs through deliveries of natural gas from its abundant reserves. This supply has continued unabated in spite of the blockade; however, the UAE is all too aware that a reliance on a foreign country, with which it has frosty relations, for its energy security is not a sustainable or secure position to hold.

While not announced as a direct acknowledgment of the UAE's dependence on Qatari gas, the Supreme Petroleum Council (SPC), the body responsible for setting and regulating petroleum-related policies, objectives and activities of the Emirate of Abu Dhabi, publicised a five-year gas strategy, worth US$132 billion, with the target of allowing Abu Dhabi to become a net exporter of gas in five years. The Emirate also wants to increase its oil production to five million barrels per day by 2030, up from current rates of around three million barrels per day. In furtherance of this strategy, ADNOC has granted major oil and gas concessions to Italian oil supermajor Eni to develop the Hail, Ghasha and Dalma ultra-sour gas fields. These fields are estimated to hold trillions of cubic feet of recoverable natural gas, with the expectation that they will be able to supply 1.5 billion cubic feet of gas to the Abu Dhabi market per day.

<u>Renewables</u>

Until recently, electricity produced through renewable technology has not been a competitive or affordable alternative. However, as the UAE seeks to move away from its reliance on hydrocarbons, there has been increased investment in renewable technology, particularly solar photovoltaic (PV) systems. The UAE's location in the world's 'Sun Belt' with extremely high solar irradiation, makes it eminently suitable for various forms of renewable energy technologies, in particular solar PV. Indeed, Business Monitor International's Q1 2019 report states that solar power is the main source of renewable energy in the UAE, with solar generation rising from 1.25 TWh in 2018 to 13.66 TWh in 2028.

In furtherance of the aims set out in the Energy Plan 2050, individual Emirates are setting independent renewable energy targets and starting to implement projects. The renewable energy sector is expected to increase power generation from 0.9% in 2018 to 6.9% in 2028. Certain of the renewables and "clean" energy projects include:

Abu Dhabi

The Abu Dhabi Water and Electricity Authority commissioned Shams 1 (meaning "Sun" in Arabic). This is a solar-thermal plant, which began operation in 2013. It has a capacity of 100 MW, generated by 768 parabolic trough collectors, which generates clean, renewable electricity. The use of Concentrated Solar Power (CSP) allows the plant to dispatch peak power at nights, a first of its kind in the GCC, and one of the largest CSP facilities in the world. Shams 1 generates enough electricity to power 20,000 homes in the UAE and significantly contributes towards Abu Dhabi's target of 7% power-generation capacity via renewable energy.

In January 2019, Noor Abu Dhabi – the world's largest single-site solar project – with a capacity of 1,177 MW and power enough for 90,000 homes, started its commercial operation. The solar plant is located in Sweihan in Abu Dhabi and is a joint venture between the Abu Dhabi Government and a consortium of Japan's Marubeni Corp and China's Jinko Solar Holding.

Most recently, the Emirates Water and Electricity Company announced that work on a 2,000 MW solar PV plant in the Al Dhafra region has commenced. This project is expected to be operational in the first quarter of 2022 and will boost Abu Dhabi's solar capacity to 3,200 MW.

Finally, the Abu Dhabi Department of Energy announced this September that it has signed a Memorandum of Understanding with the State Grid Corporation of China. This strategic partnership will further help the Emirate's ambition to expand on its strategy on clean and renewable energy. This collaboration shows the cooperative approach the Emirate of Abu Dhabi is taking with international investors, particularly with the State Grid Corporation of China, in promoting innovation, technology and efficiency in the renewable energy arena.

Dubai

In Q1 2019, Dubai's Electricity and Water Authority (DEWA) installed and connected approximately 1,276 solar panels on the roofs of residential, commercial and industrial buildings. DEWA has been pro-active on implementing the Energy Plan 2050 by administering the Shams Dubai Program, which allows customers to connect their PV systems to the DEWA grid and offset any excess generation from future electricity bills.

DEWA is itself in the process of implementing several solar projects, most notably the Mohammed bin Rashid Al Maktoum Solar Park, which is the first project such to be implemented in Dubai using the IPP model of securing external investment. Bidders have been invited for the fifth phase, which will be commissioned from Q2 of 2021, reaching a total investment of AED 50 billion (US$ 13.5billion), and a planned capacity of 5,000 MW by 2030. In keeping with Dubai's image as having the "biggest" and "tallest", the project will boast world's tallest solar tower (260 metres) and largest thermal energy storage capacity, allowing constant energy generation. The project also achieved the lowest Levelised Cost of Electricity, of US$2.4 cents/KWh for the 250 MW solar PV panels' technology, and US$7.3 cents/KWh for the 700 MW CSP technology, the lowest globally.

DEWA has also recently invited bids for new floating solar PV plants on a section of the Arabian Gulf. Floating solar farms are growing in popularity and are primarily being targeted by countries where land availability is scarce.

Dubai has also progressed the engineering of a hydro-energy storage in Hatta, after awarding the construction contract to the Strabag Dubai LLC, Strabag AG, Andritz Hydro and Ozkar consortium. The project of AED 1.437 billion is the first of its kind in the region and will generate approximately 250 MW from water movements in the Hatta Dam. Although still at an early stage, it is expected to run for 80 years and to be commissioned by early 2024.

Developments in government policy/strategy/approach

Sharjah and Ras al Khaimah

In June 2018, the Petroleum Council of Sharjah announced its first ever onshore oil and gas licensing round, with the Sharjah National Oil Corporation (SNOC), stating that competitive fiscal terms were designed to attract foreign investment and technology to the Emirate, which is currently heavily reliant upon imported energy sources. In early 2019, SNOC had awarded interest in three onshore concessions to Eni.

At around the same time, Ras al Khaimah's government-owned oil and gas company, RAK Gas, also issued its first ever licensing round, signing Exploration and Production Sharing Agreements with PGNiG of Poland and, again, Eni.

While oil and gas E&P operations have been undertaken in both Emirates in the past, the move to further open up acreage for licensing was an interesting one, aimed at providing some form of energy security and reducing reliance on imports.

Abu Dhabi

Following ADNOC's first ever licensing round which concluded in 2019, the company has confirmed the opening of bids for both conventional and unconventional resources in a second round of bidding for five new oil and gas blocks, with the first award expected in early 2020. The 2019 licensing rounds attracted bids from the biggest players in the industry from India and China, as well as Western energy firms such as OMV, Eni and Occidental. The licensing rounds also saw Eni become the first international oil company to be granted operatorship of an oil or gas blocks (Blocks 1 and 2) in Abu Dhabi.

The Department of Energy and Digital Authority of Abu Dhabi has launched instant trade licensing services as the capital seeks to provide fast and effective services to small-sized energy businesses. Trade licences eligible for such services include, amongst others: water production, treatment and desalination; electricity generation; and wastewater collection. The department is also recommending both strategic and execution plans for the energy sector, specifically those that include oil and gas, water and electricity, sewerage and district cooling, and clean energy sources. This investment in renewable energy is a long-term strategy and although it requires a regulatory framework and governmental backing, the funding will eventually come from hydrocarbons revenues.

In line with the UAE push to expand its energy mix, the State is commissioning the region's first nuclear power plant, the Barakah Nuclear Energy Plant, in Abu Dhabi. Construction of the plant is nearing completion and, once fully operational, it is expected to produce approximately 25% of the UAE's electricity needs. The Barakah Plant is being developed in a joint venture with Korea Electric Power Corporation and at the time of going to press, the third of four nuclear reactors has been energised, with operations slated to commence in early 2020.

Dubai

Dubai has recently installed advanced electric metering systems, which involve using technology in urban planning as part of a "smart cities" approach. These systems operate through structures that encourage customers to reduce consumption or shift it to off-peak hours. Dubai has also introduced a Clean Energy Strategy 2050, with the aim of having clean energy contribute 25% of total energy output by 2030, and 75% by 2050. As part of this, Dubai is developing clean coal projects, and the first phase is expected to begin operating in 2020.

In addition, DEWA announced its strategy in developing "smart grids". In line with DEWA's current drive for innovation in the renewable and clean energy sector, it is working on a futuristic infrastructure that will allow the management of services and facilities through smart systems that use technologies such as AI and blockchain technologies. As in most sectors, DEWA's vision in this field is to become the global leading innovative utility provider. DEWA has budgeted approximately up to Dh7 billion ($1.9 billion) to achieve this 2035 vision.

Developments in legislation or regulation

Foreign Direct Investment

In 2018, the UAE passed the long-awaited Foreign Direct Investment Law (FDI Law), which is intended to pave the way to relaxing foreign ownership restrictions on companies. This was considered one of the major shifts in UAE policies, where previously foreign investors were restricted to a maximum holding of 49% in any venture, excluding free zones.

In July 2019, the UAE Cabinet issued its initial decision on commercial activities across the

13 sectors that will be eligible for "up to 100%" foreign investment, including activities within the renewable energy sector (particularly solar PV projects). Although this announcement does not yet make clear the actual level of foreign ownership authorised that each activity will benefit from, this is a bold step that the UAE Government is taking by moving away from a longstanding position of restricted foreign ownership in order to open the market to greater foreign investment.

This also comes at a time when the UAE is passing laws relating to local substance requirements (on the back of the EU noting the UAE on its tax blacklist for alleged non-compliance with the BEPS regime), enhanced data protection laws, and a "dual licence" regime allowing free zone entities to also work "onshore". This is a very positive direction of travel for the UAE, where the government is focusing on developing the UAE economy and legal framework to become a more transparent, reliable and welcoming jurisdiction for foreign investment.

<u>Regulatory development in the oil & gas sector</u>

In line with the current UAE strategy to encourage foreign investment, the Abu Dhabi Global Market (ADGM) formalised its cooperation with the SPC on the licensing of oil and gas activities. It is now possible for companies that are established in ADGM to apply for oil and gas trade licences, without the need to establish a presence onshore with the Department of Economic Development, although such applications are still subject to SPC approval.

<u>Technology in the renewable energy sector</u>

The UAE is continuing its attempts to attract significant foreign investment across a range of sectors, including the technology sector, with investment into medium- and high-tech projects accounting for over 60% of the total foreign direct investment into Dubai in 2017 (as reported by the Dubai FDI Monitor). Certain free zones in Dubai are focused on promoting renewable technologies and encouraging the development of smart and sustainable cities, including the Zayed Smart City Project and Dubai Silicon Oasis.

Under Dubai's Plan 2021, Dubai is developing a smart and sustainable city, with a particular focus on sectors such as infrastructure, urban planning and electricity, with one of its objectives to optimise its energy sources. Under the same plan, Dubai is working on transforming the way it delivers its services, especially in the utilities and energy sector. In Abu Dhabi, the Zayed Smart City Project encourages sustainability, and reliance on smart technologies in providing services. The UAE's smart cities drive aims to achieve an overarching greater sustainability and efficiency, as it equips the UAE with the means to better face the economic (reliance on hydrocarbon prices) and environmental challenges, through smart infrastructures and smart energy production.

<u>Transport and the renewable sector</u>

Another example evidencing the UAE clean energy approach is the Dubai Autonomous Transportation Strategy, which intends to transform 25% of all transportation to autonomous means by 2030. The Dubai Supreme Council of Energy has launched initiatives to support electric vehicle owners, including free: charging, parking and registration fees. Most recently, DEWA has agreed to sell a considerable amount of its International Renewable Energy Certificates to Unilever in an effort to promote clean energy use in Dubai.

The UAE has only recently become a market for renewable energy. The aim for rapid growth has been accompanied by waves of new legislation on the topic. Whilst there are no specific laws and/or regulations aimed at renewable energy, the diversification and development of renewable energy thus far have been made possible due to the involvement of the Federal and Emirate-level governments. The government's commitment to meet its renewable energy goals, and openness to new investment and technology-transfer opportunities, makes the UAE one of the fastest-growing countries in the region.

A development in the regulatory framework, including a Federal law on renewable energy, will further advance the UAE approach, by attracting more foreign investment. Consequently, the UAE Government is working more closely with businesses to hit clean energy targets. It has been reported that the Federal National Council is in the process of proposing new legislation to regulate clean energies from renewable, zero-emission sources such as solar, wind and hydropower.

Judicial decisions, court judgments, results of public enquiries

The UAE's courts do not systematically publish decisions, making it difficult to ascertain if there have been any developments in their current thinking any given topics. Furthermore, as a civil law jurisdiction, there is no principle of binding precedent in the UAE local courts – judgments and decisions of the courts are merely persuasive on future decisions, and so we are not aware of any major decisions, judgments or enquiry findings by the UAE courts, or regulatory bodies, that directly pertain or affect the energy sector.

Major events or developments

The UAE's reliance on global oil and gas trading, together with its location in the Gulf, means that it is acutely affected by movements in commodity prices. The UAE's involvement in the war in Yemen (seen by many as a proxy war between Iran and the Kingdom of Saudi Arabia, and its allies – including the UAE), together with increased tension between the US, a strategic partner of the UAE, and Iran have resulted in an uptick in violence and instability in the region. Tensions with the seizing of oil tankers, attacks on tankers off the UAE's northern Emirate of Fujairah, cumulating in the huge attack on major oil processing facilities in Saudi Arabia which led to record in-day rises in the prices of crude oil on global markets. The UAE will be affected by increases in oil prices (primarily positively, as a net exporter of crude), but will see more lasting negative consequences, with possible destabilisation in the region, potentially leading to decreases in foreign investment by an escalation of violence in Yemen or any increased tensions between Saudi Arabia, the US and Iran.

Proposals for changes in laws or regulations

While the UAE is seeking to attract foreign investment and technological know-how in the energy sector, the UAE's future energy projects look likely to continue to be government-run, with government authorities or state-owned companies as the major stakeholders. Government involvement in this manner has, in many respects, negated the requirement for all-encompassing legislative and regulatory frameworks governing the various energy sources and new technologies.

The primary goal of the UAE's Federal and Emirate-level government is continuing efforts to encourage private sector participation and investment in clean and traditional energy sectors, whether through new legislation, such as the FDI Law, or changes in the project documents regulating the oil and gas industry (for example, allowing foreign companies to operate oil and gas blocks for the first time).

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Overview of the current energy mix, and the place in the market of different energy sources

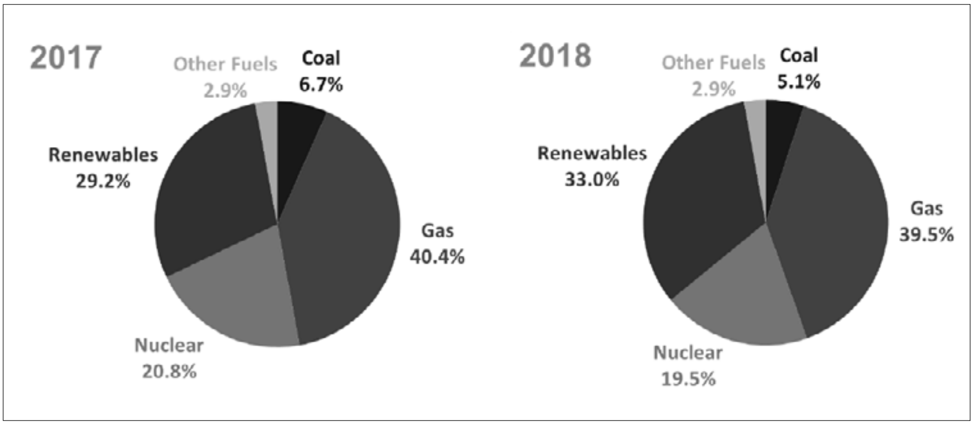
The UK has not experienced any dramatic changes in relation to its energy mix in the last 12 months – rather, it has been a case of continued change at a steady pace. As in previous years, there has been a sustained trend of increased generation from renewable sources, with a marked decline in generation from fossil fuels, with coal in particular being on the way out as a fuel.

Renewable generation increased by 11% in 2018 – this continued increase in renewable generation capacity means that renewable generation in 2018 was 33% higher than in 2016.[1] If broken down further by technology type, renewable energy generation in 2018 was made up of the following: bioenergy (i.e. energy from organic materials, such as biomass) – 31.6%; onshore wind – 27.5%; offshore wind – 24.3%; solar PV – 11.7%; and hydro – 5%.

By contrast, coal's share of generation fell to 5.1% in 2018, down 1.6 percentage points on the previous year.[2] This was a record low, and this decline in coal generation is in line with the UK Government's decision that all unabated coal generation (i.e. coal generation without the means to capture/reduce carbon emissions) must cease by 1 October 2025. Over May/early June 2019, Britain experienced a record 18 days and 6 hours without coal generation, although, during this time, gas accounted for approximately 40% of generation – being a clear indication of the key role that gas generation still plays in the generation mix.

See Figure 1 below for a complete breakdown of sources of electricity generation in the United Kingdom in 2018, as compared to 2017.

Figure 1: Share of electricity generation in 2016 and 2017[3]



There has not been such a significant change in the sources of energy in other sectors, such as transport and domestic heating – for this reason, fossil fuels continue to make up a large percentage of energy consumption overall. More specifically, the main fuels used by final consumers in 2018 were: petroleum products (47.4%); natural gas (29.2%); and electricity (17%); while biofuels made up 4.3% of final consumption.[4]

Indigenous oil and gas production continues to play an important role in meeting the UK's hydrocarbon needs, although, as in previous years, imports make up the shortfall. Indeed, the combined efforts of the Government and industry in recent years to make the most of the UK's remaining oil and gas reserves appear to be paying off: current levels of production from the UK continental shelf (UKCS) are 20% higher than in 2014, and are meeting 59% of the UK's oil and gas demand.[5]

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Shale gas industry: one step forward, one step back?

Given that the UKCS is considered to be a mature basin, and that it is an undisputed fact that production levels can never again reach the peak they reached in 1999 (crude oil production) and 2000 (natural gas production), the UK Government has looked to develop a shale gas industry – both to meet local gas demand (given that gas is considered to be a key source of energy in the short to medium term, and a means of achieving the Government's objectives of reducing carbon emissions) and also to contribute to the economy. However, as reported in previous editions of this publication, the UK shale gas industry has encountered various challenges, notwithstanding Government support. One of the key challenges has been the fact that shale gas is located onshore and therefore is located in close proximity to populated areas, as opposed to the UK's conventional oil and gas industry, the great majority of which is located offshore. This, combined with the fact that shale gas development involves "fracking", has led to widespread public opposition to shale gas.

The Government has taken various steps to overcome these challenges, including streamlining the approvals process for shale gas development, enshrining in legislation various new safety measures to address community concerns, and putting forward proposals for a new "shale gas wealth fund" so that communities may benefit directly from the revenue generated through shale gas development. However, the industry has continued to suffer setbacks.

One area that has caused particular difficulty is that shale gas companies need to obtain planning approval from the local authority before any work can be undertaken. In July 2018 the Government launched consultation proposals, (i) to categorise non-hydraulic fracturing shale gas exploration development as so-called "permitted development", which would not require planning permission; and (ii) to bring shale gas development into the existing Nationally Significant Infrastructure Project (NSIP) regime under the Planning Act 2008, which would mean that the Secretary of State for Business, Energy and Industrial Strategy would have the final say in all planning consent applications for the production phase of major shale gas projects (as opposed to local authorities which, arguably, are more likely to take local concerns into consideration rather than national interests). While the consultations on these proposals closed in October 2018, no Government response has been published as at August 2019. It seems that the Government has reserved any decisions on these controversial matters – not just because it has more pressing matters to deal with, but also because of more recent obstacles that have arisen in the path towards UK shale gas production.

Firstly, in December 2018 an earthquake tremor with a magnitude of 1.5 on the Richter scale was recorded at Cuadrilla's shale gas site near Blackpool, Lancashire. The tremor was categorised as a "red light" event under the traffic light system introduced by the Government to address safety concerns, and it meant that operations at the site were suspended. This followed an earlier smaller tremor at another Cuadrilla site, which also resulted in work being suspended. In July 2019 Cuadrilla announced that it will be conducting further hydraulic fracturing using a new, more viscous fracturing fluid which has been approved by the Environment Agency as non-hazardous to groundwater and which is less likely to cause seismic activity. While this demonstrates a high level of commitment and perseverance by the industry, it is clear that the tremor limits imposed by the UK's traffic light system present a significant barrier to shale gas development. Moreover, the recent tremors have further contributed to public distrust of shale gas development.

In a further complication, in March 2019 the High Court ruled in favour of anti-shale gas campaign group, Talk Fracking, in a case[6] brought by Talk Fracking to challenge the validity of the favourable treatment given to shale gas development in the Government's National Planning Policy Framework (NPPF). The NPPF constitutes guidance issued by the Government to local authorities on planning issues in England. Talk Fracking challenged the inclusion of a statement in the NPPF that local authorities should recognise "the benefits of onshore oil and gas development, including unconventional hydrocarbons, for the security of energy supplies and supporting the transition to a low-carbon economy; and put in place policies to facilitate their exploration and extraction". The legal basis of the challenge was that this statement did not take into account the most recent scientific and technical developments/studies in relation to the environmental impact of shale gas development. As a result of the High Court decision, on 23 May 2019 the Secretary of State for Housing, Communities and Local Government issued a Written Ministerial Statement to remove this statement from the NPPF.

Conventional oil and gas

In contrast to shale gas, it has been "business as usual" for the conventional offshore oil and gas industry in the UK. For a long time now, offshore licensing rounds have been held on an annual basis. Consistently with this approach, the 32nd UK Offshore Licensing Round was launched on 11 July 2019, with a total of 768 blocks or part-blocks on offer across the main producing areas of the UK continental shelf (UKCS). It is possible for blocks also to be offered outside of an official round, although this is not common. In an interesting development, on 1 August 2019, the Oil and Gas Authority (OGA, the oil and gas regulator) launched a restricted "out of round" offer for two blocks around the Northern North Sea Rhum Field.

As mentioned above, production levels in the UKCS have been high compared to previous recent years, and the OGA is optimistic about the remaining reserves: in a recent report, the OGA estimated that "4 billion boe is yet to be discovered from the existing UKCS inventory of mapped prospects, with an additional 11 billion boe possible if exploration is extended to plays".[7] However, one area that the OGA has been less upbeat about is the levels of exploration activity, which have been identified as being "historically low". Therefore the OGA has signalled that increasing exploration activity in the UKCS is an area of focus for the regulator – both by supporting industry (e.g. by making more data available through the new National Data Repository, which was launched in March 2019) and also by enforcing all seismic and drilling obligations that licensees may be required to fulfil under their licence.

Brexit: counting down

Ever since the clock started ticking on the timetable for the UK's exit from the EU (which was originally scheduled for 29 March 2019 but is currently set for 31 October 2019), there has been a great deal of discourse about the impact of Brexit on the energy industry in the UK – and indeed, on security of energy supply. While a detailed discussion of all the possible impacts is outside the scope of this chapter, it has been widely acknowledged that there will be a general, non-direct impact across the whole industry, resulting from issues such as barriers to the sourcing of workers and equipment from the EU, particularly if there is a "no deal" Brexit (i.e. Brexit without a withdrawal agreement with the EU, which would include various longer-term and interim arrangements for the EU/UK relationship).

In terms of a direct impact, this is most relevant to the downstream end of the gas and electricity industry, given that the UK's gas and electricity markets are currently part of the EU's internal energy market and tied to the institutional and regulatory structures that underpin the internal market. The UK Government has been adamant that "the lights will not go out" and the UK will be able to continue to trade across the gas and electricity interconnectors that join the UK to mainland Europe; while the GB energy regulator, Ofgem, has been engaging with interconnector owners/operators to ensure all necessary changes to access rules and certification are in place for a "no deal" Brexit. Importantly, the UK Government has been putting in place a detailed legislative structure to implement any current EU law as UK legislation, and providing for UK institutions to take over any roles currently undertaken by EU institutions, to minimise any regulatory gaps that would otherwise arise upon a "no deal" Brexit.

There have been some concerns about the impact of Brexit on the renewables industry in the UK, given that the framework that underlies Government support for renewables is, at least in part, currently tied to EU legislation (in particular, the EU Renewable Energy Directive). However, the Government has been anxious to confirm its commitment to renewables, and it is hoped that the recent new zero net carbon target (see below) will mean that the UK Government will be true to its word.

Nonetheless, as at August 2019, there is growing concern about the economic impact, in the short-term at least, of a "no deal" Brexit, across all industries in the UK, including energy. Boris Johnson, the new Prime Minister, has been adamant that Brexit must take place on 31 October 2019, "deal or no deal".

The climate of political and regulatory uncertainty has been heightened by the fact that while the next general election is not due until May 2022, there is a possibility of an early general election being triggered if certain events unfold, including Members of Parliament attempting to defeat the Government in a "vote of no confidence". While nothing is certain, there is a possibility that at the next general election, whenever that might take place, the Labour Party could form the government. As discussed in more detail below, the Labour Party has said that a Labour Government will roll out a nationalisation programme that would have very significant impacts on the energy industry.

The Labour Party's nationalisation plans

In its manifesto for the 2017 general election, the Labour Party stated that it would "bring key utilities back into public ownership". The Party has since then developed this policy further, with the publication in May 2019 of "Bringing Energy Home: Labour's proposal for publicly owned energy networks" – the Party's nationalisation blueprint. As mentioned above, while the Labour Party is not currently in government, the possibility of a change in government cannot be ignored.

Currently the UK gas and electricity industry is fully privatised and liberalised. The industry, including the gas and electricity distribution and transmission networks, was privatised through a gradual process in the 1980s and 1990s. While the gas and electricity networks are in private ownership, being natural monopolies, they are heavily regulated under a regime enforced by the regulator, Ofgem. The Labour Party's May 2019 paper outlines plans for nationalising the transmission and distribution networks.

Labour puts forward three main justifications for its radical plans:

- the rising cost of energy, arguing that "achieving the highest possible return on investment does not naturally align with meeting the public interest of an energy system that is green, secure and affordable";
- to facilitate decarbonisation of the energy sector, arguing that "the energy sector is central to the UK's decarbonisation process. Yet energy networks are poorly placed to respond to the task at hand"; and
- to allow for "democratic control of a strategic resource".

Labour proposes that upon nationalisation, a new public ownership structure would be put in place, involving: a National Energy Agency to own and operate the transmission networks; Regional Energy Agencies (REAs) to own the distribution network and, in some instances, Municipal Energy Agencies (MEAs) to operate distribution networks (devolved from the REAs); as well as Local Energy Communities, to develop local renewable energy projects and engage in the operation of microgrids.

If the plans are implemented, Distribution Network Operators (DNOs) will be owned, maintained and run by REAs, which will effectively be public authorities. Where more than one private company currently exists, there will be consolidation of companies into one REA. In certain cases, distribution networks may be run at the country/metropolitan/borough level, with REAs being obliged to devolve ownership and operation of the network to the local authority-led MEA.

Labour's policy paper states that nationalisation would be effected through an Act of Parliament which would transfer ownership of the assets to the newly established bodies. Compensation to existing shareholders would be paid in the form of Government bonds, with the level of compensation being decided by Parliament.

Developments in government policy/strategy/approach

Greater focus on the energy transition

Arguably, one policy area that has received particular attention from the Government in the last 12 months has been in the arena of energy transition. While the UK Government has been incentivising investment in renewables for many years now, as well as setting targets for carbon emission reductions since the enactment of the Climate Change Act 2008, as mentioned above, there has been less focus on decarbonising other sectors, such as transport and heat. National and international discourse on the imperative for an energy transition has led to a new focus on creating a more holistic policy framework for the energy transition in the UK, which is underpinned by a new net zero carbon target to be achieved by 2050 (see below).

Some of the concrete steps being taken by the Government are discussed in more detail below, although there is also some concern from industry that not all recent policy and regulatory developments are consistent – for example, as mentioned below, changes being brought about by Ofgem's network charging review; and the withdrawal of support for established renewable energy technologies such as solar PV and onshore wind.

Ofgem's network charging review

In recent years the regulator, Ofgem, has been reviewing the existing approach to network charging. The raft of changes being proposed has been spearheaded by the rise in the number of generators connected to the distribution network (often referred to as embedded generators). This rise in numbers has led the industry and the regulator Ofgem to closely examine the so-called "embedded benefits" (i.e. network costs that can be avoided by embedded generators) to ensure that embedded generators are not being given an unjustified advantage, which could lead to market distortions. However, this has led to a much broader review of network costs, with Ofgem also undertaking a general review of how the costs of using the electricity transmission network (and, to a slightly lesser extent, the distribution network) are recovered from its users.

There are two key workstreams that have formed part of Ofgem's review – the so-called embedded benefits review (which has already been implemented, through a phased approach), and the Targeted Charging Review Significant Code Review (on which Ofgem is yet to reach a final decision). More recently, Ofgem has also launched a Significant Code Review of network access and forward-looking charging arrangements, as well as a review of balancing services charges, which is being carried out by the Balancing Services Charges Task Force led by the System Operator.

In November 2018 Ofgem published for consultation its "minded to" decision on the outcome of its Targeted Charging Review Significant Code Review (the TCR consultation). It is relevant to note that transmission network charges comprise:

- Transmission Network Use of System (TNUoS) charges, which recover the cost of providing and maintaining transmission network assets; and
- Balancing Services Use of System (BSUoS) charges, which recover the cost of system operation.

Both TNUoS and BSUoS are levied partly on generation and partly on demand (i.e. suppliers).

TNUoS charges have two elements – forward-looking and residual. Forward-looking charges are designed to ensure that network users receive signals that reflect the costs of how and when they use electricity, which can encourage users to be flexible in their use, in order to reduce costs. Residual charges, on the other hand, are designed to ensure that network costs not recovered from the forward-looking charges are fully recovered. The same principles also apply to the use of system charges that apply to the distribution network.

Ofgem notes in its consultation that unlike forward-looking charges, residual charges are not intended to send signals or provide incentives to use networks in any particular way. The changes being proposed in the consultation have their foundation in the belief by Ofgem and some industry participants that the existing GB charging arrangements provide opportunities for some users to more easily avoid paying residual charges, and therefore increase the costs borne by others.

Ofgem has also looked at BSUoS charges, because most small (less than 100MW) generators connected to the distribution network do not pay BSUoS, in contrast with larger DG and transmission-connected generation.

Therefore, the focus of the TCR has been on how the residual element of TNUoS charges is applied to users of the transmission and distribution networks, including storage, as well as some of the other embedded benefits (such as those relating to BSUoS charges) which remain after the earlier removal of certain embedded benefits.

Network use of system residual charges are recovered from smaller users, such as households and small businesses, via per-unit consumption charges, and for larger users by a mix of per-unit consumption charges for distribution and peak demand charges for transmission, determined through a mechanism known as "Triad". The Triad system measures the consumption of electricity at three peak half-hour periods of use that are not disclosed to network users beforehand within a wider peak period. Ofgem considers that this approach strongly incentivises users to reduce their consumption of electricity from the networks in anticipation of these periods, and to use on-site generation and storage instead – this shifts residual charges to other users, resulting in an unfair outcome.

Having considered various possible approaches, including a new way of applying the residual charge to generators, Ofgem has reached the conclusion that residual charges should be levied on final-demand users only. This is a change from the current arrangements where residual charges are levied on demand users, some generators (transmission-connected generators, larger embedded generators and extra high-voltage, distribution-connected generators) and storage facilities.

The second part of the TCR has assessed the non-locational embedded benefits which were not covered in Ofgem's 2017 decision to cut embedded benefits. In simple terms, non-locational embedded benefits are the different charging arrangements for smaller embedded generators versus larger generators. For example, smaller embedded generators can get paid for helping suppliers reduce their contribution to the costs of balancing the system. Suppliers pass on most of these savings to smaller embedded generators through contractual arrangements and then recover the cost of these payments from other customers. Ofgem considers that this benefit should be removed. Ofgem expects to make a final decision on the TCR review by the end of 2019.

The change in approach will have an impact on all users of the system, including all generators, and generators connected to the distribution system, in particular. A big proportion of the generators connected to the distribution system (as opposed to the higher-voltage transmission system) are renewable energy generators, and therefore the loss of some of the benefits currently available to them through the network charging regime is seen by the industry as a setback, at odds with the Government's low carbon strategy.

There are also other ways in which the proposed changes are expected to have a more adverse impact on renewable energy generators as compared to conventional generators – for example, proposed changes to balancing charges. There is some concern from industry and commentators that insufficient consideration has been given to the impact of the changes to network charging on renewables, particularly when the changes are considered in the context of the overall market structure. For instance, Aurora Energy Research has noted that the changes will "benefit thermal generation at the expense of renewables and battery storage as these assets are unable to capitalise on higher capacity market payments due to their low contribution towards security of supply", and that "consequently, the TCR could hinder the growth of subsidy-free renewables and undermine GB's decarbonisation targets".[8]

<u>An energy white paper?</u>

At the end of 2018, the Government announced that in 2019 it would be publishing an energy white paper. In the UK, a white paper is a policy document produced by the Government to set out proposals for future legislation and, in practice, signals a raft of changes and/or a significant departure from current policy direction. The last energy white paper was published over a decade ago, in 2007, and at that time it was prompted by a perceived need to address the so-called "energy trilemma" – that is, the need to reduce carbon emissions, while at the same time addressing energy security and affordability. At the time of the 2018 announcement, the Secretary of State said that the need for a white paper was partly prompted by the fact that the cost of renewables had fallen, and that the Government would adopt a "market-led approach" to energy policy. The white paper, due to be published in summer 2019, has been expected to deal with issues such as the future of electricity network operation and regulation, a new Regulatory Asset Base model for new-build nuclear, and perhaps some proposals on low-carbon heat.

As at August 2019, the white paper has not yet been published, but at the end of July the Government released a number of consultations dealing with some of the matters that had been expected to be dealt with in the white paper, the most interesting and significant of which are discussed further below.

Regulated Asset Base (RAB) model for nuclear

As outlined in previous editions of this publication, the UK's policy in recent years has been to support the development of new-build nuclear power projects, as a low-carbon source of electricity to complement renewables. This resulted in a pipeline of projects at different stages of planning and development. However, one difficulty has been the fact that the Government decided to use the new Contracts for Difference (CfD) regime to support new-build nuclear projects, as well as renewables. While for renewables, CfDs have been allocated through competitive auctions, and have recently resulted in low levels of subsidy (see below), CfDs for nuclear were intended to be allocated to projects through an individual negotiation process. Only one nuclear CfD has been signed, for the Hinkley Point C project, and the high price (which ultimately gets passed down to energy consumers) has been widely criticised.

Consequently, the Government has published for consultation proposals for using a Regulated Asset Base (RAB) model for new-build nuclear projects. The RAB model has been used in the UK for monopoly infrastructure assets such as water, gas and electricity networks. Under the RAB model, the asset owner receives a licence from an economic regulator (Ofgem, in the case of gas and electricity transmission/distribution assets), which grants it the right to charge a regulated price to users in exchange for provision of the infrastructure in question. In the case of a nuclear RAB, suppliers would be charged as users of the electricity system and would be able to pass these costs on to their energy consumers. The Government has said that it envisages that in order to attract low-cost capital at the scale required, a nuclear RAB model would have the following key elements:

- a "Government Support Package", to protect investors and consumers against specific remote, low-probability but high-impact risk events, through a set of contractual arrangements;
- a sharing of costs and risks between consumers and investors, established through an "Economic Regulatory Regime" (ERR);
- an economic regulator to operate the ERR; and
- a route for funds to be raised from energy suppliers to support new nuclear projects, with the amount set through the ERR, during both the construction and operational phases (i.e. the revenue stream).

The RAB model would require a new regulator to be appointed, because the existing nuclear regulator, the Office of Nuclear Regulation, is responsible for nuclear safety and security matters.

The fact that cannot be denied is that nuclear energy plants are very expensive to build, and whatever model is chosen, this is an area that will no doubt continue to generate discussion and controversy. The Government appears to acknowledge that no model is ideal, stating in its RAB consultation that the proposals are being presented "on the basis that this model would be introduced alongside our existing model for delivering new nuclear projects, the CfD model, rather than as a replacement. A decision on which model was most appropriate for a particular project would be made on a case-by-case basis".

Carbon capture and storage takes centre stage again

Carbon capture and storage (CCS) is widely recognised as potentially offering a means of achieving decarbonisation at a time when fossil fuels are expected to play an important role in meeting global energy demand. A key point is that the energy transition is just that – a transition from over-reliance on fossil fuels – and therefore an important part of the transition is not just switching to renewables but also dealing with carbon emissions, either by capturing/reducing them (for example, by CCS) or by offsetting them (e.g. by planting more trees).

The fact is, however, that CCS is still very much a nascent technology, and although successive governments in the UK have committed to supporting CCS, and various pilot projects have been launched since 2007, commercial-scale CCS is still not a reality. However, after a period of inaction, the current Government is once again positioning itself to get CCS projects (also referred to as CCUS or carbon capture usage and storage) off the ground.

In November 2018, the Government published a CCS "action plan", which is designed to "enable the development of the first CCUS facility in the UK, commissioning from the mid-2020s". In July 2019, the Government published a consultation on the different business models that could be used to make CCS commercially viable. Until now, the only business model that has been considered was a "full chain" model, where a power project, together with the carbon transport and storage infrastructure, would be supported under a Contract for Difference (the same model that is used for renewable energy projects).

The Government is now considering a new model, where the chain would be split and there would be a new business model for the carbon transport and storage elment – that is, a carbon transport and storage operator would be responsible for developing and managing the transport and storage infrastructure in a specific region, with different users of the infrastructure charged a fee for using such infrastructure. The consultation further notes that the reviews undertaken so far indicate that the RAB model, mentioned above in relation to nuclear power plant projects, may be appropriate in relation to carbon transport and storage infrastructure. Other models are also considered.

Importantly, CCS is being considered not only for power projects, but also as a solution to carbon-emitting industry: the consultation notes that "CCUS is fundamental to the decarbonisation of energy intensive industries (EIIs), such as steel, cement, oil refining and chemicals, some of which lack alternative options for achieving deep decarbonisation". CCUS to support hydrogen production is also considered, although currently the production of hydrogen as a fuel is merely in the planning stages – only a very small amount of hydrogen is currently produced in the UK and this is mainly for the petrochemical industry.

Alonside the consultation on business models for CCS, the Government has also issued a consultation looking at the re-use of oil and gas assets for CCS. There is extensive oil and gas infrastructure in the UKCS – primarily pipelines and platforms – which will no longer be required once the fields they serve rearch the end of production. It has been recognised that in addition to the actual depeleted oil and gas fields, the geological features of which make them ideal for carbon sequestration, some of these assets, instead of being decommissioned, could be re-used for CCS. To facilitate such re-use, the consultation proposes giving the Secretary of State a discretionary power to relieve former oil and gas owners and operators from decommissioning liability under the Petroleum Act 1998 in respect of assets which have been transferred to a CCUS project.

It is to be hoped that after more than a decade of discussion and policy development in relation to CCS, as well as funding for pilot projects, CCS can become a reality in the next few years. In June 2019 the Government made available yet more funding for a number of "demonstration" projects, with Tata Chemicals Europe being the recipient of the largest grant: £4.2 million towards a £17 million project. Tata's project is intended to extract carbon dioxide from flue gases from Tata's 96 MW gas-fired combined heat and power plant, reducing its emissions by 11%, and re-using that carbon dioxide for the production of sodium bicarbonate.

Developments in legislation or regulation

Net zero carbon target

In a major legislative and policy development, the Government has set a target to reduce greenhouse gas emissions by 100% (compared to 1990 levels) in the UK by 2050. Previously the Climate Change Act 2008 set a target of an 80% reduction by 2050, but the Climate Change Act 2008 (2050 Target Amendment) Order 2019, which came into force on 27 June 2019, amended the legislation to impose the new target. The target has been generally accepted as a positive development, although some environmental campaigners have criticised the 2050 deadline, arguing that it should be brought forward. However, as things stand, the general consensus is that the setting of the target is only the first step and some major policy and technological changes are required to make the target a reality. This fact was acknowledged by the Secretary of State for Business, Energy and Industrial Strategy when he introduced the new legislation in Parliament, stating that:

"*In fulfilling the scale of the commitment we are making today, we will need technological and logistical changes in the way we use our land, with more emphasis, for example, on carbon sequestration. We will need to redouble our determination to seize the opportunity to support investment in a range of new technologies, including in areas such as carbon capture, usage and storage, and in hydrogen and bioenergy.*"

As mentioned above, the UK is already making good progress in decarbonising electricity generation. However, it is in other areas, such as transport, that significant changes are required, as so far very little progress has been achieved to decarbonise sectors outside of energy generation. So how will the Government achieve the target it has set? CCS has definitely been identified as playing a key role. Moreover, the Government is also taking steps to decarbonise transport and heat. In the transport sector, electric vehicles are expected to play an important part in reaching the targets set by the Government.

In particular, in its "Road to Zero Strategy", the Government announced the policy that all new cars and vans should be effectively zero-emission by 2040. To help implement this goal, the Government enacted the Automated and Electric Vehicles Act 2018, which gives the Government powers to make secondary legislation to deal with issues raised by electric vehicles (EV) and their impact on the electricity system. Most recently, in July 2019, the Government launched a consultation on using its legislation powers to mandate EV "smart charging", and a further consultation on requiring residential and non-residential buildings to include EV chargepoints. However, it is clear there is a long road ahead before EVs reach numbers that make a real difference to carbon reduction in the transport sector. Currently, so-called "ultra low emission vehicles" represent only about 0.5% of all cars.

There is less certainty about how the heating sector will be decarbonised. As discussed in a paper[1.] published in December 2018, the Government is considering various options, including electric heating, the use of hydrogen or bioenergy, as well as heat networks, which could be fuelled in a number of different ways, including biomass or using heat pumps. What is clear is that decarbonising heat in the UK is not straightforward, and it is unlikely that there will be a one-size-fits-all solution.

Whatever options are considered, the inescapable fact is that, in the short to medium-term at least, the process of decarbonisation will mean an increased cost to the public – whether through increased costs of electricity supply, the need to install new heating equipment, or otherwise. And, as recent years have shown, increased costs can be a "political hot potato" that the Government is keen to drop. Therefore, the new net zero target can only be achieved if the current Government, as well as subsequent Governments, can commit to a stable set of policies that will incentivise private sector investment in zero-carbon or low-carbon solutions across all industry sectors.

A lifeline for small-scale renewables?

As discussed in previous editions of this publication, the Government decided to close the small-scale renewables Feed-in Tariff (FIT) scheme to new projects, from 31 March 2019. The FIT scheme was instrumental in the development of the solar PV industry in the UK. As prices of established renewable technologies, such as solar PV, fell, and with the desire to reduce the costs of renewables that were being passed on to energy consumers, the Government took the view that there was no longer any justification for maintaining the scheme for new entrants.

However, following feedback from industry and other stakeholders, such as community groups, the Government decided to introduce a new scheme for small-scale renewables, referred to as a "Smart Export Guarantee". The Smart Export Guarantee will enable anaerobic digestion, hydro, micro-combined heat and power (with an electrical capacity of 50kW or less), onshore wind, and solar PV generators with up to 5MW capacity to receive payment for exported electricity from electricity suppliers. This may sound similar to the earlier FIT scheme – however, the scheme will be different to the FIT scheme in two key respects:

- the new scheme will not include a generation tariff – the generation tariff, payable under the FIT scheme, rewarded generators for generating renewable energy even if it was not exported to the grid – under the FIT scheme, a separate export tariff was paid for any electricity that was actually exported; and
- under the new scheme, no set tariff is being prescribed – it will be up to suppliers to determine what tariff they would like to offer to generators.

The Government has said that not setting a minimum tariff will "provide space for the small-scale export market to develop". Suppliers will be expected to implement the new scheme by January 2020. While the scheme is being seen by the industry as "better than nothing", and it is hoped that competition between suppliers will result in reasonably attractive tariffs being set, there is disappointment that the Government decided not to set a floor price for the tariff.

Judicial decisions, court judgments, results of public enquiries

The capacity market standstill

A capacity market (CM) was implemented in the UK in 2014, as part of the Electricity Market Reform package (EMR), to address concerns about there being sufficient flexibility to deal with fluctuations in electricity demand and available supply. Under the CM regime, capacity payments are made to the providers of capacity, including both generation and non-generation forms of capacity such as demand side response (DSR), energy storage and interconnectors. Auctions are held four years ahead of delivery, with a subsequent auction held one year ahead. The CM regime was granted state aid approval by the European Commission (EC) on 23 July 2014. However, on 15 November 2018, the CM regime suffered an unexpected blow: the General Court of the Court of Justice of the European Union found in favour of Tempus Energy, against the EC, annulling the EC's earlier state aid approval for the CM (the Tempus Decision).[2.]

Tempus Energy, a provider of DSR services, was successful in overturning the CM's state aid clearance by arguing that, in granting the CM state aid clearance, the EC should have found that sufficient doubt was raised as to compatibility of the CM with the internal market to invoke the formal investigation procedure provided for pursuant to Article 108(2) of the Treaty on the Functioning of the European Union.

Because the state aid approval of the CM scheme has been invalidated pursuant to the Tempus Decision, the CM was immediately suspended on 15 November 2018. Until the CM can be fully reinstated, the CM is said to be subject to a "standstill" and this period of time is referred to as the "standstill period".

The UK Government has been cooperating with the EC to achieve a reinstatement of state aid of the CM "as soon as possible". The EC opened an in-depth investigation into whether the CM is compatible with EU state aid rules on 21 February 2019, but the outcome of that investigation is not expected any earlier than October 2019, and until there is a positive outcome of the investigation, the standstill cannot be lifted. In a separate development, in January 2019 the EC lodged an appeal against the Tempus Decision and the UK Government is supporting this appeal. In a further complication, in March 2019 Tempus Energy launched a further legal action relating to the CM – this time, a judicial review claim against the Government, challenging the Government's ability to introduce interim arrangements for the CM during the standstill period, including a replacement T-1 auction and arrangements for deferred capacity payments (which are further discussed below).

The Tempus Decision comes at a time when a large number of capacity providers are already receiving capacity payments pursuant to capacity agreements, there are various projects currently being developed that hold capacity agreements, and electricity suppliers are making payments pursuant to the statutory scheme to fund the CM. The standstill therefore has had serious implications for a large number of market participants.

It is relevant to note that, pursuant to the terms of capacity agreements and the statutory framework for the CM regime, there is no mechanism for capacity agreement holders to terminate their capacity agreements on the grounds of the imposition of the standstill. Therefore, capacity providers are expected to continue to fulfil their obligations to provide capacity, in accordance with their capacity agreements, but on the basis that capacity market payments are suspended until such time as the CM is reinstated.

Immediately following the Tempus Decision, the Government directed National Grid to postpone indefinitely the T-1 (one year ahead) and T-4 (four years ahead) auctions, which were previously planned to be held in January 2019, and requested the Electricity Settlement Company (ESC) to stop the making of capacity payments under existing agreements and (on the basis that there was not an immediate need to fund payments to capacity providers) to stop the collection of charges from suppliers. The Government also decided to make some changes to the CM regime (following a public consultation on the issues) to apply during the standstill period, to deal with arrangements applying to existing capacity agreements, as well as modified arrangements to procure capacity by a replacement auction. These arrangements are discussed in more detail below. Independently of the impact of the Tempus Decision, the Government also conducted a five-year review of the CM (as required to by the CM regime), which has also led the Government to introduce some changes to the CM regime.

A replacement "top-up" T-1 auction commenced on 11 June 2019 to procure capacity for the delivery year 2019/20. The making of any payments pursuant to capacity agreements secured through this auction will be conditional on the timing and outcome of the EC's formal investigation. In the event that state aid approval has not been met by the start of the 2019/20 delivery year, the capacity providers who have been awarded capacity agreements will be expected to provide capacity on the basis that back payments will be made to them once state aid approval is received after the start of the delivery year. The Government intends to proceed with changes to allow a T-3 (three-years-ahead) auction to be held for delivery year 2022/23. This is intended to replace the T-4 (four-years-ahead) auction which was postponed because of the Tempus Decision. This T-3 auction is scheduled to take place in early 2020, with the T-1 auction for 2020/21 and the T-4 auction for 2023/24 to take place shortly after that.

The Government's view has been that existing capacity agreements should continue to be administered and enforced during the standstill period to help ensure security of supply and to put capacity providers in a position to be eligible for deferred payments (subject to state aid approval). However, the Government has also recognised that, in light of the uncertainty created by the judgment and standstill period, capacity providers (new-build projects in particular) may find it difficult to achieve compliance with these obligations by the set deadline in some instances. Therefore, the Government decided to modify certain obligations for capacity providers during the standstill period: in some instances, by extending the time for capacity providers to meet certain milestones that fall during the standstill period; and in other instances, by waiving certain obligations that arise during the standstill period.

While it is hoped that the state aid position of the CM will be resolved as soon as possible, there are no guarantees about whether and when this will happen. Another issue to consider is the potential impact of Brexit. While currently the position is far from clear, in a "no deal" Brexit scenario, the UK will no longer be bound by the EU state aid regime. If the terms of the Withdrawal Agreement are agreed as intended, then the EU state aid regime will apply during the implementation period, to be subsequently replaced with a domestic state aid regime which will be enforced by the Competition and Markets Authority.

CM five-year review

It should also be mentioned in this context that, notwithstanding the CM standstill, the Government has undertaken a five-year review of the CM (it being five years since the CM was first introduced), as it is required to do so under the CM statutory regime. One particularly significant decision arising from the review is the fact that going forward, renewable energy projects will be able to participate in the CM. However, such projects will be significantly "derated" for the purposes of the regime, to reflect the intermittent nature of technologies such as solar PV and wind. The Government is also taking steps to implement new carbon emission limits for generating plant participating in the CM, as mandated by the EU's Clean Energy Package.

Major events or developments

<u>Support for renewables: the third CfD allocation round</u>

In recent years, the Contracts for Difference (CfD) regime has been the main mechanism for incentivising investment in renewables. While there is a gradual move towards subsidy-free renewables, particularly that technologies such as onshore wind and solar PV are no longer eligible to apply for support, the CfD mechanism still plays a key role. Since the CfD regime was implemented in 2014, there have been only two allocation rounds, although originally they were intended to take place annually. The long-awaited third CfD allocation round (CfD AR3) was launched on 1 May 2019 and, as at August 2019, it is under way.

The Government is making available £65 million (at 2011/12 prices) in CfD AR3. This budget will be made available to eligible projects with delivery years of 2023/24 and 2024/25. This is a much smaller budget than that offered in the second allocation round, which was £295 million. Moreover, as discussed in more detail below, the Government has indicated that it expects the subsidy levels resulting from CfD AR3 to be even lower than those awarded in the second allocation round.

What is interesting is that, for the first time, a capacity cap is being imposed as well as a budgetary cap. The cap that the Government has decided to apply is 6GW. This means that even if the full budget of £65 million is not spent, the total capacity of all the projects awarded CfDs in CfD AR3 cannot exceed 6GW. It is to be assumed that the capacity cap is being imposed to allow less than £65 million to be spent if the target capacity is procured at sufficiently low strike prices.

Once again, only "less established technologies" are eligible to compete. However, onshore "remote island wind" (RIW) has been added to the less established category – this refers to onshore wind projects on remote Scottish islands. Therefore, the technologies that are eligible to compete for CfDs in CfD AR3 are: offshore wind; RIW; Advanced Conversion Technologies (ACT) (with or without CHP); anaerobic digestion (AD) (with or without CHP); dedicated biomass with CHP; and wave, tidal stream and geothermal technologies.

The budget notice also set out the administrative strike prices (which represent a cap on the strike price that may be awarded to a project) that apply to the difference technologies in CfD AR3, as set out in Figure 2. The "methodology" published by BEIS in December 2018, setting out how the prices were set, states that for CfD AR3, the Government has set administrative strike prices at a level whereby projects representing the 25% of the lowest-cost capacity of each eligible technology should be able to participate in the round.

What is particularly notable is the low administrative strike prices set for offshore wind, which, probably not surprisingly, have been set at a level below the strike prices awarded to two of the three offshore wind projects that were successful in the second allocation round. There is a very clear expectation that the cost of delivering offshore wind projects should be reduced further. In January 2019, the Secretary of State stated that "the cost of renewable technologies such as offshore wind has fallen dramatically, to the point where they now require very little public subsidy and will soon require none". It has been reported that on the basis of the Government's own modelling of the future reference price, as setout the draft Allocation Framework for CfD AR3, for offshore wind projects commissioning in 2024/25 the level of subsidy may be as low as £2/MWh.

Figure 2: CfD Administrative Strike Prices for CfD AR3 (£/MWh, in 2012 prices)

TECHNOLOGY TYPE	2023/24 STRIKE PRICES	2024/25 STRIKE PRICES
ACT	113	111
AD (>5MW)	122	121
Dedicated Biomass with CHP	121	127
Geothermal	129	127
Offshore Wind	56	53
Remote Island Wind (>5MW)	82	82
Tidal Stream	225	217
Wave	281	268

At the time of writing (August 2019), legal action has been commenced against the UK Government in relation to CfD AR3. The legal action has been commenced by Banks Renewables, a renewable energy company, which has applied for a judicial review of the Government's decision to exclude onshore wind and other established technologies from CfD AR3.

Proposals for changes in laws or regulations

No significant changes other than the ones already discussed above.

* * *

Endnotes

1. BEIS, "Digest of United Kingdom Energy Statistics (DUKES)", July 2019.
2. *Ibid*.
3. *Ibid*.
4. *Ibid*.
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6. *Claire Stephenson v Secretary of State for Housing and Communities and Local Government* [2019] EWHC 519 (Admin).
7. OGA, "OGA Corporate Plan 2019 – 2024", 25 April 2019.
8. Aurora Energy Research, "Reforms to network charges: The Targeted Charging Review and its implications", May 2019.
9. BEIS, "Clean Growth – Transforming Heating – Overview of Current Evidence", December 2018.
10. Case T 793/14, *Tempus Energy Ltd and Tempus Energy Technology Ltd v European Commission*, 15 November 2018.

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Overview of the current energy mix, and the place in the market of different energy sources

U.S. energy consumption was 101 quadrillion British thermal units (Quads) in 2018, up from 97 Quads in 2017, according to the U.S. Energy Information Administration (EIA). Within that figure, the mix of sources and uses has been an active topic this year – in legislative chambers, along regulatory agency hallways, and on Presidential candidate debate stages.

Roaring renewables and the keys to further expansion

Renewable consumption was at record levels in 2018, constituting 11% of total U.S. energy consumption, up 3% from 2017. The increase was mainly driven by wind (up 8%) and solar (up 22%). Biomass consumption, including ethanol and biodiesel, was up slightly from 2017 levels, while hydroelectricity consumption was down. In April 2019, renewables reached a milestone by generating more electricity than coal for the first time in history.

Ambitious government carbon-free emissions goals, as well as clean energy policies adopted by large companies and utilities, continued to advance renewable projects. As of July 2019, eight states plus Puerto Rico and the District of Columbia had 100% renewable energy goals or mandates, in addition to 144 cities and counties. Advances in battery storage technology and economics are driving renewables in the direction of the continuous output required for baseload generation.

Large energy consumers are finding creative ways to support renewable projects. Virtual power purchase agreements (VPPAs) do not require the consumer to be connected to the generator; they offer greater price stability for the purchaser and a bankable offtake commitment for the project developer. However, key federal production tax credits for renewable projects face expiration in 2020, which would increase the cost of development capital and test the appetite for investment from other sources. The next generation of renewable projects, some in locations remote from customer bases, will also need to surmount transmission and land use constraints.

Natural gas – A bridge or a pariah?

The U.S. produced 91 billion cubic feet per day (bcf/d) of natural gas in 2018, up 7 bcf/d from 2017. That represents approximately 31% of primary energy sources. Much of this increase is associated with oil production in the Permian Basin of Texas and New Mexico.

Gas inventories have built up and the need for storage, transport and terminaling capacity continues apace. The U.S. became a net gas exporter in 2017 and that status will continue into 2020. In addition to cross-border pipelines, the U.S. Department of Energy (DOE) and the U.S. Federal Energy Regulatory Commission (FERC) have granted approvals for the construction on the U.S. Gulf Coast of a large number of export liquefaction facilities. Domestic liquefied natural gas (LNG) export capacity will nearly double in 2019, from 3.6 to 7 bcf/d.

The U.S.-China trade disputes have resulted in many LNG cargoes heading for South Korea and Japan. World gas prices have been lower of late, so there is less of a spread driving the expansion of the trade in the short term.

Gas prices have continued at low historical levels – around US$2.35 per million British thermal units (MMBtu) in 2019. That figure has continued to spur growth in gas use in the electric generation and transportation sectors, displacing coal projects and accelerating the retirement of existing facilities.

Natural gas was once viewed with bipartisan eyes as a desirable baseload energy source – to wean this and other countries from the higher carbon dioxide (CO_2) emissions and costs of coal-fired generation. The term "bridge fuel" was routinely used, but natural gas is now a fiercely contested source. The favourable gas economics likewise compete with renewable generation, and gas is seen by some as another fossil fuel to be stopped in its tracks. California cities have prohibited gas hookups in new residential construction, and the Democratic Presidential candidates propose to eliminate gas as well as more carbon-intensive types of fossil fuel power generation within a matter of one, two or three decades.

Oil production and exploration

Liquid petroleum products continued to be the largest primary energy source in 2018, accounting for 36% of overall consumption, with most being used for transportation. Consumption was at its highest level since 2007, up nearly 500,000 barrels per day (b/d) from 2017, due primarily to increased demand from the industrial sector.

The Permian Basin continues to dominate oil production, accounting for more than 35% of total output in 2018. Although producers in the region have historically faced challenges in transporting crude to market, some of this pressure was relieved in 2019 by two pipeline capacity additions.

Certain federal lands have recently been opened for oil exploration, including the Arctic National Wildlife Refuge (ANWR) in Alaska. By the end of 2019, the U.S. Department of the Interior (DOI) plans to hold lease sales along ANWR's 1.6 million-acre (650,000-hectare) northern coastal plain, which is estimated to hold over 10 billion barrels of crude oil. However, some predict that interest in the lease sales may be lower than anticipated given the high drilling costs and current prices. Legal challenges have delayed seismic testing until at least 2020, increasing uncertainty and risk for potential bidders.

The Trump Administration also sought to open additional offshore tracts to oil exploration and production through a revised five-year outer continental shelf (OCS) leasing program for 2019-2024. The draft plan proposed opening over 90% of the OCS to energy leasing, including in areas that have not been offered for lease in nearly 40 years. However, a federal court ruling in March 2019 struck down the administration's effort to overturn drilling bans in the Arctic and parts of the Atlantic Ocean, resulting in DOI indefinitely delaying issuance of a final plan.

Coal challenges and carbon capture

Coal's share of the energy market declined by 4% in 2018 and is expected to decline an additional 8% in 2019. Much of the reduction in coal output has been due to new gas-fired generation and renewables.

There was an uptick in bankruptcies among coal producers in 2019, with four major companies filing for bankruptcy in the first seven months. As of the beginning of 2019, more than half of the U.S. coal mines operating in 2008 were closed. These closures tracked the decreasing U.S. demand for coal, mitigated by exports. In addition, coal-fired power plants are under significant economic pressure. In 2018, plant owners retired more than 13 gigawatts (GW) of coal-fired generation capacity, which was the second-highest annual closure on record. On average, coal-fired units are being retired earlier and have a larger capacity as compared to units closed in prior years.

Major energy companies as well as entrepreneurial firms are investing in carbon capture, use and storage (CCUS) technology as a way to curb greenhouse gas (GHG) emissions associated with fossil fuels. Possible applications for the CO_2 captured from coal, petroleum and related sources include enhanced oil recovery, carbonated beverages, and growth of algae to produce biofuels and synthetic gasoline.

Nuclear developments

The domestic nuclear power sector continues to experience challenges. While relicensing has extended the lifetime of some facilities, and many are setting records for generation output, some plants are currently undergoing decommissioning. At least a dozen more are expected to be closed and decommissioning initiated within the next few years.

Decommissioning of nuclear power plants is increasingly being shifted to private entities with the requisite expertise, rather than remaining with the traditional plant operators. This structure has been promoted as being more efficient and cost-effective. There are at least six plants slated to use this third-party decommissioning model, pending approval from the U.S. Nuclear Regulatory Commission (NRC). To date, the NRC has been receptive to this approach upon a demonstration that the acquiring company can safely assume and execute the technical and financial obligations of the licensee.

The DOE is also working with the nuclear industry to advance small modular reactor (SMR) technology, which the agency views as a key part of its goal to develop affordable nuclear power options. The Carbon Free Power Project under review by the NRC aims to utilise SMRs to provide power across six western states. Aside from decarbonising energy portfolios, SMRs can ramp production up and down quickly to complement more intermittent renewable energy.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Electricity storage

Perhaps no change in the energy landscape matters more than the prospects for sustainable growth in the deployment of storage resources for electricity. If renewable energy is to serve as a baseload generation source, storage will be needed at a scale far exceeding its current state.

Looking forward, energy storage continues to grow, with major deployments to the grid primarily by utility-scale projects. Over 300 megawatts (MW) of battery storage capacity were added to the grid in 2018, a number that was nearly matched in the first half of 2019 alone. Energy storage continues to be driven by state-level incentives. For example, California established a 2 GW capacity target by 2020, and New York has an even more ambitious target of 3 GW by 2030.

The federal government has also taken steps to integrate energy storage into the market with FERC Order 841 issued in early 2018. This Order required each regional grid operator to submit a plan to integrate storage into the wholesale market. However, FERC found each operator's integration plan lacking, and issued deficiency notices to operators in early 2019. Several states, operators, and industry groups are challenging FERC's authority to issue Order 841.

From a technology standpoint, lithium-ion batteries continue to be the dominant technology for new installations, making up roughly 90% of the battery storage deployed. These assets are incremental to the larger base of pumped-water storage facilities and projects. Despite some pessimism that global production rates will not be able to meet the projected growth in battery demand, the lithium market currently is experiencing a glut in supply. Some experts continue to predict that alternative storage technologies such as flow batteries will be necessary to extend the time scale for storage and put renewable energy on a comparable level to the readily deployable and consistent conventional electricity sources.

Whether or not lithium batteries remain the market standard, most advanced battery technologies are dependent on rare earth minerals, which have been a target in the present U.S.-China trade dispute. Most rare earths are produced in China, and the U.S.'s sole rare earth mine currently relies on China to beneficiate the resource. This reliance on China has spurred the U.S. industry to prioritise autonomy, with a new U.S.-based separation system set to go online in late 2020. In addition, the federal government is calling for more prospecting and mining in the U.S. where rare earths have been detected, including on public lands that are not currently open to minerals extraction leasing.

Developments in government policy and strategy approach

Offshore wind: state initiatives and federal challenges

As states and private industry are increasingly focused on addressing climate change, offshore wind has emerged as a major component of many carbon-free initiatives. Six Northeast U.S. states have announced procurements qualifying for renewable energy credits and various forms of incentives. Current state policy commitments alone will require approximately 600 times more wind capacity than is currently available.

Despite its role as a cornerstone of many state carbon-free targets, the wind industry faces several challenges in 2020, particularly for offshore initiatives. This includes the expiration of federal production tax credits in 2020 that have made planned commercial-scale projects more attractive to large power customers entering into power purchase agreements, and to investors providing construction financing. In addition, the industry will continue to suffer from a lack of certainty surrounding the federal government's policy on tariffs, the absence of a firm leasing schedule for offshore tracts, and the recent decision the U.S. Bureau of Ocean Energy Management (BOEM) to halt offshore wind development on the East Coast pending a cumulative environmental impact review.

In July 2019, a group of U.S.-based wind tower manufacturers petitioned the U.S. Commerce Department and U.S. International Trade Commission (ITC) to impose tariffs against wind tower imports from certain countries, arguing that the foreign subsidised towers pose a threat to domestic manufacturers. A month later, the ITC agreed to continue its investigation into whether tariffs should be imposed after finding evidence indicating that U.S. manufacturers are being harmed. If tariffs are imposed, analysts estimate that the cost for wind projects in the U.S. could increase by as much as 10%.

The federal government has also been non-committal on OCS leasing schedules for wind developments. BOEM has pointed to numerous competing interests on the OCS – such as recreational fishing, vessel traffic, and military mission needs – as necessitating a slow and deliberative process. To that end, BOEM has established several regional task forces to study a host of issues associated with offshore wind developments, but has not released a timetable for leasing. As of June 2019, there were 15 active commercial OCS leases in place for wind developments, all on the East Coast. BOEM anticipates that it will hold its first Pacific OCS wind lease sale off the coast of California in 2020, but it has not provided details of that or any other future potential sale.

In addition to the uncertainty surrounding future lease sales, developers who have secured offshore leases face unpredictability in the permitting process. The U.S.'s first large-scale offshore wind project was expected to begin construction at the end of 2019. However, in August 2019, BOEM ordered a new environmental review to study the cumulative impacts of several proposed offshore wind projects along the East Coast before allowing construction to proceed. This delay has caused concern within the industry about the federal government's commitment to renewable projects that may be viewed as competing with fossil fuels, and the feasibility of developing large-scale offshore wind facilities in the face of fluctuating requirements.

Vehicle efficiency and fuels standards

Vehicle efficiency standards in the U.S. were a major focus of activity in 2018 and 2019, with the Trump Administration announcing new rules to roll back Obama Administration regulations that required a 54.5 mile-per-gallon (mpg) fuel economy standard by 2025.

In response to the proposed rules, California announced pursuit of its own fuel efficiency regulations, and 13 other states agreed to follow. In July 2019, four major automakers announced a deal voluntarily to increase average fuel efficiency in cars and trucks to more than 50 mpg by 2026, in effect by-passing the Trump Administration's plan to freeze the standards at 2020 levels. Analysts observed that having one national standard was a very attractive prospect for the companies, which is what they were able to achieve through a deal with California. In addition, from a global perspective, many countries are pledging to reduce use of fossil-fuel vehicles in the coming decades. The Trump Administration is contesting the authority for California's arrangement with the automakers on a number of fronts.

The Trump Administration has also drawn criticism from the ethanol industry due to a large increase in exemptions that the U.S. Environmental Protection Agency (EPA) has granted to small refiners under the Renewable Fuel Standard (RFS). The RFS requires refiners to blend a percentage of ethanol into gasoline, but EPA can waive the requirement for small refineries that show financial hardship. In August 2019, EPA granted ethanol waivers to 31 refineries, which was more than four times the 2015 level. The ethanol industry has argued that exemptions issued during the Trump Administration have quadrupled, resulting in over 2 billion gallons of ethanol not being produced and several plants being mothballed.

Developments in legislation or regulation

EPA rulemaking and reversals

In June 2019, the EPA issued the final Affordable Clean Energy (ACE) rule, which replaced the Obama Administration's Clean Power Plan aimed at curbing CO_2 emissions from existing power plants. Dozens of states, cities, public health groups, and nongovernmental organisations (NGOs) have filed lawsuits to block the ACE, arguing that it fails to comply with EPA's obligations to regulate GHG emissions under the Clean Air Act. EPA has asked the court to expedite review of the consolidated actions in the hopes of receiving a favourable ruling before the 2020 Presidential election.

EPA also continued its efforts to roll back Obama-era methane rules that impacted oil and gas operations. In August 2019, EPA proposed a rule that would eliminate federal requirements for oil and gas operations to install technology to fix and detect methane leaks from wells, pipelines, and storage facilities. The rule is expected to be finalised in early 2020 following the public comment period.

Finally, EPA's coal ash rules remain in limbo, after having been found to be lacking by a court in 2018. Coal ash is one of the country's largest waste streams, and while it is officially classified as non-hazardous, it contains lead and arsenic concentrations that have leached from storage ponds and landfills. In August 2019, EPA published a proposed rule dealing with the use of coal ash as fill and with management of temporary coal ash piles. The rule package is the first of three expected revisions aimed at addressing the coal ash regulation deficiencies identified in the 2018 court ruling. Environmental groups criticised the proposed rule as further relaxing regulations surrounding coal ash, rather than strengthening protections.

<u>The new contests over endangered and threatened species protections</u>

In September 2019, the U.S. Fish and Wildlife Service (FWS) and U.S. National Marine Fisheries Service (NMFS) revised the Endangered Species Act (ESA) regulations. The revised rules are designed to accelerate agency determinations for listing and delisting of endangered or threatened species and allow the government to take economic impacts into consideration when making listing decisions or designating critical habitat. Importantly, the revised rules redefine "foreseeable future" in a way that will likely foreclose future listing or designation on the basis of climate change impacts, and eliminate automatic protections to species listed as threatened, as opposed to endangered.

These rule revisions come at a time when the government, NGOs, and the oil and gas industry are gearing up for litigation over protections for the dunes sagebrush lizard, which has habitat in some of the most productive parts of the Permian Basin. Listing the lizard as threatened or endangered under the ESA would limit oil and gas development in the area. Last year, NGOs petitioned the FWS to list the lizard as a threatened or endangered species and to designate critical habitat; the FWS declined. The groups are likely to challenge FWS's decision in court by the end of 2019.

In July 2019, a federal appeals court rejected the FWS's second attempt at a biological opinion and incidental take statement for the stalled Atlantic Coast pipeline project. In its opinion, the court rebuked the agency for failing to fulfil its responsibilities under the ESA to conduct a thorough and scientifically-sound review of the project's impacts on endangered species. A similar strategy is being pursued by several NGOs hoping to halt the Mountain Valley Pipeline project by arguing that the biological opinion issued by FWS failed to properly consider the project's impact on three endangered species. In August 2019, Mountain Valley developers announced that they would voluntarily stop construction activities that could impact the species, pending further FWS review.

Judicial decisions, court judgments, and results of public enquiries

<u>Climate change litigation</u>

Climate change lawsuits continued to press forward in numerous jurisdictions in 2019. As of September 2019, there were seven pending climate cases brought by state and local governments against fossil fuel companies. The cases assert a form of state common law nuisance and seek damages for interference in the use of public or private property. A major battleground in the cases relates to whether jurisdiction over the claims lies in federal or state court, with the governments seeking to keep their cases in state courts and the companies fighting to have the matters heard in federal court. There has been a split in the federal district courts on this issue, resulting in appeals pending in several circuit courts.

The climate change lawsuit brought by 21 young people against the federal government also continued to move forward after the U.S. Supreme Court refused to grant the government's application for a stay in late 2018. The plaintiffs allege that the federal government has violated their constitutional right to a sustainable climate system by allowing fossil fuel companies to operate and by granting leases for minerals extraction on federal lands. In June 2019, the Ninth Circuit heard oral arguments on the government's interlocutory challenges including the question of plaintiffs' standing to bring the case.

Pipeline battles

Numerous oil and gas pipeline projects are the subject of lawsuits brought by various stakeholders – including private landowners, states and NGOs – challenging them on a variety of grounds.

Private landowners in the path of proposed lines are contesting an eminent domain strategy employed by many pipeline developers. Sometimes referred to as "quick take" eminent domain, federal courts have been allowing developers to seize private land immediately after FERC approval of the project, with compensation to be paid later – sometimes months or years later. Landowners challenge this practice, arguing that it exceeds the powers Congress granted to pipeline companies under the Natural Gas Act (NGA). In August 2019, a private landowner challenging use of this practice along the Mountain Valley Pipeline sought review by the U.S. Supreme Court. Although the Court has declined to hear similar "quick take" pipeline cases in the past, recent precedent on property takings without payment may place the present case in a different light.

Although private landowner challenges to the use of eminent domain under the NGA have so far not been successful, pipeline companies' power to seize state-owned property was rejected in a circuit court ruling in September 2019. The court found that the NGA does not give pipeline developers the right to condemn state-owned property, and the court expressed scepticism about whether the federal government could ever delegate this authority to a private party. If the ruling stands, it could effectively give states veto power over pipeline projects if developers cannot find alternative routes that do not involve crossing state-owned land. Analysts have observed that if national energy projects begin to get derailed by states, Congress will likely need to amend the NGA to provide direct eminent domain authority to FERC.

In August 2019, EPA proposed a regulation to curtail the states' ability to delay energy infrastructure projects under Section 401 of the Clean Water Act. Known as a Section 401 certification, the federal statute gives states the right to certify that projects comply with state water quality standards. Industry had expressed concern that states were using the Section 401 certification process to unreasonably delay and increase the cost of energy projects. If finalised, the new rule will prevent states from considering issues other than water quality in their certifications, and clarify that a state's one-year time limit for making its certification decision begins running when it has received a certification request, rather than a complete application.

In June 2019, NGOs received a favourable ruling from a circuit court, holding that the U.S. Forest Service did not have the authority to permit the Atlantic Coast Pipeline to cross the Appalachian Trail. Rather, the court found that the permit had to be approved by the U.S. National Park Service (NPS), which has stricter land conservation rules. The Atlantic Coast developers petitioned the U.S. Supreme Court to review the decision. If the Supreme Court decides to take up the case, its decision is likely to have an impact on the Mountain Valley Pipeline, which is also planned to cross under the Appalachian Trail.

Major events or developments

Wildfires, utilities, and the PG&E bankruptcy

In 2019, the topic of climate change reverberated across the electricity industry with the bankruptcy of Pacific Gas & Electric (PG&E), due in large part to the catastrophic wildfires that decimated several communities in Northern California, resulting in deaths and causing tens of billions of dollars in property damage. More extreme weather conditions are becoming more likely and more severe, and the energy industry as a whole must manage the physical and financial risk of such events.

In the wake of the wildfires, utilities in California and elsewhere are considering mandatory power shutoffs in dangerous weather conditions, boosting vegetation management budgets, and evaluating restructuring, including divestitures to state and local governments. California policymakers are evaluating the state's inverse condemnation precedents, under which a utility may be held strictly liable for the wildfire damages, regardless of the precautions taken.

At the federal level, PG&E's bankruptcy has brought to the fore questions about the relative authority and jurisdiction of FERC and the bankruptcy courts on whether a utility may reject high-cost executory power purchase agreements (PPAs) in a bankruptcy. PG&E management has stated its intent to honour its PPAs, but project owners, especially of legacy renewable energy projects, are remaining vigilant.

Cybersecurity and blockchain in the U.S. energy industry

In the U.S., 90% of energy infrastructure is privately owned, which has resulted in a patchwork of varying information technology systems and security protocols. This leaves the whole energy sector – including the power grid, oil and gas pipelines, refineries, utilities, and governments – increasingly vulnerable to cybersecurity threats. Over one out of every ten electric utilities suffered at least one malware attack in 2019.

The DOE is leading efforts to pinpoint the most dangerous risks and prioritise defences to critical energy infrastructure. Significant gaps in information sharing remain, however, leaving the energy sector susceptible to more attacks. To help close these gaps, FERC strengthened its regulations in 2019 to require grid operators to report all attempts to penetrate systems so that information can be shared across the industry to help prevent future attacks. Additional regulations are being considered to extend mandatory cybersecurity and physical security rules to gas utilities, and legislation is pending to formalise cybersecurity oversight for the pipeline sector.

The advancement of blockchain and distributed ledger technology is also beginning to permeate the energy industry and is being explored by the DOE as a way to make refineries, utilities and the electricity grid less susceptible to cyberattacks. The blockchain applications being developed are aimed at preventing hackers from altering a facility's operational information, thereby thwarting disruptions in service or catastrophic failures. Future applications of blockchain or distributed ledger technologies may help secure energy transactions to protect process data at power plants, increase grid reliability, and create a more decentralised energy infrastructure.

Proposals for changes in laws or regulations

Green New Dealing

2020 is a Presidential election year, and energy and environmental issues are at the heart of the debates. The transformation of Democratic proposals has been rapid and dramatic, spurred by a broad consensus across the party that the global challenge of climate change requires the most urgent national response.

President Obama famously endorsed an "all of the above" strategy in which renewables and energy efficiency joined with U.S. oil and gas production. The fossil fuel aspect of his strategy has been discarded by candidates in favour of sweeping plans to decarbonise the American energy economy.

Democratic members of Congress introduced a non-binding resolution called the Green New Deal, calling not only for eliminating net GHG emissions in 10 years but also for guaranteeing jobs with family-sustaining wages and universal health care, affordable housing, and economic security. The Presidential candidates themselves have separated energy policy from the other goals, but they are no less ambitious on that score – calling for decarbonisation of electricity, or even all energy usage, by deadlines ranging from 2030 to 2050.

The costs of these initiatives are stated to be in the trillions, to be funded by retraction of tax cuts enacted in Republican administrations and large new taxes, including potential carbon pricing. The costs of not responding to climate change are also expressed in the trillions, and the candidates point to the creation of millions of green jobs as a result. Republicans have called attention to the costs and characterised the proposals as tantamount to socialism.

The practical aspects of decarbonisation have been given rather less attention. It is unclear how renewable generation and the associated transportation, distribution, building systems and vehicle infrastructure could replace existing investment in, or close to, the relevant time period. Nor is there clarity on how support for such legislation could be obtained in the U.S. Senate or other forums.

The campaigns will eventually transition from the intra-party primaries to the national stage. It remains to be seen how energy policy will be presented to that more diffuse electorate.

A carbon price by regulatory means?

The New York Independent System Operator (NYISO) is proposing a plan to put a price on CO_2 emissions in the power sector. The plan is intended to complement the climate legislation that was signed into law by New York's governor in July 2019, which requires the state to achieve 100% carbon-free electricity by 2040. Under the plan, the NYISO would attempt to incorporate the social cost of carbon into the wholesale energy markets by assigning a per-ton price for CO_2 emissions. The cost would be factored into electricity generators' offers to sell into the ISO market. Once completed, the plan will be submitted to FERC for approval under Section 205 of the Federal Power Act. Analysts predict that the proposal will raise questions at FERC, including whether an ISO should be allowed to influence public policy in this manner through its tariff.

Another issue that is causing significant debate within FERC and its regulated power markets is how to account for states' out-of-market subsidies. In the wake of the 2018 Calpine decision, in which FERC rejected PJM Interconnection LLC's proposal to change how its auctions are run to account for states' nuclear subsidies, FERC has not offered a fix of its own that grid operators can adopt. In July 2019, FERC ordered PJM to suspend indefinitely a capacity auction that was planned to occur the following month. But the agency still did not offer any specific guidance on rules the operator should apply to future auctions. Pending further guidance from FERC, grid operators are left in an uncertain state. That state of uncertainty characterises much of the U.S. energy landscape for 2020.

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Uzbekistan

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General overview

Along with Kazakhstan and Turkmenistan, Uzbekistan is one of the few countries in Eurasia that is totally energy-independent, self-sustaining and rich enough to subsidise domestic consumption and export energy resources. With abundant gas reserves and a growing gas production rate, Uzbekistan holds the position of the third-largest natural gas producer in Eurasia, behind only Russia and Turkmenistan, and eighth-largest in the world. At the same time, oil production has consistently decreased over the last decade as oil fields are depleted, and this situation puts pressure on the industry to focus primarily on thermal, hydropower and alternative power facilities and capacities.

Limited export capacities, obsolete energy infrastructure and increasing energy demand for the fast-growing population and economy are major concerns for the government, which is now trying to coordinate and implement various programmes to diversify the use of hydrocarbons and their export routes, as well as to encourage renewable energy projects and energy-saving programmes.

Traditionally the energy composition of Uzbekistan has rested upon hydrocarbon consumption, however this year the government made significant steps to incentivise the development of alternative energy sources, including a national programme aimed at increasing energy production and creating a regulatory framework to attract investment to renewable energy projects. More importantly, the government has taken a notable decision to build its first-ever nuclear power plant, which will consist of two VVER-1200 reactors, scheduled for commissioning in 2028 and 2030.

Hydrocarbons, mainly gas, comprise nearly 97% of the country's energy balance, with the remaining 3% coming in the form of hydro, coal and charcoal.[1] Renovating the power transmission networks owned and monopolised by the government is one of the energy sector's priorities. Experts say that Uzbekistan's electricity needs are expected to roughly double by 2030, from 69 terawatt hours to 117 TWh. Without the introduction of new sources of generation, it faces a deficit of about 48 TWh.[2] The government is committed to reducing consumption of natural gas for power generation to free it up for higher-value purposes, including the petrochemicals industry.

Overview of the current energy mix, and the place in the market of different energy sources

Overview of the hydrocarbon industry

In 2018, total crude oil and condensate production in Uzbekistan was about 64,000 barrels per day (bbl/d), while its consumption reached 52,000 bbl/d, as per the *BP Statistical Review* *of World Energy 2019*. It is estimated that nearly two-thirds of all known oil and natural gas fields are located in the Bukhara-Khiva region in the south of Uzbekistan.[3]

According to the *BP Statistical Review of World Energy 2019*, Uzbekistan's proven reserves of natural gas were 1.2 trillion cubic metres (tcm) as of the end of 2018. Uzbekistan produces 56.6 billion cubic metres (bcm) of natural gas annually, with a steady growth rate. The consumption rate of natural gas in Uzbekistan was estimated at 42.6 bcm in 2018. At present, Uzbekistan exports approximately 14.1 bcm of its produced natural gas annually, which breaks down to 5.3 bcm for export to Russia, 2.4 bcm for export to Kazakhstan, 6.3 bcm for export to China and 0.1 bcm for export to Tajikistan.

Uzbekistan serves as a transit country for natural gas flowing from Turkmenistan to China through a strategically important Central Asia-China gas pipeline. This pipeline is also utilised to export natural gas produced in Uzbekistan, and is expected to play a growing role for China. In addition, two new natural gas pipelines, Gazli–Kagan and Gazli–Nukus, were built to connect the Ustyurt and Bukhara-Khiva regions with the existing system.

Overview of the coal industry

Uzbekistan's proven coal reserves were estimated in 2018 at 1,375 million tonnes. The reserves are particularly represented by anthracite and bituminous types of coal, which are widely used in a variety of manufacturing processes, as well as in the production of electricity. The annual production rate, calculated in 2018, is 3.0 million tonnes oil equivalent, and the consumption rate is 3.1 million tonnes oil equivalent, respectively.[4] In recent years, the government has actively developed Shargun field with more than 33 million tons of coal reserves. It is expected that the field's output will increase to 700,000 tons per year in 2019, and to 900,000 tons per year in 2020.[5]

Overview of the nuclear industry

Uzbekistan is a party to the Non-proliferation Treaty and ratified an Additional Protocol Agreement with the IAEA in 1998. Uzbekistan has also ratified the Central Asia Nuclear Weapon Free Zone treaty, and in previous years declared that it had no plan to build a nuclear power station in the country. But to meet the constantly growing energy demand, Uzbekistan, central Asia's most populous country with about 33 million people, made a decision to build the first commercial nuclear reactor with the help of Russia's state nuclear agency, Rosatom. Construction of a nuclear power plant will make Uzbekistan a leading producer of electricity in the region and solve the current problem of stable electricity supply.

According to the 2018 Red Book, Uzbekistan has 57,600 tU in reasonably assured recoverable resources and 81,500 tU inferred recoverable resources to USD130/kg U in sandstone, plus 32,900 tU in black shale. In 2018, the uranium production was about 2,400 tU.

All significant sandstone roll-front-type uranium resources are located in the Central Kyzylkum area, a 125 km-wide belt extending over a distance of about 400 km from Uchkuduk in the northwest, to Nurabad in the southeast. Navoi Mining & Metallurgy Combinat (NMMC), as part of the State Holding Company Kyzylkumredmetzoloto, undertakes all uranium mining in Uzbekistan. NMMC produces 2,400 tU annually, with exports going mainly to the USA through Nukem Inc.; South Korea through Kepco; Japan through Itochu Corp.; and now to China through CGN.

On June 19, 2018 Uzbekistan established the Agency for Development of Nuclear Energy under the Cabinet of Ministers, which will oversee the operations of three corporations engaged for: (1) design and construction of a nuclear power station; (2) operation of a nuclear power station; and (3) development of uranium deposits, marketing and utilisation of uranium.

<u>Overview of the power industry</u>

With the gigantic power-generation facilities of the Soviet era and an ample supply of natural gas, Uzbekistan has become the largest electricity producer in Central Asia. Twelve thermal power plants and 32 hydropower plants annually generate up to 62.4 billion kW/h of electrical power and more than 10 million Gcal of thermal power, of which 88.5% is provided by natural gas-powered thermal plants and 11.5% by hydropower plants. Thermal power plants (TPPs) account for a total capacity of 10.6 million kW; the biggest among them being Talimardjan, Syr-darya, Novo-Angren and Tashkent TPPs, generating over 85% of electric power. For power generation at TPPs, the gas share is 90.8%; mazut is 5.3%; and coal is 3.9%.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

In 2019, the government accelerated economic reforms initiated in 2017 and 2018 to improve internal market and production conditions. Long-expected reforms in the energy sector were the priorities in the government's agenda for 2019.

In February 2019, the President established the ministry of energy responsible for the organisation and regulation of activity of all energy subindustries in Uzbekistan and coordination of both the fuel and energy complex of Uzbekistan. Shortly after, the state made a decision to reorganise the joint stock power company "Uzbekenergo", the historically state-owned monopoly in charge of the energy sector, and joint stock company "Uzbekneftegaz", which controls the oil and gas industry. JSC "Uzbekenergo" was split up into three joint stock companies: JSC "Thermal Power Plants"; JSC "National Electric Grids of Uzbekistan"; and JSC "Regional Electric Grids".

The government recently adopted the Strategy of Nuclear Energy Development in Uzbekistan for the period 2019–2029 and a roadmap for its implementation. The strategy provides for priorities in the nuclear energy industry which include, *inter alia*: the creation and development of the national infrastructure for nuclear energy; environmental protection; and a safe and economically effective nuclear cycle.

International financial institutions such as EBRD, ADB and IFC are actively participating in investment projects related to wind and solar energy. EBRD plans to implement a wind farm with a capacity of up to 1,000 MW, worth US$ 1 billion, while ADB has invested in the project to build a solar PV plant with a capacity of up to 1GW worth US$ 800 million in Surkhandarya and nearby regions. A state programme for the construction of large-scale PV plants was adopted in cooperation with IFC, with a total capacity of 1,000 MW. A pilot project with a total cost of US$ 800 million, for the construction of a 100 MW solar PV station in Navoi region, is being implemented on the basis of a PPP, with the support of IFC.

Investments in the wind energy sector have also been made by Siemens, which is engaged in the construction of a 100 MW wind plant in Navoi region, and by MASDAR which plans to build wind farms in Navoi and Karakalpakstan, worth US$ 500 million. SkyPower Global, Graess Group, Headwall Power, CIRI (Beijing) Information Technology Co., Total-EREN, MASDAR and Mubadala have each entered into framework agreements for the construction of solar power plants with total capacity up to 5,000 MW. In the oil and gas industry, JSC "Uzbekneftegaz", SOCAR (Azerbaijan) and BP (Great Britain) signed a tripartite agreement to assess the exploration potential at three investment blocks of the Samsko-Kosbulak and Baiterek investment blocks of the Ustyurt region, as well as the Uzbek section of the Aral Sea. Other visible players include North Gas Stream, Enter Engineering and Epsilon Development.

Developments in government policy/strategy/approach

Increasing energy sector efficiency and diversifying energy generation are key objectives for the Uzbek government, which has implemented the following policies in the energy sector:

Demonopolisation. The government has decided to reorganise the state-owned vertically integrated power utility responsible for the majority of the country's electricity generation, transmission and distribution and divide into three separate entities: JSC Thermal Power Plants; JSC National Electric Networks of Uzbekistan; and JSC Regional Electric Networks. This is the first step in the creation of a modern wholesale electricity market based on competitive procurement of products.

Establishment of institutional framework. On 1 February 2019, Uzbekistan formed the Ministry of Energy of the Republic of Uzbekistan. The purposes of the newly organised ministry were determined as follows (among others):

- development and implementation of a single state fuel and energy policy;
- regulation of generation, transmission, distribution and consumption of electric and thermal energy, coal, as well as the mining, processing, transportation, distribution, sale and use of oil, gas and products of their processing;
- formation and development of a balanced system of strategic planning and enhancement of the fuel and energy complex;
- increase of the investment attractiveness of the fuel and energy industry, via development of PPP projects, improvement of tariff policy in a manner that would stimulate the formation of a positive competitive environment in the energy market;
- co-ordination of the process of implementation of investment projects in the fuel and energy industry, active attraction of private capital in the field of extraction and production of energy resources;
- building relations with international financial institutions, donor countries, companies, banks and other bodies; and
- assisting in the implementation of modern corporate management techniques.

Renewables: The government of Uzbekistan is aiming to generate approximately 21% of all its energy needs from renewable sources, including solar, by 2031. It is therefore contemplating developing a strategy for the use of alternative sources of energy, along with the very intensive construction of small HPPs in the near future. The government plans to spend 314.1 billion UZS ($81 million) of its own money and raise 20.5 trillion UZS ($5.3 billion) from foreign sources to develop hydro, solar and wind power through 2025. The decree of the President of Uzbekistan adopted in August 2019 defines the measures for increase of energy efficiency, introduction of energy-saving technologies, development of renewable energy sources and the strategy for its implementation. The decree provides for a financing mechanism that allows the government to compensate individuals' expenses for the purchase of PV panels.

Energy efficiency: There are a number of campaigns that are being carried out to install modern meters for consumers of natural gas, hot water and electrical power for households. The efficiency of electricity transmission and distribution is one of the government's priorities, due to significant losses, estimated to represent 20% of net generation, with the cost of excess losses estimated at US$340m.[6]

Added-value: As noted above, the government is also shifting its focus to diversifying the economy by building and operating petrochemical facilities that use natural gas as a raw material to produce petroleum products instead of exporting natural gas. This strategy is confirmed by Uzbekneftegaz top-manager Mr. Sidikov.[7]

Modernisation: The government undertakes to modernise and retool existing outdated, low-efficiency, gas-fired plants, whose efficiency is 40% lower than that of modern thermal plants, as the country loses approximately US$1.2bn in potential gas export revenues.

Gas exports: To increase and diversify gas exports, the Uzbek government plans to increase gas production by attracting foreign investors for the exploration and development of hard-to-recover fields and committing additional volumes for the Central Asia-China Gas Pipeline.[8] In an effort to increase gas exports, the government also plans to use more coal and alternative energy for TPP and domestic consumption.

Increase of production: The government plans to significantly increase the production of oil and gas condensate to keep the country's economy independent of oil imports, which normally come from Kazakhstan. The government is looking to improve the rate of oil recovery, conversion and gas-processing efficiency to raise product quality to world standards, and to increase the acreage for the hydrocarbon resource base, primarily liquids, through new discoveries. The Government has also approved a special five-year state programme on increasing hydrocarbon production for 2017–2021, in line with the Presidential Decree dated 9 March 2017.[9] Specific privileges and preferences are granted to enterprises and organisations that use energy from renewable sources in their production.[10]

Developments in legislation or regulation

In 2019, the government adopted a number of vital documents that map out energy sector development in Uzbekistan for the next decade.

After many years of public discussions, the framework PPP law was adopted in Uzbekistan. The Law "On public-private partnership" was approved by the President of Uzbekistan on 10 May 2019 and entered into force on 12 June 2019. The law defines the general regulation applicable to PPP projects and provides definitions for its key actors (public partner and private partner). A public-private partnership is defined as a "legally arranged cooperation of public partner and private partner for a definite period based on pooling their resources for implementation of a public-private partnership project". This law lays the ground for a regulatory and legal framework which allows foreign and national investors to participate in the development of major energy projects together with the state.

Another notable regulation adopted in 2019 is the law "On renewable energy" that creates favourable conditions, with government incentives for the construction of solar, wind, geothermal and biomass plants as well as hydro plants with capacities of up to 30MW. As per this law, the term "Renewables" includes naturally replenished energy sources, such as sunlight, wind, geothermal heat, natural water waves and biomass. The law "On renewable energy" defines the basis for relationships between the government and the private sector renewable energy producers. The law focuses both on the use of renewable sources of energy and on the production of equipment used in the renewable energy sector.

The abovementioned laws provide for general regulation in the respective fields, and the government further approved a number of roadmaps that define the specific steps to be implemented for the purpose of the enacted laws. Presidential Resolution No.PP-4422 dated 22 August 2019 provides for, *inter alia*, guidance on the implementation of technical measures required by development of the renewable energy sector.

In Presidential Resolution No.PP-4165 dated 7 February 2019, the President approved the Strategy for Development of the Atomic Energy Sector. The strategy describes the goals and directions for the atomic energy sector in Uzbekistan and discusses the steps and measures the government intends to take for that purpose. The document also includes a roadmap for various ministries and state agencies for implementation of the strategy.

Judicial decisions, court judgments, results of public enquiries

Judicial practice is not publicly available in Uzbekistan, and we are not aware of cases where the Uzbek courts have interpreted matters relating to the energy sector. However, we should note that electricity tariffs have been escalating over the last decade, raising concerns on the part of investors regarding increases in production costs. Some foreign investors, whose disputes with the government have been brought before different arbitration forums, intend to file claims for damages relating to the unilateral increase in electricity tariffs.

Major events or developments

In December 2017, Uzbekistan and Russia signed an intergovernmental agreement on cooperation in the use of nuclear energy for peaceful purposes. In March 2018, Uzbekistan shortlisted 10 sites across the country for the construction of a nuclear power plant, and by October the focus was on sites on the eastern and western shores of Lake Tudakul, a reservoir 25km northeast of Bukhara, on the border of the provinces of Navoi and Bukhara. In September 2018, a further intergovernmental agreement was signed for the construction by Rosatom of two VVER-1200 reactors to be commissioned about 2028. The reference units are Novovoronezh II (V-392M).

In May 2019, Rosatom said that a site near Aydarkul Lake in the Jizzakh region had been chosen, near the north-central border with Kazakhstan and north of Samarkand, and that construction was expected to start in 2020 or 2021. In July 2019 it was reported that the proposed site, now for four reactors, would be near Lake Tuzkan, in the Farishsky district. UzAtom's site evaluation is being assisted by the International Atomic Energy Agency (IAEA) as part of its 'Milestones' approach to establish nuclear power. Operation of the two planned reactors is expected to save 3.5 billion cubic metres (126 EJ) of gas per year.[11] The cost is expected to be about $13 billion, largely financed by Russia with participation by the Fund for Reconstruction and Development of Uzbekistan.

Proposals for changes in laws or regulations

There are two important documents expected to be approved before 2020: the Strategy for Development of Renewable Energy Sources for the period 2019–2023; and the Strategy for Fuel and Energy Supply for the period of 2020–2030.

It is also expected that the government will draft new versions of the law "On product sharing agreements", and "On subsoil" before December 2019. These drafts shall set forth transparent mechanisms for tenders and auctions on subsoil use rights, and terms and conditions of the product-sharing agreements with foreign investors, including the requirement to supply oil products to the internal market.

Further, the Government needs to adopt the rules on connection to the grid and the terms for energy sale generated by private power producers. Approval of clear and concise regulation will significantly facilitate the work of project developers and independent investors to plan and finance projects on the basis of well-defined and consistent rules.

Endnotes

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Venezuela

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Overview of the current energy mix, and the place in the market of different energy sources

There have not been significant changes in Venezuela's energy mix throughout the last couple of years. The main energy sources for internal consumption in Venezuela continue to be hydropower and fossil fuels (both gas and liquid fuels, such as gasoline and diesel, excluding coal), with virtually no presence of alternative renewable sources (such as solar energy, wind or bio-fuels). There are a few wind power projects, for example, an Eolic Park in the Paraguaná region called "*Parque Eólico La Guajíra*", but they are mostly stagnant and non-operational (despite recent news that PDVSA is seeking to reactivate the above project in order to supply energy to the CRP refining complex – *Cf*. Argus Media – in practice, they do not go beyond a mere statement of purpose).

As it is well known, for over the last four years there has been a significant decline in power generation in Venezuela, both from fossil fuels and hydropower – which has been attributed by Venezuela's government to different causes, from climate phenomena known as "*El Niño*", to political sabotage, to economic warfare. The ensuing generating crisis was partially averted for most of 2016 through the first half of 2018 due to the shrinking of Venezuela's industrial and commercial marketplace, and most of its basic industries coming close to shut-down (steel and aluminium smelters in Guayana, among others) and electricity rationing in different areas of the country.

The decline in generation can be estimated according to published data at over 20% in just the past two years (according to BP's *Statistical Review of World Energy* 2019, Venezuela's power generation capacity dropped from 117.3 Terawatts per hour at the close of 2017, to just 99.2 Terawatts per hour at the close of 2018; which represents a negative growth of -15.4%). In terms of readiness for installed capacity, as of April this year, barely 6GW of the 34GW of total installed thermal and hydroelectric generation capacity of CORPOELEC, the State power corporation, was operational according to reports leaked out (*Cf*. Argus Media).

Such decline is compounded by an ageing and poorly managed national energy grid which caused mayor blackouts in most large cities in Venezuela during 2018, and which evolved during the first half of 2019 into nationwide blackouts lasting for days (back in February and March this year, as well as more recently in July). Such blackouts impact the marketplace in general, oil production and manufacturing (upgrading and refining), and every activity, including water and telecommunications – telephone and internet – utilities (e.g. national blackout dates and Government decreed nationwide suspension of business and school activities during the first half of 2019 amounted to 23 working days).

More recently, targeted economic sanctions by the U.S. Government against the Maduro regime, and broader sanctions as of August 2019, have hampered and will further adversely affect the Government's ability to pursue the recovery of crippled Venezuela's energy infrastructure.

In any case, at the close of 2018, hydropower remains the main power generation source for Venezuela. According to figures posted by CORPOELEC on its website (http://www.corpoelec.gob.ve/generacion), power generation still results from a mix, 62% of which corresponds to hydropower and the remaining 38% corresponds to thermal generation. While government information and statistics are very limited, experts provide other figures for the mix, in which hydropower generation stands at a higher level, if only because of the rapid decline of thermal generation facilities.

Venezuela's current energy mix is the result of government policies aiming at thermal generation in the light of an ageing hydropower infrastructure and transmission grid, and the inability from 2014 and onwards to carry out the material investment needed to expand, complete, or even maintain the hydropower generation infrastructure (erection of the Tocoma dam, in the lower Caroni, which would add 2,160 MW to the system, has remained stagnant, while the Guri dam has not been performing at full capacity in light of technical limitations, lack of spare parts, and limited manpower, among others). During the past couple of years, CORPOELEC has aimed at updating thermal generation facilities to combined cycle structures (in a scenario where there has been a fall in gas production, as most of the gas produced is associated gas, and hence tied to the shrinking production of oil).

Energy consumption associated with motor vehicles continues to be based exclusively on fossil fuels, and more particularly fuelled by gasoline and diesel, with very little use of gas (the last reports on advances in the completion of gas stations by State-owned *Petroleos de Venezuela*, PDVSA, as covered in its web page, are from 2015 for a total of 342 points country-wide). There is no use of bio-fuel or green fuels.

According to PDVSA's Management Report for FY 2016 (the last management report published by PDVSA to date, as no financials were published for FY 2017 nor 2018), 510 mbpd (refined products and LNG) were sold in the domestic market; no recent figures have been issued by PDVSA or the Government. BP's *Statistical Review of World Energy* 2019 provides a more updated view, identifying figures for internal consumption of gasoline in Venezuela dropping from 716 mbpd in 2008, to about 409 bpd in early 2018. Domestic consumption has continued to shrink and local sources (FENEGAS) identified domestic gasoline consumption to have fallen to an average 200 mbpd throughout 2018, with a further contraction during the first half of 2019 to below 100 mbpd in May 2019.

Reductions in consumption as a result of the ensuing economic crisis and the closure of industries and businesses during 2017 and 2018 allowed the Government to deal with the domestic market issue by restricting supply to border areas and towns (which was then extended at the beginning of 2018 to western border States).

While Venezuela's economy has undergone hyperinflation at rates which for 2018 exceeded two million per cent, no fuel price adjustments have taken place since February 2016 (which had been the first increase in 20 years) and hence, in light of hyperinflation and sharp devaluation, the price of fuel at the gas station is fully subsidised (price equates to roughly US$ 0.0000000001/litre). Notably, in August 2018 the Government announced it would begin increasing gasoline prices one State at the time. The announcement did not go through, except for some western border States where prices have been increased, but remain largely subsidised. The policy first created a significant smuggling market, and price abuses, mostly in border States; more recently the changes have triggered price abuses, shortage of supply and long lines at filling stations.

As of 2019, there are serious gasoline shortages in major cities (commonly Caracas is spared the same), mainly caused by a significant drop in the operations of Venezuela's refining facilities, which are the result of the lack of a stable power supply, chronic mismanagement and lack of proper maintenance. As of May 2019, Amuay is processing about 100,000 bpd and Cardón, Puerto la Cruz and El Palito refineries' operations remain mostly shut down (Cardón and Amuay comprise the CRP refining complex). Experts indicate that most gasoline used for domestic market consumption for the first half of 2019 was imported.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

Venezuela has been in crisis for some time, as evidenced by the economic and political turmoil experienced since early 2016; such situation has only deteriorated throughout 2018 and the first half of 2019, as evidenced by hyperinflation estimated as exceeding two million per cent for 2018 (*Cf.* IMF, Venezuelan National Assembly, among others) and stagnation in the economic arena (more than stagnation, the destruction of the industrial and manufacturing apparatus). Additionally there have been severe political crises, both on the domestic front, with a confrontation between the legislative branch and other branches of Government; the "appointment" of an unconstitutional National Constituent Assembly; the appointment of an interim alternative president and his recognition by more than 60 countries; and the imposition of sanctions by the U.S., Canada and the European Union, on government officials and on certain governmental entities.

In any case, at the end of 2018, proven oil reserves stood at 303,300 mm bbl, according to BP's *Statistical Review of World Energy* 2019. According to the last official data issued by PDVSA on its Management Report for FY 2016, only 13.56% of the proven reserves (40,995 mm bbl) correspond to conventional crude oil (condensates, light, medium and heavy oil) and the remaining 86.43% to extra-heavy crude oil reserves (261,253 mm bbl), most of which is located in the Orinoco Oil Belt (FPO) area. While reserves have remained in similar massive quantities for the last few years, they consist mostly of extra-heavy crude oil, which cost of extraction and upgrading (or blending) tends to be significantly higher. In fact, a closer look reveals that developed reserves stand at 12,944 mm bbl. It is clear Venezuela's is not a reserves problem, but rather how to monetise the same by increasing production and exports.

Developing the said reserves requires a significant investment not only in production but also in upgrading the extra-heavy oil (EHO) to produce synthetic crude oil (SCO) which may be processed in refineries accepting such a diet or, alternatively, it requires combining the EHO with light oil in order for the same to be marketed as blend (diluted crude oil or DCO). Blending avoids the costs and time required for building the facilities to upgrade EHO, but requires large amounts of diluent (light crude oil, which has to be bought overseas) in order to blend and sell DCO (at a price lower than the price paid for the diluent). Since no new upgrading facilities have been built over the past 15 years, and the currently built ones are experiencing issues associated with maintenance and overhaul, most of Venezuela's strategy for the FPO is aimed at blending and exporting DCO.

The Government strategy of exporting DCO – in light of its inability to attract investments to erect additional upgraders under the legal, contractual and fiscal conditions in place – has been confronted with the broadening of U.S. sanctions (up to December 2018, basically aimed at PDVSA's finance-credit operations) to the sale and import into Venezuela of oil and oil products in January, 2019 as per Executive Order 13857, which directly restricts imports of oil and products (including nafta and light crude, which are used as diluent).

At the same time, Venezuela's oil and products exports have shifted and will continue to shift to a more crude oil-based trade with fewer products (hence incorporating less value), in light of the issues being experienced in PDVSA's manufacturing and marketing units, and since the deficit in diluent or light oil sourced from foreign providers must be replaced with local light crudes in order to produce Merey 16 (e.g. blending EHO with domestically produced light crudes from North Monagas such as Santa Barbara and Anaco Wax).

Far from effectively monetising its reserves, Venezuela has gone in the opposite direction. While for the years 2014 through 2017, production and exports largely missed the targets identified in the Venezuelan government's mid-term plan (*Plan de la Patria*) of producing 6.2 mmbpd and exporting 5.39 mmbpd of oil in 2019; during 2018 and the first half of 2019, production continued to experience a sharp fall. According to BP's *Statistical Review of World Energy* 2019, Venezuela's crude production dropped significantly, to over 1 mmbpd at the end of 2018. In fact, the second half of 2018 and the first half of 2019 have proven disastrous for Venezuela's public finances as production and export volumes have dropped to historical lows, even while the prices of oil and oil products in international markets have been steadily rising and have been sitting well over 50 US$/bbl, which has further increased the price of the Venezuelan basket (at the close of March, 61.60 US$/bbl for the Venezuelan basket vs 67.57 US$/bbl for Brent and 59.3 US$/bbl for WTI).

According to OPEC's monthly oil report dated July 11, 2019, Venezuela's crude oil production shrank from 1,911 mbpd in 2017 to 734 mbpd in June, 2019; the fall is particularly grave in light of different issues, all of them material, which make it possible to forecast that production is unlikely to increase in the near future. Venezuela dropped below the historical threshold of 1 mmbpd back in January 2019 (since 1946 Venezuela has permanently produced more than 1 mmbpd, excluding only the two-month hiatus resulting from the 2003 PDVSA strike) and does not seem likely to recover any time soon (estimates by the Oxford Institute for Energy Studies set production somewhere between 0.6 mmbpd and 0.8 mmbpd).

Such a structural decline is the result of long-standing poor policies and a business structure that is highly concentrated on Venezuela's instrumentalities, where even in joint venture structures with private investors (*Empresas Mixtas*), PDVSA continues to bear a significant financial burden it cannot cope with. Said decline was foretold by many experts (*Cf*. Ramón Espinasa, among others) but has spiralled as a result of Venezuela's dire economic situation where there is a material loss of human capital (more than four million people have fled the country), PDVSA's virtual bankruptcy and financial opacity, decaying exploration & production (E&P) and manufacturing and marketing (M&M) infrastructure, massive power generation outages since late 2017, and on a more material level since January 2019, the implementation of U.S. sanctions against the Maduro government, including PDVSA and its affiliates.

The flight of human resources has been estimated to have drained most of PDVSA's knowledgeable and skilled management and workforce. As has been documented, PDVSA's payroll continued to increase from a little under 42,000 in 1999 (*Cf*. PDVSA Statistical Report) to a little over 152,000 in 2014. In 2015, however, PDVSA workers began a steady exodus that grew into an stampede in 2017 and 2018 in the wake of economic turmoil and the ensuing persecution which developed after the change in management in late 2017 (including criminal charges and unlawful detentions of the former PDVSA President, senior and middle managers, *et alia*) . While PDVSA has not released its 2017 nor 2018 financial and operational statements, estimates indicate the number of employees dropped from 146,226 in 2016 to 121,800 in 2017 – a 17% loss; and a further drop in 2018, with an overwhelming reduction to 103,331 by the end of September 2018 (*Cf.* IPD LatinAmerica reports for 2018). While there are no official figures for the first half of 2019, informal estimates put the number in the mid-80 thousands. Making matters worse, those who have fled tend to be best qualified and engaged in core activities, leaving PDVSA with a dead weight. Regrettably, the said brain drain has expanded to the joint ventures (*Empresas Mixtas*) with private parties.

With regard to PDVSA's financial prowess, according to an extract of PDVSA's consolidated financial debt published on January 22, 2019, as mandated by the Master Law of Financial Administration of the Public Sector, PDVSA's total consolidated debt fell 5% in 2018 to US$ 34.55 billion (from $36.35); nevertheless, such reduction may prove artificial, since the figures do not include PDVSA's default on interest for over $1.99 billion on PDVSA bonds during 2018, nor another $1 billion in defaulting PDVSA Promissory Notes on its balance sheet, and have yet to account for awards from arbitrations and other claims against PDVSA.

It is estimated that both the Republic of Venezuela (PDVSA's sole shareholder) and PDVSA retain outstanding financial obligations of about US$ 160 billion as of June 2019. To make matters worse, both Venezuela (Sovereign) and PDVSA have defaulted on their international (and local) financial obligations (bonds) since October 2017 (when all grace periods ended for payment of interest and, in some cases, principal) which, at the close of 2018, amounted to US$ 8.7 billion in coupons and principal payments (with the exception of the PDV2020 bonds, which are secured with about half the shares of Citgo Holding). The situation is critical as most bond indentures cover acceleration provisions and some even include cross-default clauses which, if enforced, would largely bankrupt PDVSA.

With regard to E&P operations, the average number of drilling rigs in operation is reported to have fallen to 22 as of March 2019 (see reports by Baker Hughes) as compared to 48 in early 2018, and PDVSA continues to struggle with large rig operators in light of extended payment issues, and more recently the U.S. sanctions. In fact, the U.S. Treasury Licenses afforded to some major U.S. and international rig contractors and operators Halliburton, Schlumberger, Baker Hughes, and Weatherford (under License 8C) while extended under the current Executive Order 13884, are due to sunset as early as October 25, 2019.

Even though oil prices have stabilised in comparison with previous years, the sharp reduction in production has worsened the major economic crisis being suffered by Venezuela, whose national budget largely depends on oil exports (over 96% of its exports). According to *Wood Mackenzie's Venezuela product markets long-term outlook* H1 2019, given the country's strong dependence on oil exports, its GDP is expected to decrease by 21% in 2019.

The U.S. sanctions will only make matters worse. Any alternative for moving forward in a proper reconstruction effort will require:

- a change in administration;
- the sanctions to be lifted (which is likely tied to such a change); and
- the new government devising a legal and institutional framework and generating trust which attracts private investors, allowing for needed investments, but also allowing Venezuela to release financial resources which are gravely needed in dealing with debt service and supplying basic public goods to the Venezuelan population.

Developments in government policy/strategy/approach

Oil

Upstream. As Venezuela's output is made up of PDVSA's own production plus production by joint ventures with private parties through *Empresas Mixtas* (where PDVSA owns a majority stake), the Venezuelan Government, through PDVSA, sought to turn back the decline by inviting and assigning areas under risk service agreements for enhanced oil recovery (EOR) in 14 mature fields.

Whether in respect of its own production or that of the *Empresas Mixtas*, PDVSA faced material restrictions in its ability to pursue financing (100% in its operations and at least 60% in the joint ventures), due to its limited ability to pursue new financings or restructure prior financings (the same has been in default for all of its bonds but for the PDV2020 – where 50.1% of Citgo shares are pledged), while U.S. sanctions (Executive Order 13808 of August 2017), had imposed restrictions on its ability to pursue credit.

According to statements by Minister Quevedo (who also acts as PDVSA President) back in August 2018, the aim of the agreements was to increase output by 167% for the said areas in less than a year, increasing production of 384 mbpd by 641 mbpd to 1.25 mmbpd, with an investment by contractors of US$ 430 million.

Only one of the 13 companies which were awarded has international operating experience (Shandong Kerui Group from the People's Republic of China (PRC), which was awarded the Dación area); most awarded companies were small, local contractors without prior experience. Of the 14 mature fields awarded, only eight were currently producing; the remainder were idle. Local contractor Venenca was awarded the most material fields (Carito-Pirital), producing Mesa 30 crude used to dilute EHO.

The negotiation and execution of the same was shrouded in secrecy (neither the draft nor the executed agreements were or have been submitted to the *Asamblea Nacional* to date); no actual bidding or auction took place, but rather direct negotiations under an "emergency Decree", which make it difficult to identify the particulars of the agreements.

From what is known, the agreements encompass a more basic transaction than prior risk service agreements (such as the 1990s Operating Services Agreements – OSAs). It is clear that the model was influenced by restrictions in financing PDVSA under U.S. sanctions, as one important feature of the agreements is that they do not clearly cover the treatment and characterisation of expenditures and their recovery, such as the OSAs did. The agreement remains a risk service contract where expenditures (capital and operating) are borne by the contractor, which is ultimately paid at certain milestone dates based on a function of output, which payment includes fees associated with base production and fees linked to incremental production. The term of the agreements is six years. Two key features from the transaction structure are a side agreement, where contractors are entitled to receive payment directly from offtakers, and exclusion of measures issued under sanctions from the definition of *force majeure.*

In addition to the said agreements, other "minor" services agreements were negotiated and entered into throughout 2018, which can also be characterised as risk contracts. They are more basic in their design and have a term of two years, which may be extended for an additional year; most contractors seem largely inexperienced and with little financial muscle. For the same, no actual blocks or areas were awarded but rather wells, then run by PPSA in different areas of the country, were identified for servicing.

In September 2018, PDVSA concluded negotiations with China National Petroleum

Corporation (CNPC) for the latter to buy part of PDVSA's stake in FPO Petrolera Sinovensa, S.A. *Empresa Mixta*; this being the first time PDVSA divested to the minimum provided by law (its standard practice has been to hold up to 60% stake in the *Empresa Mixtas*) of over 50%. The purchase follows nearly two years of production declines, with control of operations in the hands of PDVSA.

Back in 2013, the China Development Bank extended a US$ 4 billion credit line to the *Empresa Mixta,* which had only been executed up to 39% at the close of 2017. Sinovensa production has recovered since, but has not yet reached its peak of 166 mbpd back in October 2015 (below its 330 mbpd estimated production capacity) in light of different issues, lately including delays in procuring diluent supply from PDVSA and third parties. While the purchase did not include a change in the control provisions of the joint venture, in practice CNPC has been bearing practical control of the operations, which has resulted in an increase in production over the 100 mbpd, but still well under its peak and its estimated production capacity, and the same was adversely affected during the first half of 2019 by the energy blackouts.

In December 2018, Shell farmed out its 40% stake in Urdaneta Oeste block *Empresa Mixta*, Petroregional del Lago, S.A. after obtaining approvals from Class A shareholder PPSA and the Government of Venezuela. The buyer, French company Maurel & Prom, agreed on a €70 million price and agreed with the Government and its co-venturer on a five-year development plan requiring investments of about €350 million.

Venezuela has continued to publicly express its support for the PetroCaribe energy supply agreement (18 countries participate in the same, Venezuela being the sole supplier) but in practice, the current drop in oil production has resulted in a major shrinking of its supply commitments (under PetroCaribe and similar agreements, Venezuela was to supply crude oil and products at reduced prices and/or at credit; oil purchases were financed up to 80%, payable over 25 years at 1–2% interest rates and with a two-year grace period; in addition, the part of the bill that is due in cash can be paid for in kind). The main beneficiary remains Cuba, which throughout 2018 received exports of oil and products amounting to close to 70 mbpd.

Venezuela's export strategy during 2017 and 2018 aimed at Asian countries, mostly the PRC and India, as well as Russia; it now seems PDVSA's only available option (due to the January, 2019 sanctions limiting U.S. Companies and companies with presence in the U.S. from purchasing oil and products from PDVSA, but for the limited licences issued to date), as sanctions forbid U.S. clients from paying the Maduro administration and instead, payments go to an escrow account on behalf of the "interim government". Citgo Petroleum Corporation, the United States-based refiner which is majority-owned by PDVSA, has received no cargos since the sanctions were implemented (and most Gulf Coast refiners have replaced supply with Canadian, and even Russian oil). The U.S. has put significant pressure on actual or potential buyers during the last couple of months, as Spain's Repsol, India's Reliance and even China's CNPC can attest.

In any case, the main client through 2018 and the first half of 2019 has been Rosneft, which on top of its participation in FPO projects, has been leveraging its financial dealings (as those of the Russian Federation) with Venezuela and PDVSA to support the purchase of crude oil and DCO from Venezuela, partly setting off against outstanding amounts (the debt was estimated at US$ 2.3 billion for January, 2019). In fact, experts indicate that Rosneft has become a main trader for Venezuela's oil (*Cf.* Bloomberg, IPD) allowing Venezuela to work around, at least partially, the sanctions scenario (Rosneft took about 62% of all cargoes loaded at the Jose terminal as of May 27; however, the data seems to reveal that a significant portion of these cargoes were re-nominated to, or taken on behalf of, other clients).

The second-largest market is the PRC. The PRC decided back in 2018 not to renew the prior waiver (reduction) on Venezuela's debt under the Great Sino-Venezuela Fund (which is to be paid, at the discretion of the PRC in US$, Renminbi or oil and products), expanding the volumes of oil and products associated with the relevant instalments (estimated at over 350 mbpd of oil and products throughout 2018).

The third large client for 2018 and the first quarter of 2019 has been Reliance, from India, which has proven a significant support and a cash generator for PDVSA. As of lately, the same has pledged to the U.S. Trump administration not to continue to pursue business from PDVSA, whether supplying light crude or nafta or purchasing crude or products.

Downstream. Venezuela's refining crude runs have been in a steep fall since 2015 as local refineries have suffered a variety of operational problems, lack of crude oil feedstock, human resource issues, and infrastructure challenges which have resulted in the same processing no more than 280 mbpd during 2019, which represents 22% of their installed capacity (*Cf.* Wood McKenzie).

Back in the first quarter of 2018, the Government announced plans for Rosneft to handle the Amuay refinery (with overall capacity of 650,000 barrels per day), while China's Petrochina was to take over the Cardon refinery (with a capacity for producing 310,000 bbl). The plans did not go through due to the significant investment involved in bringing the facilities up to speed and the lack of legal standing under the law (LOH) of any agreement in which the whole operation of the refineries is handed over to private parties.

In December 2018, the Puerto La Cruz refinery was shut down. Cardon operations were halted on May 15, 2019. Some of the units (catalytic reforming unit) were restarted in mid-June, while the rest of the units remain non-operational. As such, Venezuela's domestic refining system relies almost solely on Amuay. Amuay currently processes about 200 mbpd. In June, PDVSA announced its intention to restart Amuay's hydro-desulphurisation unit (HDAY-3) to process 85 mbpd of vacuum gas oil (VGO) to feed the fluid catalytic cracker (FCC), with the aim of increasing gasoline production to 115 mbpd (as at this time, domestic supply relies on imports). In any case, experts estimate the said increase will not exceed 70 mbpd, and other units that are key to gasoline manufacturing, including the alkylation (ALAY) may prove troublesome. Between January and May 2019, PDVSA imported an average 122 mbpd of finished products and components. The State-owned oil company has somehow found a way around U.S. sanctions, as Rosneft has become Venezuela's main product supplier, with 46% of cargoes for the first quarter of 2019.

<u>Gas</u>

Natural gas production has been falling since 2016, which is the necessary outcome of the fall in oil production, as 90% of Venezuela's natural gas production is associated with oil extraction. Experts estimate the decline between 2016 and 2018 to be about 1.5 bcfd (from 7.9 bcfd to 6.3 bcfd). Further, gas production has continued to drop again between January and June 2019, to average around 5.7 bcfd (also as a result of the blackouts). Strikingly, gas losses due to venting, flaring and operational issues appear to have remained constant, holding at an average 2.1 bcfd between 2016 and 2018, and 1.9 bcfd between January and May 2019. Gas waste due to flaring and other operational issues is estimated to run from 8% to 19% depending on the area (*Cf.* IPD LatinAmerica), well above international standards.

The drop would have been worse if gas licence production had not remained relatively stable (production dropped about 153 mm cfpd between 2017 and 2018, and remained stable during the first half of 2019, at an average 750 mm cfpd).

Onshore producing licences (Yucal Placer, Quiriquire Gas and Gas Guarico), with an actual production of less than 300 mmcfd, have seen the expansion of their facilities and increase of their production limited due to restrictions to access foreign currency (CAVIDI/CENCOEX/SMC) for investments and, since the licensees have not been successful in negotiating with the Government, the application of a mixed tariff (combining US$ and Bs) on the output (all of which is destined to the local market). Furthermore, from June 2016 to January 2018 the onshore licensees worked under a transitional agreement with PDVSA Gas which resulted in payments amounting to the cash flows required to cover for operational and capital expenses only. This critical situation is compounded by the licensees continuing to experience material delays in payment by PDVSA Gas, hence limiting payment of their personnel payroll, critical services and purchase of spare parts to secure the safe operation of their facilities.

At this time, negotiation of new conditions for the licences (i.e. terms for supply) and for pricing and tariffs, in line with devaluation and inflation, which include a mixed tariff, has become an urgent matter to make the onshore licences economically viable. Offshore Licence Cardon IV has an actual capacity to produce 540 mmcfd, with a potential for 1,200 mmcfd, and the same is also experiencing material delays in payment by PDVSA Gas, and restrictions associated with the possibility to export part of its output, to allow the project to run in a far more efficient manner.

Rosneft was awarded a licence to develop natural gas off the coast of Paria (over the Mejillones and Patao areas) back in December 2017. The licence does not require Rosneft to enter into a joint venture with PDVSA, and allows Rosneft to keep positive control over decision-making and operations when and if incorporating PDVSA. The licence allows for exporting the full amount of gas produced or processed into LNG through an offshore floating facility, minus gas to be supplied to Venezuela as royalty and additional advantages in kind.

A reversal in the flow of the Gasoducto Transcaribeño running from Paraguaná to the Ballenas field, outstanding for the last couple of years (originally estimated for December 2015) will remain stagnant as a consequence of the current gas production decline and supply reduction in western Venezuela. Plans of the Venezuelan Government from 2017 to export gas to Colombia on the basis of production from Cardon gas field (ENI/Repsol) in north-western Falcón State did not proceed as the project has not been able to achieve its full potential in light of pricing and supply restrictions, and since its output has been largely used to make up for the other missing production. As referred in prior reports, the flow of gas from Colombia was stopped in early 2016 due to lack of and late payment.

Electricity

Energy generation, transmission and distribution are in crisis. As mentioned earlier, an important breakdown in the country's most important transmission grid from the Guri dam (hydropower generating facility) led to a series of major nationwide blackouts throughout the first half of 2019. These blackouts affected (and continue to affect) the country as a whole. In response, the Government is implementing scheduled and unscheduled rationing and power outages. In addition, the government has reduced, indefinitely, public officers' work day to just six hours a day.

Works to restore Venezuela's electricity system may take up to a year, according to Electricity Minister Igor Gavidia (appointed on April 1, 2019), which devised a plan in broad lines but with little information about its implementation or how the same would be financed. The plan included a schedule for electricity rationing for Venezuela, excluding Caracas and three other States, according to which the general public would be without energy for at least 18 hours per week (dividing the country into five sectors with different rationing schemes, with the idea of implementing daily three-hour blackouts six days per week). The rationing measure specifically excludes the State of Vargas near Caracas where Venezuela's main airport is located, along with the southern State of Amazonas and the northeastern State of Delta Amacuro, border regions far from the capital. In practice, rationing goes well beyond programmed cuts in many areas of Venezuela, and has hit the west of Venezuela most, where blackouts in Zulia State may extend for days (the average temperature for Zulia is 34^{o}C).

Then again, the ability of the Government to pursue recovery is further restricted by a flight of human capital in CORPOELEC, its financial woes (electricity was heavily subsidised and only as of recently – June forward – have utility prices been growing, and only for a very reduced section of the population), and the limited access to first-tier service providers, be it for maintenance, repairs or other support in light of the U.S. sanctions. (While in principle, up to August under Executive Order 13884, there was no broad restriction on the provision of said services, but rather special licences allowed for the same, which have been extended by new licences under Executive Order 13884, there is clearly a fallout from the sanctions, which affects – in practice – the provision of services in this area by U.S. and foreign firms with interests in the U.S.)

Developments in legislation or regulation

As referred in prior reports, the main legislative body, the *Asamblea Nacional* (AN), has been controlled by opposition parties since December 6, 2015, and since early 2016 the Executive has assumed emergency powers, while a rigged Supreme Tribunal of Justice has thwarted any attempts by the elected AN to produce significant lawmaking, or exercise oversight and control over the public administration and PDVSA.

In addition, in the middle of 2017 the Government advanced rigged elections for a National Constituent Assembly (ANC), entrusted to craft a new Constitution. In practice, the ANC has been passing laws. Further, in mid-2018 the Government anticipated presidential elections, which resulted in the re-election of the incumbent. The said elections have also been considered as fixed and illegitimate by a vast number of countries.

As a result, the legal framework during 2017 and 2018 has incorporated laws and regulations issued by the National Government, the ANC, and even the Supreme Tribunal of Justice (which has amended standing laws) while all laws passed by the AN have been struck out as unconstitutional by the Supreme Tribunal of Justice.

The situation got more complex in February 2019, as Maduro's original term as president had lapsed and he is no longer recognized as President by the AN and a group of more than 60 countries. The AN president was appointed as interim president and on February 5, 2019, Venezuela's National Assembly passed the "Statute Governing the Transition to Democracy" ("Transition Law"). This new law delineates a roadmap for the country's political transition, based on Article 333 of the Constitution.

The Law sets a specific transitional regime for PDVSA and its subsidiaries whereby the Interim President can appoint a PDVSA board on an *ad hoc* basis. Board members may live abroad and have all powers and responsibilities associated with the PDVSA Shareholders Assembly. The PDVSA board will be able to take "all necessary actions" to appoint PDV Holding, Inc. board members. The board will be in charge of appointing other PDVSA subsidiary boards, including that of Citgo.

While not recognized by Venezuela's government and struck down by the Supreme Tribunal of Justice, the Interim President has appointed ambassadors overseas, representatives before International Financial Institutions such as the IMF and the World Bank, an Attorney General, and a Board for PDVSA, PDVSA Holding, Inc. and Citgo. The latter have been recognized by the U.S. government and represent the said companies in the U.S. (as well as in other countries, as it happens, by virtue of PDVSA's participation in Nynas AB).

On the domestic front, as referred to above, the government has made use of its self-endowed emergency powers to advance some changes to the oil and gas legal and regulatory framework, with certain measures adopted which impact investors engaged in oil and gas projects, such as amendments to the corporate income tax law back in 2015 and the passing of a financial transactions tax, as identified in prior reports.

In the past year, the government has been more active. In April 2018, Decree 44 was issued allowing broad powers to the Ministry and PDVSA to select and advance contracting services for PDVSA and the *Empresas Mixtas*, as the Decree provided broad discretion in bypassing rules under the Master Hydrocarbons Law (*Ley Orgánica de Hidrocarburos*), the Public Procurement and Contracting Law (*Ley de Contrataciones Públicas*) and the Master Law on Public Property (*Ley Orgánica de Bienes Públicos*). Said Decree was used as a basis for awarding drilling services under a risk service structure, and for ultimately awarding 14 areas under risk service contracts during the second and third quarters of 2018.

On July 10, 2018 the AN passed an amendment to the Master Law which Reserves Property and Services Connected to Primary Hydrocarbon Activities (*Ley Orgánica que Reserva al Estado Bienes y Servicios Conexos a las Actividades Primarias de Hidrocarburos*) of 2009. The amendment aimed at allowing ample participation of private parties in the provision of services to oil upstream operations (the 2009 law provided for unpaid expropriation of assets used in the said activities, i.e. confiscation, and restricted private participation in said activities, allowing solely for entering into joint ventures with PDVSA entities such as PDVSA Servicios, S.A. for the carrying out the same). The Executive vetoed the law and the AN did not advance further with the same.

<u>Foreign currency exchange</u>

In August 2018, a new Exchange Agreement No. 1 (*Convenio Cambiario* No. 1) ("CC1") was issued. Under the same, all prior foreign currency exchange agreements entered into between Venezuela's Central Bank (BCV) and the Government of Venezuela were replaced, thus making CC1's provisions the single framework applicable to all transactions in relation to foreign currency exchange.

Its main object, according to its provisions, was to establish a "free convertibility" policy within an organised market. In principle, the exchange rate is to be determined by the laws of supply and demand; however, the BCV is still the competent body in charge of fixing the applicable exchange rate, based on the movements of the Exchange Market System. The official exchange rate is set as of the beginning of August 2019 at VEB 15,700 per US$ 1.00.

Like under prior exchange agreements, CC1 establishes a mandatory sale to the BCV of foreign currency obtained from oil and gas exports (now covered under a single regime), whether carried out by PDVSA and its affiliates, *Empresas Mixtas* or upstream gas licensees. Nevertheless, in the case of PDVSA and its affiliates, CC1 allows amounts to be kept aside to cover their obligations in foreign currency (provided they relate to payment of "foreign component", expanded to maintenance expenditures and technical assistance) as set by the Government and Venezuela's Central bank, while in the case of *Empresas Mixtas*, the limitation related to foreign component is not present. In the case of gas licensees, there is a broad provision allowing the same to keep foreign currency to pay for any and all expenditures associated with the licences, including investments and reinvestments. None of them are allowed to pursue foreign currency from the SMC (*Sistema de Mercado Cambiario*).

Under the current F/X regulations and CCs, there is no requirement for contributions in foreign currency, or loans granted to companies incorporated in Venezuela, or to branches of foreign companies set up in Venezuela, to be brought into Venezuela or transformed into Bolivares.

<u>Tax changes</u>

Throughout 2018 the Government also issued broad tax holidays for the import of goods associated with E&P and refining activities, basically allowing a full exemption from VAT and import tariffs. In addition, on August 1, 2018, the Government issued Decree 3569, covering for a full tax holiday on corporate income tax for FY 2018 applicable to PDVSA affiliates and *Empresas Mixtas* engaged in oil-producing activities.

The financial transactions tax was introduced in late 2015, triggering a levy of 0.75% applicable not only to withdrawals on accounts held in local banks and financial institutions, but also on the set-off, payment or settlement of obligations in general (e.g. payment of signature bonuses). On September 1, 2018, the tax rate was set at 1%, in accordance to the Amendment of the Law of late August, 2018. According to the amendment, the National Executive may, at its own discretion and by means of decree, fix the rate of this tax from a minimum of 0% to a maximum of 2%. On November 8, 2018, the rate was increased to the maximum of 2%.

Municipal taxation (tax on economic activities) has suffered some changes between late 2018 and the first half of 2019. Some municipalities have decided to adopt means to avoid losing revenue due to the raging inflation. Among these mechanisms, the most important municipalities have applied advance taxes on a monthly or even weekly basis.

Additionally, just in July, 2019 a net equity tax law was passed by the National Constituent Assembly. This new tax applies to those taxpayers identified as special taxpayers (*sujetos pasivos especiales*) whose equity is equal or superior to 36 million tax units (US$ 239,875, applying the official exchange rate), and such characterisation is commonly afforded to entities engaged in oil and gas activities. The rate may be changed by the National Executive between 0.25% and 1.50%, and the law sets it initially at 0.25%. There are many elements not clearly defined in the law and others which are to be defined by Regulations. The Authorities intend to apply the tax from the close of September 2019.

Judicial decisions, court judgments, results of public enquiries

Exxon-Mobil ICSID case (No. ARB/07/27), covering the expropriation of its interests in the *Cerro Negro Asociación Estratégica* of the FPO, and the Sole Risk Exploration and Production Sharing Agreement for La Ceiba, remain pending after Venezuela's counsel filed for an extraordinary measure of resubmission. As it may be recalled, the final award in favour of Exxon-Mobil was submitted to an extraordinary annulment process under ICSID, as requested by Venezuela (on February 9, 2015), and which was decided on March 9, 2017 by the *ad hoc* committee constituted for such purpose, declaring the partial annulment of the final award in favour of Exxon-Mobil, particularly regarding the compensation basis for the expropriation of the Cerro Negro Project. On October 24, 2018 Venezuela applied for resubmission. The proceedings remain pending.

The situation remains entangled in the case of Conoco-Phillips (ICSID Case No. ARB/07/30). As it may be recalled, a decision on jurisdiction and the merits was issued on

September 3, 2013. In its decision, the arbitration panel upheld the request for compensation for breach of Article 6(c) of the BIT as the expropriation was unlawful, since Venezuela had not negotiated compensation in good faith. While the decision on the merits was final, the same did not constitute the final award, as a determination on the quantum was pending. On March 8, 2019, the tribunal issued its decision on quantum. The award established as main amounts that Venezuela must pay ConocoPhillips the following:

(i) US$ 3,386,079,057 to ConocoPhillips Petrozuata B.V. for the expropriation of its interest in PETROZUATA, S.A.;
(ii) US$ 4,498,085,150 to ConocoPhillips Hamaca B.V. for the expropriation of its interest in the Hamaca Project; and
(iii) US$ 562,140,959 to ConocoPhillips Gulf of Paria B.V. for the expropriation of its interest in the Gulf of Paria East and West blocks.

Since the issuance of the final award, Venezuela's representation filed a request for the initiation of a rectification procedure (on quantum) which was registered by the tribunal on April 18, 2019. On May 10, 2019, the representation of ConocoPhillips filed a writ of observations to the request for rectification procedure filed by the representation of Venezuela.

In April 2018, a domestic Curacao court approved Conoco's petition to seize PDVSA assets in the Caribbean, aimed at enforcing its April 2015 ICC US$ 2.04 billion ruling (confirmed on April 24, 2018 award 20549/ASM/JPA, in the case between Phillips Petroleum Company Venezuela Limited, ConocoPhillips Petrozuata B.V., as claimants, and Petróleos de Venezuela, S.A., Corpoguanipa, S.A., PDVSA Petróleo, S.A., as respondents). The ruling resulted in Venezuela limiting the supply of oil and products to its Caribbean facilities, including the Isla refinery in Curacao.

PDVSA and Conoco reached a settlement agreement in October 2018 under which PDVSA committed to pay US$ 500 million before the end of the year, while the remainder was to be paid on a quarterly basis over the next four-and-a-half years (1.66 million barrels of oil per quarter, or 18 mbpd). Cargoes are most likely to be heavy oil delivered to Conoco's Sweeny refinery, where PDVSA used to jointly own the refinery's delayed coker unit with Conoco (which stake was lost for lack of supply and payment). PDVSA paid the first US$ 500 million instalment with US$ 345 million worth of oil, and US$ 155 million in cash in November 2018. The settlement remains in place to date.

Major events or developments

The most significant development during 2018 and the first half of 2019 has been the imposition of sanctions by the U.S. Government through different Executive Orders (EO) to both individuals associated with the Maduro regime and certain entities, as well as pertaining to certain transactions with the Government and its instrumentalities (including PDVSA, its affiliates and *Empresas Mixtas*).

Sanctions have been imposed since Q3 2017 which extend their reach to certain transactions involving PDVSA or its property, namely:

(a) EO 13808 (August 2017), which prohibits the Venezuelan government, including PDVSA and Citgo, from accessing U.S. financial markets (including old debt and new debt, but for some very limited financing, as allowed by the EO, and the different licences issued), the EO specifically restricts the Venezuelan government's access to U.S. debt and equity markets, and the payment of dividends;
(b) EO 13827 (March 2018) which prohibits transactions that involve the Venezuelan

government's use of digital currency;

(c) EO 13835 (May 2018), which prohibits transactions related to the purchase of Venezuelan debt (i.e. credits in favour of Venezuela or PDVSA), including accounts receivable, and any debt owed to Venezuela pledged as collateral;

(d) EO 13850 (November 2018), which prohibits gold sector operations and the provision of financing support and services for the Government of Venezuela, and projects in which the same participates and which are designated by the U.S. Treasury Department as having incurred in bribery or fraud; and

(e) EO 13857 (January 2019) which expands the definition of Government of Venezuela to include PDVSA and Venezuela's Central Bank, for the purposes of all prior EOs. As a result, Venezuela was included, pursuant to EO 13850, as a Specially Designated Nationals and Blocked Persons list – ("SDN List") in January 2019.

EO 13884 was published on August 6, 2019, and the same: (a) blocks all Government of Venezuela (including PDVSA, its affiliates and the *Empresas Mixtas*) property and property interests in the United States or which come into the possession or control of a U.S. person, so that they may not be "transferred, paid, exported, withdrawn, or otherwise dealt in"; and (b) blocks all properties and interest in property of any person who has materially assisted, sponsored, or provided financial, material, or technological support to any person included on the list of Specially Designated Nationals. The EO also establishes an immigration ban for sanctioned persons, with the ability for the U.S. Treasury Secretary to lift the said ban in consultation with the Office of the Attorney general and the Secretary of Foreign Affairs.

EO 13884 is considered the most expansive of all, but its scope does not result in an embargo on Venezuela nor PDVSA, but the issues arise from the listing of PDVSA as a Specially Designated National, and the more expansive language of EO 13884 *viz* EO13850.

The EO, and the 28 Licenses which have been amended or issued pertaining to the same, do not prohibit transactions related to "the provision of articles such as food, clothing, and medicine intended to be used to relieve human suffering," and they de-restrict some activities between the private sector and the Venezuelan government, including: payments linked to telecommunications and mail; certain software and hardware services; patents, trademarks, and copyrights; and overflight payments, emergency landings, among others.

License 2A allows transactions in old debt and debt for Citgo Holding and PDV Holding; License 7C broadly allows transactions with PDV Holding, Citgo Holding and its affiliates (controlled by the Venezuelan AN; Licenses 11 and 13C broadly allow transactions with Nynas AB; and Licence 8C allows the operation in Venezuela of Chevron Corporation, Halliburton, Schlumberger, Baker Hughes, and Weatherford up and until October 25, 2019, Additionally, General License 28 provides a grace period, which expires on September 4, 2019, to wind down operations linked to the Venezuelan Government (including PDVSA and its affiliates).

It is clear in the wording of the licenses and the Q&A of the U.S. Office of Foreign Assets Control (OFAC), that the purchase of oil and products from PDVSA and its affiliates, as well as the import of oil, products and diluents into Venezuela are transactions which the US government aims at curbing.

While at this time, the full impact of the sanctions remains to be seen with regard to parties which are not U.S. persons and are potential suppliers or buyers to PDVSA, its affiliates and the *Empresas Mixtas*, such impact includes a fallout which extends beyond the ability of the US government to apply the sanctions, and which is associated with how the international financial systems views the sanctions.

To date, Venezuela has borrowed US$ 49bn from China, repaid with oil shipments from PDVSA (according to commentaries from MPPPM, up to US$ 27.2bn has already been repaid). Exports to China during 2015 to meet obligations under the same are identified by PDVSA as 627,000 bpd. The same places significant pressure on PDVSA's finances, which is the reason Venezuela tried unsuccessfully to renegotiate the terms for supply throughout 2015 and 2016, with little success.

Oil & Gas

Rosneft continues to advance with its investments in Venezuela at a steady pace after it raised its stake in Petromonagas to 40%, and it is said the same has been allowed to advance with operational decision-making.

Venezuela continues to barter its crude and products in an effort to avoid transacting via the U.S. financial system. While the Russians and the Chinese have proven hesitant to continue their oil-for-loans programs for some time, recent oil-for-services agreements with Chinese contractor, Wison Engineering and Swiss contractor Sulzer, for the repair of PDVSA's ailing refining system, confirm that Venezuela may have options. Shanghai-based Wison Engineering agreed, just at the beginning of August 2019, to shore up Venezuela's decaying refining network to ease fuel shortages. The deal is said to encompass payment for services with diesel fuel in a barter deal for urgent repairs.

Offshore gas projects. Rosneft received an E&P licence for the Patao and Mejillones areas in December 2017, and has advanced during the last year with basic engineering and definition, procuring certain fiscal advantages through tax holidays covered in government-issued Decrees, as well as under an Intergovernmental Agreement IGA (treaty) in place between Venezuela and the Russian Federation. At this stage, feasibility studies are well under way to try to identify: whether the project will encompass the setup of a floating facility with two trains for producing LNG offshore; whether part of the same will come to Venezuela (on top of royalties in kind to be paid to Venezuela); or whether the gas will be rerouted to T&T in order to be monetised in the LNG and petrochemical facilities in place there.

PDVSA underwent negotiations with Shell during most of 2018 for an alternative which would allow the development of the Dragón field, and the transportation of gas produced there to Trinidad & Tobago (T&T) by taking advantage of facilities already in place and managed by Shell in the Hibiscus field, offshore of T&T. The same included the possibility of licensing the field for a joint operation between Shell and PDVSA or, alternatively, entering into a service agreement under a build, finance and operate (BFO) structure. Negotiations seem to have stalled in light of the U.S. sanctions (in April, T&T authorities expressed concerns that Venezuela's Dragon gas deal was almost at a standstill).

With regard to Plataforma Deltana, according to T&T authorities, Shell has studied development options for an offshore natural gas field that straddles the maritime border between Venezuela and T&T, the cross-border Loran-Manatee field, estimated to hold about 10 trillion cf of gas. Loran-Manatee covers block 6 on Trinidad's side of the border, and block 2 on Venezuela's side. Shell acquired a 50% operating stake in Manatee, on Trinidad's side, from fellow major, Chevron in June 2017. Chevron still holds the remaining 50%. Chevron holds the licence on block 2, and an assignment would need to be authorised by the Venezuelan government for Shell to become a co-venturer, plus an amendment of the licence, which originally calls for output to be shipped to the mainland for processing in still non-existent and hardly developable LNG trains in Guiria, Sucre

State. Trinidad needs the gas to supply its industries, while Venezuela needs export revenue and has no infrastructure to monetise the gas on its own. Deltana Platform Block 2 conversations are now mostly on hold, due to U.S. sanctions.

Related to said projects, there is no news of further advances in the completion of the erection of the Dragon-CIGMA gas pipeline, nor on the erection of the PAGMI plant.

Proposals for changes in laws or regulations

In May 2019, a Bill for amending the Master Hydrocarbons Law (*Ley Orgánica de Hidrocarburos* or LOH) was introduced before the AN, together with Bills for different areas of the economy, set to have their discussion processes advanced and ready for an eventual regime change.

The Bill was a clear departure from the current law and the oil policies in place since 2001 (when the LOH was passed) and in line with policies adopted to foster investments in the legal and regulatory framework of other relevant countries (e.g. Brazil, Colombia, México, among many others), where:

(a) a Federal Oil Agency vested with a reasonable degree of technical autonomy would oversee the sector, the vesting of mineral rights and compliance with obligations and fiscal contributions;

(b) the State oil company role would participate as an additional player in the operating market; and

(c) the Ministry would set oil and energy policy.

The Bill also calls for the use of any and all means of participation by private investors in upstream and downstream activities (from licences, to participation agreements, to production-sharing contracts, to risk service contracts) to be identified by the agency for the relevant round, and allowed for trading and commercialisation (a major issue under the current LOH). The Bill also calls for the repeal of other laws which implemented Venezuela's oil policies to date, chief among the same being the repeal of the Special Petroleum Windfalls Contribution Law (*Ley que Crea Contribucion Especial por Precios Extraordinarios y Precios Exorbitantes en Mercado Internacional*).

In early July 2019 (but only made known in August 2019), the said Bill was set aside and a new Bill was introduced before the AN with a far more limited scope. Under the same, the vehicle for upstream private participation remains an *Empresa Mixta*, where the State-owned entity may hold any stake (i.e. even under 50%), and there is no reference to the thorny issue of positive control by the Venezuelan State stakeholder (which is not tied to owning a majority of the shares); additionally, any service agreements where the consideration (fee) is based on output will require prior approval from the AN, and both *Empresas Mixtas* and said service contracts would need to be "adapted" to the new law.

The Bill allows broad participation in downstream activities, especially in refining, and allows for commercialisation to be vested in the *Empresas Mixtas*; the bill also provides a quota system for national content (25% of all contracting-procurement for goods and services, starting from 5% and increasing every two years up to said 25%), and sets a special system for allowing the Operator to dispose of any associated gas, whether by reinjecting, flaring or selling the same (on its own or through agents), which is a carve-out from the regime provided under the Master Gas Hydrocarbons Law (*Ley Orgánica de Hidrocarburos Gaseosos* or LOHG). The Bill also covers the repeal of different laws, including the Special Petroleum Windfalls Contribution Law.

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Zimbabwe

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Overview of the current energy mix, and the place in the market of different energy sources

Zimbabwe relies for its energy supply on thermal energy, hydroelectric and, to a limited extent, solar energy. Zimbabwe still has huge deposits of coal, which is used in the generation of electricity. Zimbabwe has an installed capacity of about 2,300 MW. Approximately 95% of this is generated by the government-owned Zimbabwe Power Company (ZPC). More than 50% of electricity is generated from hydropower while the remainder comes from thermal power plants.

The total electricity supply as of 6th September 2019 was 740 MW, which was met from hydro (24.61%), thermal (45.67%) and imports (29.72%). Power generation from hydro has been severely affected due to a drought. The Kariba Dam's water levels have been severely depleted, hence the directive by the Zambezi River Authority to reduce generation.

While Zimbabwe is part of the Southern Africa Power Pool (SAPP), which has 12 member countries represented by their respective power utilities organised through the Southern African Development Community, and can obtain power supplies from the member states, its capacity to do so has been severely curtailed due to foreign currency shortages. For the greater part of the year, supplies were cut by ESKOM, the South African power utility company, due to non-payment of outstanding debts. Power exports to Zimbabwe were only resumed in August after a debt-settlement plan was agreed upon.

There are several projects that are under way: the electricity generation company owned by the government recently embarked on an expansion of its coal-fired power plants, which is expected to add an additional 600 MW from two plants. Plans are also under way to refurbish and extend the lifespan of the older coal power plants that are beyond their plant life. Though still in operation, they constantly break down, reducing the energy supply from thermal sources.

Solar energy has huge potential but contributes an insignificant amount to the national grid – for now, about 5 MW. There has been an increase in interest in solar energy generation for both on-grid and off-grid systems. Most of these projects are, however, still in their early stages.

Zimbabwe's population is largely rural and relies mainly on the use of biomass and petroleum products. In 2016, it was estimated that 67.72% of the Zimbabwean population was living in rural areas. Only 9.8% of that proportion had access to, or was using, electricity.

Changes in the energy situation in the last 12 months which are likely to have an impact on future direction or policy

The drought experienced in much of Southern Africa during the 2018–2019 rain season resulted in low inflows into the Kariba Dam, which has an installed capacity of 1,050 MW. This has resulted in a reduction of the water available for power generation. Consequently, the power generated from Kariba is now only about 360 MW – and falling, as the water is further depleted.

The independent hydro power plants in the Eastern Highlands have been equally affected by the drought. The constant breakdowns of the old thermal power plants at Hwange have resulted in reduced power generation. The power plants also experienced reduced supplies of coal, as coal producers have faced challenges arising from the inability of the power utility to pay viable prices for coal due to an unsustainable power tariff.

Lack of foreign currency to fund imports of power from SAPP members has also meant that the power supply available in the country is well below demand. The total supply of 740 MW (against a peak demand of 1,700 MW) has meant that the available power has had to be rationed, by resorting to load-shedding – with up to 18 hours of power cuts per day, in many instances. This has forced government and the business community to look at alternative sources of power, particularly solar. Many households have had to resort to off-grid solar solutions, and some businesses are also considering this as an option. Solar has the capacity to rapidly increase the power supply in Zimbabwe, while reducing dependency on imports of power. Solar solutions also have the potential to increase off-grid power supplies to many rural communities.

Developments in government policy/strategy/approach

1. On 5th February 2019 the Government announced plans to restructure ZESA Holdings (Private) Limited (ZESA) and to merge its subsidiaries (ZPC, ZETDC and ZENT) into a single, vertically integrated company. It was announced that three (3) subsidiaries would be merged back into one entity and Power Tel Communications, one of ZESA Holdings' four subsidiaries, would be transferred from ZESA and merged with government internet and telecoms providers ZANET and Africom. It was announced that plans were afoot to amend the Electricity Act [Chapter 13:19] ("the Electricity Act") in order to make provision for the new structure that had been approved by Cabinet. It was also announced that a consultant was being sought to advise the government on the best structure for the merged entity.

   The reasons given for the decision to merge the ZESA entities was the avowed desire to save on the high costs of running ZESA's five (5) entities and to stop the duplication of roles by the companies, which all had certain departments that were similar. The decision to merge ZESA and its entities into one company would be a reversal of the unbundling exercise undertaken by the government pursuant to the amendments made to the Electricity Act by the Electricity Amendment Acts of 2003 and 2007. The decision also constitutes a reversal of the Government's National Energy Policy which was launched in 2012. The decision to merge the ZESA entities would come at a time when the country had made strides towards the licensing of Independent Power Producers (IPPs) and the liberalisation of the electricity market.
2. The crippling power shortages have resulted in the government expediting the launch of the National Renewable Energy policy (NREP). The policy was launched in August

2019 and developed under the overall framework of the National Energy Policy of 2012. NREP seeks to promote the development and use of renewable energy sources in Zimbabwe, particularly solar, hydro, wind, geothermal and biomass. Most of these renewable energy sources remain unexploited and with a potential to generate more than Zimbabwe's energy requirements. NREP has set targets for the various renewable energy sources, with an ambitious target to have installed capacity of renewables of 1,100 MW or 16.5% of the total electricity generation (whichever is higher) by 2025, and 2,100 MW or 25.5% of the total electricity generation, whichever is higher, by 2030.

The policy also aims at: the removal of barriers to the deployment of renewable energy sources; the introduction of various incentives to attract private investors; a reduction in government bureaucratic delays in project approvals; the introduction of procurement guidelines; and viable pre-approved power purchase agreements and the provision of government funding in identified areas.

3. The shortages in power have also seen the government, through the Ministry of Energy and Power Development (MoEPD), announcing that it will withdraw the licences issued to some of the Independent Power Producers that have failed to start construction of their projects. This announcement, which was seen as too drastic by some of the players, will open up the renewable energy space to serious investors who have the capacity to acquire the licences and rapidly implement the projects.

Developments in legislation or regulation

There have been no developments in energy legislation and regulation since the promulgation of the net-metering regulations and the Electricity (Public Safety) Regulations in 2018.

Judicial decisions, court judgments, results of public enquiries

There have been no judicial, court judgments or results of public enquiries relevant to the electricity sector.

Major events or developments

The introduction of the load-shedding programme, as a result of the power shortages, was a major development that affected both the individual consumer and the business community. The government followed this up with a new tariff that seeks to punish high users of electricity.

Proposals for changes in laws or regulations

It is envisaged that new legislation and amendments to the existing pieces of legislation will come about as MoEPD starts implementing the various policy measures announced this year. The envisaged legislation would include: amendments to the Electricity Act, to provide for merging the ZESA entities; legislation to give effect to the NREP; and a policy for the withdrawal of licences issued to IPPs that have failed to execute their projects since they were issued with licences many years ago.

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