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In our eighth year of writing and publishing *The Energy Regulation and Markets Review*, we have seen geopolitical changes that have added significant uncertainties to global energy policies. For example, the uncertainties revolving around the United Kingdom’s exit from the European Union (a process known as Brexit) have led to uncertainties regarding the UK’s energy policies, including with respect to its commitments to reduce greenhouse gases (GHG). The US withdrawal from the multiparty international agreement with Iran this past year and the re-imposition of sanctions have had significant adverse energy investment impacts on Iran and other countries in the region. Despite the withdrawal of the United States from the Paris Agreement and expressions of support from the Trump administration for the coal industry, the United States has continued its extensive investment in renewable generation resources. The 2011 Fukushima nuclear incident continues to impact energy policy in many countries. Finally, we continue to see liberalisation of the energy sector globally.

## CLIMATE CHANGE DEVELOPMENTS

With respect to climate change developments, despite the US withdrawal from the Paris Agreement, we continue to see significant carbon reduction efforts globally, including increases in renewable resources, as well as energy efficiency and demand reduction measures.

In the United States, the Trump administration had pushed for a grid resiliency plan that the Department of Energy (DOE) issued in draft form that, if adopted, would have provided a benefit to the US coal industry; but the Federal Energy Regulatory Commission (FERC) voted unanimously to reject such a plan. A record number of coal and other aged fossil fuel plants retired this past year. Additionally, many states in the United States have pushed for the procurement of thousands of megawatts of renewable resources, including new offshore wind competitive procurements in the north-east. Furthermore, private companies have led the charge to contract for the long-term purchase of renewable energy.

Despite the United Kingdom’s continued efforts to follow through on Brexit, this was a record year for renewable generation development and a record low for energy produced by fossil fuel generation. As a result, the United Kingdom experienced a 43 per cent reduction in carbon emissions since 1990. In France, President Macron announced a goal to close the remaining four coal plants by 2022, and France targeted a 40 per cent reduction of GHG by 2030. Italy is seeking to achieve 30 per cent reliance on renewable energy and a 33 per cent reduction of GHG by 2030. Belgium continued its offshore wind procurement efforts, and is seeking to reduce subsidies in future procurements. Denmark is seeking to have all of its energy demand met by renewables by 2050, with 55 per cent reliance upon renewables by 2030. Switzerland is working to increase its reliance upon hydroelectric and other renewable
resources, and to reduce energy consumption by 16 per cent by 2020 and 43 per cent by 2035, compared to 2000 figures. Germany admitted that it would not meet its goal of reducing emissions by 40 per cent by 2020, as well as its goal to reduce energy consumption by 20 per cent since 2008, but it remains focused on renewable generation development, energy efficiency and conservation and energy storage technologies.

Japan continued its efforts to develop solar and wind resources, including opening new sea areas for offshore wind. But the shutdown of most of its nuclear generation has resulted in a significant reliance upon natural gas, including LNG. China set ambitious renewable energy goals, capping energy from coal generation to 5 billion tonnes and aiming to have 15 per cent of generation supplied by non-fossil fuel generation by 2020. Korea planned to abolish its old coal generation facilities by 2022, and committed to cut GHG by 37 per cent by 2030.

Australia began to focus heavily upon energy storage (battery and pumped water) and South Africa increased its renewable independent power procurement efforts.

II INFRASTRUCTURE DEVELOPMENT

For many countries, a reliable energy supply remains the primary concern, regardless of fuel source. As only 35 per cent of Myanmar is connected to the grid, Myanmar continues efforts to electrify remote parts of the country. Iraq continues to have significant infrastructure needs, and Panama and Colombia continue to seek foreign investment. Foreign investment in Iran will be significantly more challenging following the re-imposition of US sanctions.

South Africa is utilising its Integrated Resource Planning process to attract and develop new generation and transmission capacity. Australia is developing one of the largest pumped hydroelectric storage projects globally. Colombia is developing a large hydroelectric project that is expected to produce up to 17 per cent of the country's energy needs, but that effort is hindered by construction delays.

Denmark has five new applications for oil and gas exploration in the North Sea. In the United States, the DOE has issued a study authorising LNG exports to non-FTA nations, finding that the United States will experience net economic benefits from LNG exports, but efforts to develop oil and gas pipelines have been met with increased challenges from environmental groups.

III NUCLEAR POWER GENERATION

Eight years after the Fukushima disaster, Japan has stopped operations for 39 out of its 48 nuclear power stations, and 12 nuclear power stations are in the process of being reviewed for restart under Japan's new stringent safety standards. Germany continues efforts to phase out all nuclear generation, and Belgium's nuclear plants have been offline for maintenance for technical issues for the past few years. France was seeking to eliminate nuclear generation by 2025, but it extended that date to 2035. Korea continued its efforts to phase out nuclear power, abandoning the construction of six new nuclear plants and cancelling the life extension of 10 older nuclear plants. Switzerland shut down one of its remaining nuclear plants.

But the phase-out of nuclear energy is not universal. The United Arab Emirates’ new Barakah nuclear power station is 90 per cent complete, and South Africa is still considering building nuclear capacity after 2030. In the United States, even though the early retirement of certain nuclear plants has been driven by cost and power market considerations (rather
than safety concerns), some states have passed legislation to subsidise nuclear energy to allow owners to continue to operate through zero emissions credit programmes, including Illinois, New York and New Jersey, with similar legislation being considered in Pennsylvania and Ohio. While some parties challenged the constitutionality of these zero emissions programmes, two federal courts of appeals have upheld these programmes, and the US Supreme Court denied requests to review those decisions.

IV LIBERALISATION OF THE ENERGY SECTOR

We have seen significant energy sector regulatory reforms in many countries. The European Union has sought to continue efforts to centralise the regulation of the EU energy sector. France has taken significant steps toward further liberalisation of its energy sector, as has Switzerland. Japan fully liberalised its electricity sector, will be implementing unbundling next year, and is liberalising its retail natural gas and petroleum industries to encourage market entry. Australia has opened access to transmission through regulatory reforms to encourage entry into the generation market and has implemented significant market pricing response in response to the increase of renewables. Brazil is implementing net metering regulations this year and is implementing limited retail competition for large load. But the United Kingdom took a step backwards by implementing default price caps rather than market-oriented changes. In the United States, state subsidies for nuclear and renewable generation continue to threaten the effectiveness of capacity market regional pricing.

I would like to thank all the authors for their thoughtful consideration of the myriad interesting, yet challenging, issues that they have identified in their chapters in this eighth edition of *The Energy Regulation and Markets Review*.

David L Schwartz
Latham & Watkins LLP
Washington, DC
May 2019
Chapter 1

EUROPEAN UNION

Charles Morrison, Natasha Luther-Jones and Andreas Gunst

I OVERVIEW

The European energy markets are regulated primarily by a substantial body of European Union secondary legislation. Beyond the secondary legislation, which is comprised of regulations (directly applicable in Member States), directives (subject to transposition into domestic law), decisions (directly applicable and binding on the addressee), recommendations, opinions, and atypical acts (i.e., communications, guidelines, white and green papers), European energy market regulation needs to be understood in the greater context of a number of bilateral and multilateral treaties.

These include the European Union Treaties, namely the Treaty on the European Union (TEU), the Treaty on the Functioning of the European Union, the Treaty establishing the European Atomic Energy Community (Euratom), and the Charter of Fundamental Rights of the European Union. Other treaties include the Energy Charter Treaty, the Energy Community Treaty, pending the agreement establishing the World Trade Organization, the United Nations Framework Convention on Climate Change and the pending Paris Agreement, as well as bilateral investment treaties and bilateral project-specific agreements, such as pipeline or interconnector projects.

The 1994 European Charter Treaty, which builds on the 1991 European Energy Charter, is an unprecedented multilateral framework for international energy cooperation. The Treaty addresses four areas:

a. non-discriminatory conditions for trade and provisions on reliable cross-border energy transit;
b. protection of direct foreign investment and protection against key non-commercial risk;
c. a dispute resolution system between participating states and between investors and host states; and
d. the promotion of energy efficiency.

The Energy Community is an international organisation joining the European Union with a number of countries from the South East Europe and Black Sea regions, with the primary aim of extending the European acquis communautaire on energy, environment, competition and renewables to the parties. The Energy Community Treaty additionally sets up a regulatory mechanism for the regional network energy markets. It is worth noting that

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1 Charles Morrison, Natasha Luther-Jones and Andreas Gunst are partners at DLA Piper International.
the implementation of the European internal energy market in contracting states is a measure that facilitates potential membership of the European Union, as demonstrated by Bulgaria and Romania in 2007 and Croatia in 2013.

The Paris Agreement has been ratified by 148 out of 197 parties to the United Nations Framework Convention on Climate Change, reaching its threshold to enter into force in October 2016. It sets ambitious targets for the parties to mitigate and adapt to climate change and contribute to the decarbonisation of the global economy, and imposes obligations upon all European Union Member States.

The cornerstone of the European energy policy is the internal energy market, which aims to achieve three primary objectives: affordable and competitively priced energy, environmental sustainability and energy security. In its achievement, European Union competition law plays an essential and complementary role, with free market provisions being enforced in coordination with energy regulators.

In its adoption of ‘A Framework Strategy for a Resilient Energy Union with a Forward-Looking Climate Change Policy’ in February 2015, the Commission has set itself the priority of establishing the Energy Union, a grand strategy for European energy policy. It sets out five key ‘dimensions’:

a. energy security, solidarity and trust;
b. a fully integrated European energy market;
c. energy efficiency contributing to moderation of demand;
d. decarbonising the economy; and
e. research, innovation and competitiveness.

The Energy Union goes beyond the concept of the internal energy market in that it introduces an element of foreign policy, addressing security and supply risks in the European neighbourhood, and in doing so seeking to create a unified European approach to importing energy. This strategy develops the concept of solidarity in matters of energy supply as introduced by the Treaty of Lisbon.

The next step in the development of the Energy Union is covering the period of 2021 to 2030. In November 2016, the European Commission published the proposal for the Clean Energy for All Europeans package (formerly known as the Winter Package), a legislative package that largely proposes to update the Third Energy Package and other key EU environmental legislation. The proposals must, however, pass through the ordinary legislative procedure and may undergo material changes prior to their enactment. At the time of writing, the Energy Performance in Buildings Directive, recast Renewable Energy Directive, amendment to the Energy Efficiency Directive, and new Regulation on the Governance of the Energy Union have been enacted, and the recast Electricity Directive, recast Electricity Access Regulation, recast ACER Regulation and a new Regulation on Electricity Sector Risk-Preparedness are expected to be enacted in mid-2019.

It is clear that there is a substantial body of legislation regulating the European energy markets. For the purpose of this chapter, the main provisions of key secondary energy legislation will be presented.

II EUROPEAN ELECTRICITY AND GAS REGULATORY SYSTEM

The Third Energy Package, which is due to be amended and expanded by the Clean Energy Package, is a legislative package comprised of three regulations and two directives designed
to create the internal market for electricity and gas. These are the ACER Regulation, the Electricitic Directive and Gas Directive, and the Electricity Access Regulation and Gas Access Regulation. The regulatory system for the European energy markets is effectively divided into the national and European Union level.

On the national level, the Electricity and Gas Directives require Member States to designate national regulatory authorities (NRAs), independent bodies that are primarily responsible for setting national transmission or distribution tariffs, cooperating with other NRAs on cross-border issues, monitoring the investment plans of national transmission system operators (TSOs), and ensuring the transparency of consumption data for consumers.

The ACER Regulation provides for the establishment and legal status of the Agency for the Cooperation of National Regulators (ACER), a European forum for the cooperation of NRAs. It defines its tasks, in particular those regarding NRAs, cross-border infrastructure access conditions and operational security, obligations on consultations and transparency, monitoring and reporting obligations on the electricity and natural gas sectors, organisational structure and its budget.

The Commission proposal for a recast ACER Regulation includes provisions on new tasks and restructuring to reflect the enhanced role ACER is to play in the Energy Union, as well as allowing ACER to establish local offices in Member States.

ACER and the NRAs form the core of the European electricity and gas regulation system and are supported by a number of other bodies as described below.

The Commission proposal for a Regulation on the Governance of the Energy Union centralises governance and reporting provisions for the entire EU energy sector, including provisions on integrated national energy and climate plans; long-term low emission strategies; Commission assessment of national plans and EU target achievement; national and EU systems on greenhouse gas emissions and removals by sinks; and cooperation and support between Member States and the EU.

III ELECTRICITY

i Electricity Directive

The Electricity Directive focuses specifically on establishing the European internal market for electricity. In particular, it sets out public service obligations for electricity undertakings and customer protection obligations, the monitoring of security of supply by Member States, technical rules and the promotion of regional cooperation of Member States and NRAs. As regards new generation capacity, it establishes an authorisation procedure and a tendering option.

Furthermore, transmission systems and TSOs must be unbundled; however, Member States may instead opt to designate an independent system operator. Unbundling provisions

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5 Regulation (EC) No. 714/2009 on conditions for access to the network for cross-border exchanges in electricity.
include the designation and certification of TSOs by NRAs, their tasks, ownership unbundling, dispatching and balancing, and confidentiality, as well as defining decision-making powers of TSOs regarding the connection of new power plants.

Distribution system operators (DSOs) must additionally be unbundled, with the Directive providing for their designation by the Member States, their tasks and confidentiality obligations, as well as provisions on optional closed distribution systems. For both TSOs and DSOs, the unbundling process includes the transparency of their accounts to Member States or any designated authority.

The Directive further regulates transmission and distribution system access, notably on the freedom of third-party access, market opening and reciprocity, and direct lines to all eligible customers.

As discussed above, the Electricity Directive establishes NRAs, including their objectives, duties and organisational structure, and includes provisions on retail markets, as well as safeguard measures in response to a sudden energy market crisis, and the non-discriminatory nature of the Directive’s implementation.

The Commission proposal for the recast Electricity Directive includes provisions on further developing market-based pricing with an option for public intervention for vulnerable consumers, the expansion of consumer rights, the expansion of the tasks of NRAs regarding regional cooperation on cross-border matters, the clarification of the roles of TSOs regarding energy storage and regional coordination centres, and the clarification of the role of DSOs regarding energy storage and recharging points for electric vehicles. The recast Electricity Directive is expected to be adopted by the Council by mid-2019 and will take effect as of 2021.

ii Electricity Access Regulation

The Electricity Directive is coupled with the Electricity Access Regulation, which establishes the European Network of Transport System Operators for Electricity (ENTSO-E), a European forum for the cooperation of TSOs, which is tasked with monitoring national TSOs and their EU-wide network development plans. The Regulation designates tasks for ENTSO-E and monitoring obligations for ACER.

The Regulation furthermore establishes network codes (see Section III.iii), regulates network access charges, the provision of information by TSOs, general principles of congestion management and special provisions on new interconnectors.

The Commission proposal for the recast Energy Access Regulation includes provisions on core market principles, in particular that electricity prices are formed based on demand and supply and forbidding caps or floors on wholesale prices; the introduction of rules on balancing markets; the non-discriminatory and market basis of power generation and demand-response dispatching; the introduction of a definition of bidding zone borders; and the introduction of a European cooperation platform for DSOs. The recast Electricity Access Regulation is expected to be adopted by the Council by mid-2019 and will take effect as of 2021.
iii Network codes

Network codes are technical rules designed to address key priorities specified by the European Commission. These aim to develop and harmonise specific aspects of the European energy networks, including capacity allocation, balancing supply and demand, requirements of generators and transmission networks, and security of supply.

Currently, 10 electricity network codes have been specified, which are grouped into three categories:

a. connection codes, which set requirements for the connection of both generators and large customers to the transmission grids;
b. operational codes, designed to regulate the operation of the transmission systems and the security of supply, and to ensure that supply and demand of electricity within and between transmission systems is balanced; and
c. market codes, which encourage a transparent and competitive pan-European marketplace for electricity and capacity in all timescales, and stimulate generator diversification and infrastructure optimisation.

At the time of writing, eight and thereby all of the originally planned electricity network codes have entered into force. The network code on capacity allocation and congestion management (CACM) sets out methods for allocating capacity in day-ahead and intra-day timescales, and designates nominated electricity market operators as coupling operators, and sets out their tasks as well as tasks for TSOs relating to single day-ahead and intraday coupling. The CACM includes detailed provisions on terms, conditions and methodologies on capacity allocation and congestion income distribution.

The network code on forward capacity allocation sets out methods for allocating capacity in the forward markets, and aims to promote effective long-term cross-zonal trade with long-term cross-zonal hedging products for market participants, optimise the calculation and allocation of long-term cross-zonal capacity, provide non-discriminatory access to long-term cross-zonal capacity, ensure fair and non-discriminatory treatment of TSOs and market participants, and enhance the transparency and reliability of information.

The network code on electricity balancing sets out provisions on terms and conditions or methodologies of TSOs and their approval; roles and responsibilities of TSOs in the electricity balancing market; the establishment of European platforms for the exchange of balancing energy from (1) replacement reserves, frequency restoration reserves with manual activation and (2) frequency restoration reserves with automatic activation; the establishment

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8 As established for the electricity market by the Electricity Access Regulation.
9 Network codes are initiated as non-binding ‘framework guidelines’ set out by ACER, outlining the aims and content to be achieved. Through consultation with stakeholders and the public, ENTSO-E drafts network codes based on these framework guidelines. These are subsequently evaluated by ACER to ensure their adherence to the framework guidelines. The draft network codes are then accepted through the process of comitology, and are finally published by the European Commission, commonly as binding regulations.
10 Commission Regulation (EU) 2015/1222 establishing a guideline on capacity allocation and congestion management.
11 Commission Regulation (EU) 2016/1719 establishing a guideline on forward capacity allocation.
of a European platform for the imbalance netting process; the procurement of balancing services; cross-zonal capacity for balancing services, balancing settlement and balancing algorithms; and reporting obligations.

The network code on emergency and restoration\(^{13}\) sets out provisions on regional coordination; the development of a system defence plan and a restoration plan; the development of rules and procedures for the suspension and restoration of market activities; information exchange between TSOs; and compliance testing with obligations under the code.

The network code on demand connection\(^{14}\) sets out requirements for the grid connection of transmission-connected demand facilities, transmission-connected distribution facilities, distribution systems and demand units as used by a demand facility or closed distribution system to provide demand-response services.

The network code on high voltage direct current connections\(^{15}\) sets out requirements for long-distance direct current connections, links between different synchronous areas and direct current-connected power park modules, such as offshore wind farms.

The network code on requirements for generators\(^{16}\) provides requirements for newly constructed generators, as well as notification procedures and compliance provisions.

The network code on system operation\(^{17}\) sets out provisions on operational security requirements; data exchange between different market participants; compliance with SO provisions; the development of training programmes on and certification of real-time system operation, operational planning, operational security analysis, outage coordination and control area adequacy analysis; the availability and provision of ancillary services; scheduling; the implementation and operation of an ENTSO-E operational planning data environment; and load-frequency control and reserves.

### iv Proposal for risk preparedness

The Commission proposal for a Regulation on Risk-Preparedness in the Electricity Sector proposes measures for risk assessments and risk preparedness, as well as the management of any electricity crisis situations in the Union, in particular setting out methodologies to assess electricity security of supply and to identify crisis situations on the level of both Member States and their regions. This proposal is expected to be adopted by the Council in mid-2019.

### IV NATURAL GAS

#### i Gas Directive

The Gas Directive is the natural gas counterpart to the Electricity Directive, setting up a similar regulatory structure for the internal market for natural gas. In doing so, it sets

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\(^{13}\) Commission Regulation (EU) 2017/2196 establishing a network code on emergency and restoration.

\(^{14}\) Commission Regulation (EU) 2016/1388 establishing a network code on demand connection.

\(^{15}\) Commission Regulation (EU) 2016/1447 establishing a network code on requirements for grid connection of high-voltage direct current systems and direct current-connected power park modules.

\(^{16}\) Commission Regulation (EU) 2016/631 establishing a network code on requirements for grid connection of generators.

\(^{17}\) Commission Regulation (EU) 2017/1485 establishing a guideline on electricity transmission system operation.
out public service and customer protection obligations for gas undertakings, authorisation procedures, the monitoring of security of gas supply, regional solidarity, the promotion of regional cooperation, and technical rules.

The Directive includes provisions on the unbundling of transmission systems and TSOs, their designation and certification by NRAs, their certification in relation to third countries, the unbundling of transmission system owners and storage system operators, and the designation of storage and LNG system operators, as well as duties for these entities. As an alternative to unbundling, Member States may opt to establish independent system operators.

DSOs must be unbundled, with the Directive regulating the designation of DSOs, their tasks, and the option for Member States to designate closed distribution systems.

The Directive further regulates system access, specifically third-party access, access to storage, access to upstream pipeline networks, refusal of access, new infrastructure, market opening and reciprocity, and the possible designation of direct lines. It includes provisions on retail markets, safeguard measures and the level playing field.

The Directive requires Member States to establish NRAs, and sets out their objectives, duties and organisational structures.

The Directive is to be amended in due course following a proposal of the European Commission in November 2017. This amendment will extend the rules set out under the current Gas Directive to gas transmission infrastructure running between Member States and third countries.

ii Gas Access Regulation

The Gas Access Regulation establishes the European Network of Transmission System Operators for Gas (ENTSOG), the sister organisation of ENTSO-E, which cooperates in the same manner with ACER.

As with the Electricity Access Regulation, the Gas Access Regulation establishes network codes (see Section IV.iii). In addition, it establishes the free and non-discriminatory access of third parties to gas transmission networks on the European natural gas markets, thereby enforcing the principle of free competition.

The Regulation in particular provides for the transparency of tariffs and calculation methodologies for access to networks, third-party access services, the principles of capacity-allocation mechanisms and congestion management procedures, transparency requirements, balancing rules and imbalance charges, trading of capacity rights, guidelines on the minimum degree of harmonisation, compliance of regulatory authorities and reporting obligations from Member States to the Commission.

iii Network codes

Network codes for natural gas follow the same principles as those for electricity, and have near-identical key priorities. At the time of writing, five gas network codes have been adopted.

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18 As established for the gas market by the Gas Access Regulation.
19 The development process for natural gas network codes is identical to that for electricity; however, ENTSOG is tasked with performing the stakeholder consultations and drafting of the network code based on the framework guidelines.
The network code on capacity allocation mechanisms (CAM)\textsuperscript{20} was recast in March 2017, updating the previous regulation to include the offer of incremental capacity and removing provisions on tariffs that have been included in a separate network code. The CAM regulates the principles of cooperation between TSOs in adjacent EU Member States, and the allocation of firm capacity. Allocation provisions are divided into allocation methodology, standard capacity products and capacity auction systems over different time frames. It furthermore regulates the bundling of cross-border capacity, incremental capacity, interruptible capacity and capacity booking platforms.

The network code on gas balancing in transmission networks\textsuperscript{21} sets out detailed provisions for a gas balancing system, trade notifications and allocations, operational balancing procedures, and on nomination and re-nomination procedures. The balancing procedures include provisions on short-term standardised products and the establishment of a trading platform for their procurement, as well as incentives for TSOs to undertake efficient balancing actions.

The network code on Interoperability and Data Exchange (INT)\textsuperscript{22} regulates interconnection agreements, providing that adjacent TSOs mutually agree upon rules for flow control, measurement principles for gas quantity and quality, rules for gas quantity allocation, and communication procedures in the case of exceptional events. It further provides for a dispute resolution system, and sets out a common set of units, as well as provisions for gas quality and odorisation.

The network code on tariff harmonisation\textsuperscript{23} aims to homogenise gas transmission tariffs within the European Union, promoting fair and objective tariffs, providing methodologies on reference prices, reserve prices, clearing price and payable price, provisions on reconciliation of revenue, pricing of bundled capacity and capacity at virtual interconnection points, consultation and publication requirements, and tariff principles for incremental capacity.

Congestion management procedures\textsuperscript{24} are fundamentally guidelines addressing third-party access services concerning TSOs, the principles of capacity-allocation mechanisms and congestion management procedures, and their application in the event of contractual congestion, as well as setting out the technical information necessary for network users to gain effective access to the system.

Remaining priority areas include network security and reliability rules, network connection rules, third-party access rules, data exchange and settlement rules, emergency operational procedures and transparency. These are currently under consideration by ACER.

\textsuperscript{20} Commission Regulation (EU) 2017/459 establishing a network code on capacity allocation mechanisms in gas transmission systems.
\textsuperscript{22} Commission Regulation (EU) 2015/703 establishing a network code on interoperability and data exchange rules.
\textsuperscript{23} Commission Regulation (EU) 2017/460 establishing a network code on harmonised transmission tariff structures for gas.
iv Gas security of supply regulation

The Gas Security of Supply Regulation 25 aims to prevent a disruption of natural gas supply to the European Union and to ensure a coordinated response if necessary. Its fundamental principle is that security of gas supply is the shared responsibility of natural gas undertakings, Member States and the Commission.

It provides for the establishment of a Gas Coordination Group; the development of a robust infrastructure network across the European Union; the development of a gas supply standard to ensure that vulnerable consumers have gas supply under certain extreme circumstances; the performance of a regular risk assessment by ENTSOG and coordinators of regional cooperation Member State groups; the establishment of preventive action plans and emergency plans, different supply crisis levels, regional and Union emergency responses; the solidarity principle whereby in a severe crisis neighbouring Member States are to help ensure that gas supplies to households and essential social services receive a continued supply of gas; information exchange, handling of confidential information by various market participants and authorities; and cooperation with the Energy Community Contracting Parties.

V PETROLEUM

i Oil and Gas Licensing Directive

The Oil and Gas Licensing Directive 26 sets out common rules that aim to ensure competitive and non-discriminatory access to third parties to prospect, explore and produce hydrocarbons within the territories of the Member States.

Authorisations must be granted in a transparent and non-discriminatory manner to all interested parties. The evaluation of authorisations is based on criteria relating to the technical and financial capabilities of the applicant and the manner in which it proposes to exploit the area.

The boundaries of authorisation areas must be determined in such a way that the entity can act in the most efficient manner from an economic and technical point of view. This is intended to encourage the most efficient means of exploitation, as in some cases several entities can do so more effectively than single entities.

Member States are obliged to submit information pertaining to the authorisation to be published in the Official Journal of the European Union. This information includes the duration of the authorisation, the specific area, and selection criteria. Furthermore, Member States are obliged to submit an annual report on the areas opened, authorisations granted, details of entities holding the authorisations and information regarding the reserves available in their territory.


26 Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons.
ii Oil Stockholding Directive

The stocks of crude oil and petroleum products directive\(^{27}\) sets out rules to mitigate an oil supply crisis in the European Union. The Directive sets out obligations for Member States to maintain emergency stocks, including a methodology for calculating stock levels, and the obligation to ensure the availability and accessibility of stocks. Member States must maintain a register of emergency stocks and submit an annual report to the Commission. Member States may set up a central stockholding entity to support it in these obligations.

The Directive imposes regulations on economic operators, and permits Member States to maintain and manage a minimum level of specific oil stocks, providing methodologies to calculate summaries of stocks. Furthermore the Directive sets up a coordination group for oil and petroleum products, permits the Commission to review emergency preparedness and stockholding, and requires that Member States have emergency procedures in place in case of a major supply disruption.

VI TEN-E REGULATION

The trans-European energy infrastructure regulation (TEN-E)\(^{28}\) complements the aims of the Third Energy Package, establishing the concept of projects of common interest (PCIs). These are infrastructure projects that would significantly contribute to the development of the internal market and the achievement of the European Commission's 2020 goals, namely a 20 per cent cut in greenhouse gas emissions (from 1990 levels), achieving 20 per cent of European Union energy from renewables, and a 20 per cent improvement in energy efficiency by 2020.

TEN-E regulates in particular the selection, implementation and monitoring of PCIs, as well as permit granting procedures, public participation, the regulatory treatment of PCIs, financing eligibility criteria and guidance for the awards criteria of financial assistance.

PCIs may benefit in a number of ways, including through accelerated and more efficient permit granting procedures; improved regulatory treatment on the national level; streamlined environmental assessment procedures; increased public participation via consultation; and access to grants from the Connecting Europe Facility.

A list of PCIs is established by the European Commission every two years. In November 2017, the third PCI list was published.\(^{29}\) It includes 173 projects, of which 110 are electricity and smart grids projects, 53 are gas projects and six are oil projects. A total of €1.6 billion is available in grants to PCI projects for works and studies, and receiving PCI status furthermore increases the attractiveness to external investors.

An applicant project must meet a series of criteria to be considered a PCI, in that it has to have significant benefits for at least two Member States; contribute to market integration and further competition; enhance security of supply for the European Union; and reduce CO\(_2\) emissions.

\(^{27}\) Directive 2009/119/EC imposing an obligation on Member States to maintain minimum stocks of crude oil or petroleum products.


TEN-E grants the Commission the ability to nominate PCIs by means of delegated acts, and sets out the conditions of its exercise. TEN-E further sets out obligations on reporting and evaluation of PCIs as well as information and publicity obligations.

**VII RENEWABLE ENERGY DIRECTIVE**

The Renewable Energy Directive (RED)\(^{30}\) is a key directive for the European Union’s commitment to renewable energy generation and consumption, setting out the specific aim of fulfilling at least 20 per cent of its total energy needs with renewable source energy by 2020, and a mandatory target of a 10 per cent share of energy from renewable sources in the transportation sectors of Member States by 2020.

The Directive requires Member States to set mandatory national overall targets and measures for the use of energy from renewable sources, as well as to adopt national renewable energy action plans. In order to achieve these targets, the Directive provides for statistical transfers, joint projects between Member States or third countries, and joint support schemes between Member States.

Member States are required to provide information and training on support measures and details on the benefits, cost and energy efficiency of renewable source energy to consumers, builders, architects and equipment suppliers.

One important aspect of the Directive is the establishment of guarantees of origin of electricity, heating and cooling produced from renewable energy sources, which is a system to ensure that the origin of electricity produced from renewable energy sources can be guaranteed.

The Directive furthermore regulates the access to and operation of the transmission and distribution grids, as well as sustainability criteria for biofuels and bioliquids and verification of their compliance, and specific provisions related to energy from renewable sources in transport. The Commission is additionally required to monitor and report the origin and impact of biofuels.

Member States are required to regularly report the progress of the promotion and use of renewable source energy, and the Commission is required to establish an online public transparency platform to facilitate and promote cooperation between Member States.

In December 2018, the recast Renewable Energy Directive (REDII)\(^{31}\) entered into force, and it is to be implemented by Member States as of 1 July 2021, upon which date RED is to be repealed. REDII includes provisions on a minimum target of 32 per cent for the share of energy from renewable sources in the Union’s gross final consumption of energy in 2030, the opening up of support schemes to projects in other Member States (permitting Member States to support renewable generators in other Member States), new qualifications for accounting for guarantees of origin issued to supported generators, extending the use of guarantees of origin to non-renewable projects, and the right of consumers generating their own electricity (known as renewables self-consumers) to sell any excess while retaining their rights as consumers.

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\(^{30}\) Directive 2009/28/EC on the promotion of the use of energy from renewable sources.

\(^{31}\) Directive (EU) 2018/2001 on the promotion of the use of energy from renewable sources.
VIII ENERGY EFFICIENCY

i  Energy Efficiency Directive

The Energy Efficiency Directive\(^{32}\) aims to promote energy efficiency across the European Union in order to meet the European Union 2020 goal of 20 per cent target on energy efficiency, thereby removing barriers that limit efficiency in the supply and use of energy.

The Directive requires Member States to set national energy efficiency targets and a strategy to mobilise investment for improving the energy efficiency of buildings, whereby public bodies are to set an exemplary role. It regulates public procurement with regard to energy efficiency, requires Member States to set up energy efficiency obligation schemes and sets out a number of consumer obligations.

Member States are required to encourage the use of energy audits and energy management systems for final consumers; provide final consumers with meters, cost-free access to metering and billing information and information on energy; and implement a consumer empowerment programme.

Member States are additionally required to perform a comprehensive assessment of the potential for the application of high-efficiency cogeneration and efficient district heating and cooling, and to ensure that, in the performance of their duties, NRAs take account of energy efficiency measures. The Directive provides for a system of qualification, accreditation and certification schemes for providers of energy services, energy audits, energy managers and installers of energy-related building elements should the Member State consider itself not to have the required technical competence.

Furthermore, Member States are required to promote energy services markets for SMEs, and are permitted to set up an energy efficiency national fund and other financing and technical support to increase energy efficiency in different sectors.

In December 2018, the amended Energy Efficiency Directive\(^{33}\) entered force, and the amendments to the current Energy Efficiency Directive are to be made by Member States by 25 June 2020 (with some provisions to be implemented by 25 October 2020). The amendment sets out a binding 32.5 per cent minimum energy efficiency target for 2030, building on that of 20 per cent for 2020, updates the energy savings obligation for Member States, and extends consumer rights in particular regarding billing and energy consumption information through smart metering systems.

ii  Energy Performance in Buildings Directive

The Energy Performance in Buildings\(^{34}\) aims to promote the improvement of the energy efficiency of buildings within the European Union.

The Directive sets out a common general framework to develop a methodology to calculate the energy performance of buildings and building units, minimum requirements on the energy performance of new and existing buildings, a national plan for increasing the number of nearly zero-energy buildings, rules on energy certification of buildings or building units, and on independent control systems for energy performance certificates and inspection reports.

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In December 2018, the amended Energy Performance in Buildings Directive entered force, and the amendments are to be made by Member States by 10 March 2020. The amended Directive introduces an obligation for Member States to establish a long-term renovation strategy and develops requirements for residential and non-residential buildings, such as installing recharging points for electric vehicles, and details on heating systems and air-conditioning systems.

IX  DECARBONISATION

i  Emissions Trading Directive

The European greenhouse gas emissions allowance trading scheme (the Emissions Trading Scheme (ETS)) was established by the Emissions Trading Directive with the aim of significantly reducing greenhouse gas emissions through a cap-and-trade scheme.

The Emissions Trading Directive notably regulates greenhouse gas emissions permits and their application procedure; notification obligations for installation operators; the development of a national allocation plan; allocation methods for allowances; the transfer, surrender and cancellation of allowances throughout the European Union; the validity of allowances; guidelines for monitoring and reporting of emissions; and verification of reports submitted by operators. Allowance allocation decisions are to be made available to the public, and Member States must establish allowance registries, and they are further subject to reporting obligations. The Commission is required to designate a central administrator that is to maintain an independent transaction log, recording the issue, transfer and cancellation of allowances.

The Emissions Trading Directive is supported by additional legislation, such as the Registry Regulation, which sets up the registries system and regulates the creation, deletion and suspension of accounts, verification of emissions and compliance, the performance of transactions, permissible allowances, trading mechanisms, general technical requirements, and links with other greenhouse gas emission trading schemes.

36 Directive 2003/87/EC establishing a scheme for greenhouse gas emission allowance trading within the Community.
X THE CARBON CAPTURE AND STORAGE DIRECTIVE

The Carbon Capture and Storage (CCS) Directive provides a legal framework for the environmentally safe geological storage of carbon dioxide, regulating the selection of storage sites, conditions on exploration permits and storage permits, and operation obligations. These operating obligations include the composition of carbon dioxide streams and their acceptance procedure; the monitoring of storage facilities; reporting obligations of the storage operator; inspections of the facilities; closure and post-closure obligations; the provision of financial security by operators for storage permits; and a financial mechanism for the competent authority.

This competent authority is to be designated by the Member State to fulfil its duties under the Directive, as well as to facilitate trans-boundary cooperation and maintain a registry of permits and closed storage sites.

The Directive further regulates third-party access to transport network and storage sites, and requires Member States to provide information to the public regarding storage operations as well as regular updates to the Commission on the implementation of the Directive.

XI ENERGY MARKETS

Following the global financial crisis of 2008/09, the European Union has adopted a number of legislative instruments to stabilise the financial markets, limit price volatility of commodities and ensure that markets have sufficient capital. It is not the aim of this chapter to discuss financial regulations; however, while not energy-specific, it should be kept in mind that the energy market is affected by European financial markets legislation.

Along with the Third Energy Package and REMIT, this legislation has introduced additional obligations for energy markets including reporting obligations, transparency requirements, the treatment of certain types of energy or emissions allowances as financial instruments or derivatives, organisational requirements for markets, the introduction of new trading venues, the mandatory use of regulated markets for certain products and a clearing obligation for certain trades.

XII FUTURE DEVELOPMENTS

Two main external factors are likely to direct European Union energy policy in the future: the need to diversify and secure energy supply, and the Paris Agreement (including its implementation through successive conferences of the parties to the United Nations

European Union Framework Convention on Climate Change. The Juncker Commission has made significant commitments to the Energy Union, which promotes the diversification of energy sources and the tightening up of bilateral agreements between Member States and third states.

The European Union has already set mandatory targets to increase the share of renewable source energy in the European energy mix, which are in line with the target of the Paris Agreement. Following the ratification of the Paris Agreement, the Clean Energy for All Europeans package would appear to make an increased commitment from the European Union and its Member States to decarbonise the economy. Individual acts under the Clean Energy for All Europeans package are currently passing through the ordinary legislative procedure, and subject to further negotiation, the acts are expected to be enacted during the second half of 2018; however, the entry into force dates for these acts as well as the transposition deadlines of the directives remain unclear.

On 29 March 2017, the United Kingdom triggered Article 50 of the TEU following the result of the Brexit referendum in June 2016. This started a two-year negotiation window for the EU and UK to agree on the terms of UK withdrawal and potentially the EU–UK cooperation mechanism. On 19 March 2018, the European Union and UK made a significant step in the Brexit negotiations, agreeing upon the ‘Draft Agreement on the withdrawal of the United Kingdom of Great Britain and Northern Ireland from the European Union and the European Atomic Energy Community’ (the Draft Agreement). While the Draft Agreement is still subject to negotiation and the acceptance of the UK Parliament, it provides for a transition period until 31 December 2020. Under the Draft Agreement, the UK would remain subject to EU law and would remain part of the internal market; however, the UK would cease to be involved in the EU legislative procedure unless invited by the Member States.

Of possible relevance to the energy sector, the Draft Agreement provides on a high level for the movement of goods placed on the market prior to the end of the transition period, and on ongoing customs procedures. Neither the Draft Resolution nor the current status of negotiations, however, provide any clarity as to the impact of Brexit on the energy sector. It is unclear whether the UK government will continue with its intention of pursuing a ‘hard’ Brexit, whereby membership of the European Economic Area Agreement would be excluded, and whether this may take the form of simply withdrawing from the EU without any withdrawal or cooperation agreement (i.e., the future relationship between the EU and UK being governed by World Trade Organization rules).

Notwithstanding the effects of Brexit on the UK energy sector, the regulatory landscape in the EU is likely to remain largely unchanged; however, certain issues may arise as part of the proceedings. These may include the adaptation of the ETS to account for the withdrawal of the EU’s second-largest emitter, as well as issues involving connection to the newly established UK energy sector. The Brexit negotiations will doubtless be complex, and the exact nature of any possible effects on the EU energy sector remains unclear; however, based on the Draft Agreement, it would appear that these effects may be delayed until 31 December 2020.

I OVERVIEW

Energy regulation and market control has become a highly politicised issue in Australia. So much so that Australia’s previous Prime Minister, Malcolm Turnbull, was voted out of this position mid-term by his own party largely due to an inability to pass a coherent energy policy through Federal Parliament. With a federal election announced for 18 May 2019, we expect that energy policy will continue to be a political football in the near term, and can only hope that the next Commonwealth government of Australia is able to deliver the holy grail of energy policy that delivers:

- reduced electricity costs for households and industry (which are currently being crippled by souring electricity prices);
- reduced carbon emissions so that Australia can meet its commitment at the Paris climate change conference to reduce emissions by to 26–28 per cent on 2005 levels by 2030; and
- stability and reliability of supply so that consumers can be confident of uninterrupted supply, including during peak demand periods.

Since 2007, Australia has seen a parade of different energy policies at a federal level, with not one staying in place for more than a couple of years. This has left the electricity generation, transmission and retail industry in limbo, and no doubt has been the driver behind the lack of investment in new generation facilities, which has in turn driven up electricity prices and provided no coherent and integrated pathway for investment in grid upgrades and carbon reduction schemes.

In many ways the chaos at a federal level has left state governments and industry to go it alone. Therefore, we have seen state governments each introduce their own different energy policies designed to address the three issues noted above and industry making investment decisions based predominantly on those market drivers that are divorced from the influence of federal policy.
Given the differing energy regulation and markets around Australia, this chapter will summarise the following in each state of Australia and look at possible policy and market developments:

a regulatory framework;
b transmission and distribution networks;
c retail markets; and
d policies and developments.

II REGULATION

i The regulators

The Australian Energy Market Operator (AEMO) is the industry-funded organisation that oversees the functioning of the National Electricity Market (NEM) in the states of Queensland, New South Wales, the Australian Capital Territory, Victoria, Tasmania and South Australia and the Wholesale Electricity Market (WEM) in Western Australia.

The NEM is regulated pursuant to the National Electricity Rules and National Electricity Law created by the Council of Australian Governments (COAG). The WEM is regulated pursuant to the WEM Rules and related WEM Market Procedures. There is a proposal for Western Australia to also be regulated by the National Electricity Rules and National Electricity Law,\(^4\) so that Australia can have national uniform regulations; however, this proposal has stalled pending certain integration issues being resolved.

In relation to the NEM, the Australian Energy Regulator (AER) oversees economic regulation and compliance with the National Electricity Rules and is accountable to the Commonwealth Government as an arm of the Australian Competition and Consumer Commission. The Australian Energy Market Commission (AEMC) works alongside the AER and AEMO to determine the policy and governance structures that support Australia’s energy markets. The AEMC is responsible to COAG. To coordinate the operation of AEMO, AER and the AEMC in overseeing energy policy and regulation relating to the NEM, these organisations also come together as members of the Market Bodies Forum, which reports to COAG in relation to matter requiring action on the part of these organisations.\(^5\)

In relation to the WEM, the Economic Regulation Authority (ERA) is established under the Economic Regulation Authority Act 2003 (WA) as an independent statutory authority designed to oversee the energy industry in WA and ensure that all parties abide by the relevant regulations. It issues licences to providers of various sources of energy, including electricity. In addition, the ERA monitors and publicly reports on industry performance, including the WEM; taking enforcement action when required. It also has authority through various codes\(^6\) to approve contracts and service standards that protect residential and small business electricity, gas and water customers and assess the performance of utilities in relation to the treatment of customers experiencing financial hardship.

The Clean Energy Regulator Act 2011 (Cth) established the CER, a non-corporate Commonwealth entity for the purposes of the Public Governance, Performance and

\(^4\) National Electricity (Western Australia) Bill 2016 Explanatory Memorandum.
Accountability Act 2013 (Cth). As an independent statutory authority, the CER is comprised of the chair and members, who set the ‘strategic direction’ for the agency’s administration of its regulatory schemes. The role of the CER is to administer climate change law legislated by the Australian government to measure, manage, reduce or offset Australia’s carbon emissions. Accordingly, the CER has administrative responsibilities for the National Greenhouse and Energy Reporting Scheme (NGERS) under the National Greenhouse and Energy Reporting Act 2007, the Emissions Reduction Fund (ERF) under the Carbon Credits (Carbon Farming Initiative) Act 2011, the Renewable Energy Target (RET) under the Renewable Energy (Electricity) Act 2000, and the Australian National Registry of Emissions Units under the Australian National Registry of Emissions Units Act 2011.

ii Regulated activities

NEM

The National Electricity Law and associated National Electricity Rules regulate market activities, and the National Energy Retail Law and associated National Energy Retail Rules regulate retail activities. A National Energy Customer Framework (NECF) has also been adopted in all states participating in the NEM other than Victoria. The NECF is effectively a package of reforms to the National Energy Retail Law that implement the framework together with the National Energy Retail Regulations 2012 and the National Energy Retail Rules. The extent to which the NECF has been adopted in each state is slightly different; therefore, it is necessary to consult the relevant state and territory laws to see which provisions have been amended.

The following key activities are regulated within the NEM by the AER:

a at a wholesale level, participant bidding, dispatch and prices, network constraints and outages and forecasting in relation to demand and capacity are monitored by the AER to ensure there is no misuse of market power;

b in relation to networks, the AER sets a maximum revenue that network service providers can earn based on proposals submitted by those providers detailing their required revenues based on customer demand, their cost base, age depreciation of their infrastructure and maintenance measures required to maintain network safety and stability; and

c at a retail level, the AER provides a price comparison guide on their website (applicable to those jurisdictions that have adopted the National Energy Retail Law) to provide customers with visibility of costs and charges across the different providers. Thus, the AER seeks to reduce prices in the market through aiding competitive tension between


8 Note 8, above.


providers, rather than setting retail energy prices. The AER also authorises new retail providers and enforces compliance with the National Energy Retail Law, Rules and Regulations.\textsuperscript{11}

**WEM**

Pursuant to the Electricity Industry Act 2004 (WA) (the EI Act), there is a legal requirement to obtain different classifications of electricity licences from the ERA where you intend to:

\begin{itemize}
  \item[a] construct or operate generating works;
  \item[b] construct or operate a transmission system of a voltage of 66kV or higher;
  \item[c] construct or operate a distribution system of a voltage of less than 66kV;
  \item[d] sell electricity to customers; or
  \item[e] construct or operate any combination of generation, transmission, distribution and retail activities for the purpose of supplying electricity to customers other than through the SWIS.\textsuperscript{12}
\end{itemize}

However, there are also certain activities in the electricity industry that fall outside the scope of the licensing requirements under the EI Act and do not require a licence; these include:

\begin{itemize}
  \item[a] self-supply: where the generating works, transmission system or distribution system is to be used solely for the supply of electricity for consumption by the person who owns, controls or operates the works or system or a related body corporate of that person; and
  \item[b] where the sale of electricity is to a person who is not the end-use customer; for example, a generator who sells electricity solely to retailers is not required to hold an electricity retail licence.
\end{itemize}

**iii Ownership and market access restrictions**

**NEM**

The NEM is described as an open access transmission system whereby generators apply to the network service provider with an access proposal and the network service provider makes an offer to connect to generator’s whose load meets network requirements and will enhance the reliability of supply on the network. Network service providers must invest in network upgrades on an as-needed basis to meet their statutory obligations to maintain reliability of supply to end customers. Generators have a right to connection, but not to being able to export all their output to the system and therefore pay a fix connection charge. Customers then bear the cost of network usage by paying variable charges linked to demand. Network service providers can also invest in network upgrades along their region of the network to reduce network congestion, provided this passes a cost benefit test relating to the benefit to market participants and consumers of the proposed investment. The AER also creates incentive schemes to promote investment by network service providers in targeted areas of the network to meet its network planning objectives.\textsuperscript{13}

\textsuperscript{12} Electricity Industry Act 2004 (WA) Section 4; Economic Regulation Authority, Licence Application Guidelines and Form (November 2016), 2.
\textsuperscript{13} Factsheet: How transmission frameworks work in the NEM (18 July 2017).
The Electricity Networks Access Code 2004 (the Access Code) is established under the EI Act and provides the framework for the independent regulation of certain electricity networks in WA. The objective of the Access Code is to promote efficient investment in, and operation and use of, networks and services of networks in WA and to promote competition in electricity retail and wholesale markets. The Access Code allows a ‘coverage application’ to be made to the Minister for Energy requesting that the whole or any part of an electricity network be covered. If a network is covered, it is deemed to be regulated and must have an approved access arrangement in place that sets out the terms of access to the network, including the conditions and prices that apply to the covered services of the network.

Service providers of a regulated network must submit their own access arrangement information to the ERA, which allows:

1. the ERA, users and applicants to understand how the service provider established the proposed arrangement; and
2. the ERA to form an opinion as to whether the proposed access arrangement complies with the Access Code.

Currently, the SWIS is the only regulated network in WA and Western Power is the service provider.

Unlike the NEM, the WEM is described as having a ‘physical firm access’ system whereby generators are only able to connect to the network if they can show that their generation output will not interfere with other generators on the network who have a firm right to export their capacity onto the network. This means that where the network is already constrained in the region where the generator wants to connect its asset, the generator must pay to upgrade the transmission line to alleviate the congestion. This is beneficial in the sense that generators are incentivised to connect in areas of low congestion to avoid the cost of upgrading the network, customers do now bear the costs of network upgrades and once connected generators have certainty that they will be able to export their output. However, the downside of this regime is that it has resulted in an over investment in the transmission line as it has been built to carry the output of all generators at all times, however in practice, not all generators will be exporting at the one time. In turn this has driven up the cost of electricity prices because generator’s pass on the cost of network upgrades through higher prices. This system is threatening to prevent new entrants to the market because while there may be sufficient spare capacity on the network at various times throughout the day, the existing generators have a contractual right to ‘unconstrained network access’, which means that this spare capacity is held aside for the existing generators, thus reducing the available capacity for new generators to connect.

14 Economic Regulation Authority, Guidelines for Access Arrangement Information (6 December 2010), 1.
15 Electricity Networks Access Code 2004 (WA) Section 2.1.
16 Electricity Networks Access Code 2004 (WA) Section 4.1, Section 4.48.
iv Transfers of control and assignments

Where a proposed acquisition may have the actual or likely effect of substantially lessening competition in the market, approval of the proposed transaction may be required under the Competition and Consumer Act 2010 (Cth) from the Australian Competition and Consumer Commission (ACCC). The ACCC may provide either formal or informal clearance, with clearance typically taking up to three months. Alternatively, the Australian Competition Tribunal may grant authorisation based on a 'net public benefit test' where satisfied that the proposal is likely to result in such a benefit to the public that it should be allowed to occur, even if it is likely to substantially lessen competition in the market.

The ACCC has previously expressed concerns about the accumulation of market power through merger activity in the electricity sector, as well as the potential for anticompetitive conduct to ensue from vertically integrated structures.18

Those investors who are either based overseas or owned by a foreign entity must apply to the Foreign Investment Review Board (FIRB) for approval from the Federal Treasurer where they are seeking to acquire a 'substantial interest' in an Australian company (i.e., 20 per cent or more), assets of an Australian business or Australian land. The acquisition of electricity generation or distribution assets by foreign persons and companies is likely to trigger a requirement for FIRB approval. Once FIRB is notified, the board will consider the proposed transaction and assess whether it is against the 'national interest'. New requirements introduced in 2016 allow FIRB to consult with other government departments to determine whether the proposed transaction is within the national interest. The Australian Taxation Office and the ACCC are among the departments that have been actively assessing foreign investment proposals.19

On the recommendation of FIRB, the federal Treasury may then issue a notice of no objection or, where the transaction is against the national interest, disallow the proposed transaction, or impose conditions on how it may be conducted.20 The FIRB approval process generally takes 40 days from the time the application is made; however, FIRB may extend this period for complex applications.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

While the generation, transmission and retail sections of the electricity market were segregated in the 1990s, there has been a trend towards vertical integration by generators and retailers as a means of managing market risk and reducing reliance on hedging arrangements. This trend is true within the private businesses that own most of the generation capacity in Victoria, NSW and South Australia and also the government generators and retailers in Queensland and Tasmania.21

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19 Australian Financial Review, 'ATO to test national interest' (1 April 2016).
20 Foreign Acquisitions and Takeovers Act 1975 (Cth) Section 17.
Similarly, there is a significant degree of vertical integration in WA with Synergy, a state-owned corporation, owning or controlling the majority of generating plants on the SWIS while also supplying over half of the state’s consumable load. Western Power, as another state-owned entity, then owns and operates the distribution network.

Similarly, the NWIS operates though a vertically integrated model, with Horizon Power (also a state-owned entity) being responsible for the generation, procurement, distribution and retail of electricity to customers in the NWIS. The NWIS is owned by significant users of the electricity network: Horizon Power, Alinta Energy, BHP Billiton, Pilbara Iron (Rio Tinto) and ATCO Australia.

ii Transmission/transportation and distribution access

Across the different networks within Australia the connection process is broadly similar. Generators must approach the network service provider with a connection proposal that details the design and technical connection requirements of the generation facility. The network service provider then considers the enquiry or application against set criteria (such as the technical rules for the SWIS in Western Australia and the reliability standards set by the National Electricity Rules on the east coast). The network service providers are responsible for approving the connection of new generation systems to their network. A system can only be connected once all of the applicable connection eligibility criteria have been met, as a means of ensuring that the quality and reliability of supply is of an appropriate standard. The connection of new generation systems may also be subject to the completion of overall network upgrades or the installation of new infrastructure to ensure network capacity is large enough to service the additional generation capacity and community and industrial demand. Therefore, the approval process depends on the size of the system to be embedded and the capacity of the network in the region where it will be installed.

iii Rates

As noted above, in the NEM, network service providers set network charges, but they are limited by a cap on allowable revenue set by the AER. The allowable revenue is set based on the revenue required for the network service provider to cover its costs of reliably supplying customers and to provide an appropriate return on capital.

In relation to the SWIS in Western Australia, a schedule of network charges is submitted by Western Power to the ERA, who then assess and approves the proposed schedule of network charges by reference to the price control and pricing methods in Western Power’s access arrangement.

Security and technology restrictions

As a general principle, all primary equipment on the transmission and distribution system must be protected so that if an equipment fault occurs, the faulted item is automatically removed from service by circuit breakers or fuses. Protection systems must be designed so that, if there is a fault, unnecessary equipment damage is avoided and any reduction in terms of power transfer capability or level of service to users is minimised.\(^\text{26}\)

The scale and changing nature of electricity networks now dictates that security is of greater significance. The roles of key electricity sector stakeholders are changing with a gradual shift toward a shared responsibility for network security, with customers becoming generators that use distributed generation technologies, and vendors assuming new responsibilities to provide advanced technologies as well as their own security mechanisms. With these changes, all stakeholders are becoming responsible for ensuring the continued overall security and resilience of the broader grid, including through:

\(a\) facilitating public–private partnerships to accelerate cybersecurity initiatives for the grid of the 21st century;
\(b\) funding research and development of advanced technology to create a secure and resilient electricity infrastructure;
\(c\) supporting the development of cybersecurity standards to protect against vulnerabilities;
\(d\) facilitating timely sharing of actionable and relevant threat information;
\(e\) advancing risk management strategies to improve decision-making;
\(f\) supporting sector incident management and response; and
\(g\) enhancing and augmenting the cybersecurity workforce within the electric sector.\(^\text{27}\)

With the growth of renewable technologies, the AEMO will be undertaking further studies designed to investigate how the integration of such technologies is likely to affect market operation in the future.

In 2018, the Inaugural Cyber Security Preparedness Report was issued in relation to the NEM and WEM. The report addressed the following issues:

\(a\) the cyber maturity of all energy market participants to understand where there are vulnerabilities;
\(b\) an assessment of current regulatory procedures to ensure they are sufficient to deal with any potential cyber incidents in the NEM;
\(c\) assessment of the AEMO’s cybersecurity capabilities and third party testing; and
\(d\) an update from all energy market participants on how they undertake routine testing and assessment of cybersecurity awareness and detection, including requirements for training employees before they access key systems.

Development of energy markets

\*NEM*

The NEM is a spot market whereby generator’s offer to supply specified amounts of electricity at a set price for set time periods and can revise and resubmit this offer at any time. Based on the bids submitted, AEMO then decides which generation offer to accept and therefore

\(^{26}\) Note 21, above, at 2.9.1.

which generators shall be dispatched to meet demand in the most cost-efficient manner. The spot price for electricity in the NEM is driven by supply and demand and set at half hour intervals. The National Electricity Rules set a maximum spot price which is adjusted annually for inflation.\textsuperscript{28} There is a different spot price in each of the five NEM regions. Customer’s purchase their electricity from a retailer who charges them a set price based on their contract plan. The retailer then bears price risk of fluctuations in the spot price and must manage this risk through entering into wholesale hedging contracts.\textsuperscript{29}

**WEM**

The WEM is a capacity market, with each retailer required to acquire capacity credits from the AEMO, or generators directly, to match their individual capacity requirements. These capacity requirements are based on estimates made by the AEMO in relation to the overall capacity requirement of the SWIS for the next 10 years, in accordance with provisions specified in the Western Australian Market Rules. As well as supplying capacity credits to retailers, the AEMO is also responsible for assigning capacity credits to generation facilities.\textsuperscript{30}

After determining the amount of reserve capacity required, the AEMO places obligations on market customers (i.e., retailers) to purchase capacity credits equivalent to their forecast contribution to peak demand. Those supplying electricity into the network earn ‘capacity credits’ by providing capacity to the system and, where that generation arises from renewable sources, can also earn renewable energy certificates (RECs), which is the general term used to cover small-scale technology certificates and large-scale generation certificates. These are created in the CER’s REC Registry to be bought, sold, traded or surrendered. Commonly referred to as ‘green products’, they can be bought by customers along with the electricity as part of a bundled power purchase arrangement so that customers can use them to meet their own obligations to surrender RECs or sell to the AEMO through a capacity auction.\textsuperscript{31}

In the WEM, only the electricity volume that is not already covered by bilateral contracts is traded. For example, market customers (typically electricity retailers) may need to purchase additional electricity over and above their contracted position because of fluctuations in the weather or unanticipated increases in demand. In this scenario, the market customer bids into the market for the volume of electricity required to balance its contract position and pays market price for that balancing amount of electricity. The WEM’s bilateral net settlement system for uncontracted energy is overseen by the AEMO.

\textsuperscript{28} AEMO, ‘Fact Sheet – the National Electricity Market’.


IV THE YEAR IN REVIEW

i NEM

Significant change is occurring in the NEM that regulators are grappling with at a regulatory level, including the change in:

a the mix of generation facilities connected to the network with a decline in dispatchable generation (with the retirement of aging traditional coal fired plant) and increased renewable generation, which is variable by nature;

b patterns of demand with higher ramping and more customers exporting to the network with their own rooftop generation facilities; and

c weather patterns with prolonged heat waves which are placing more stress on the network.32

AEMO has considered these issues and how they interact which the spot price electricity market and has determined that a market based on real-time spot market price and bilateral contracts is no longer offering the best outcome. This is because with the increased presence of renewables on the network, generators’ are needing to compete with low-cost renewables in the spot market and in situations where the spot price is below that of the generator’s marginal costs, the generator is not incentivised to bid into the market during these periods. Unfortunately, this is compromising reliability on the network because the more stable and traditional dispatchable generators are withdrawing from the market during peak demand periods when such reliability is needed.33 Therefore, AEMO considers that a series of reforms will be required to augment the current market design to better suit supply and demand characteristics going forward by appropriately valuing generation resources with flexibility and dispatchability to incentivise investment in such facilities.34

ii WEM

During 2018 a WEM Reform Coordination Committee was established to manage a three-stage reform process within the WEM to implement an open access regime for the connection of new generation facilities (similar to that in the NEM) by October 2022.35 The reforms aim to make more efficient use of the existing transmission infrastructure, attract private-sector investment by reducing barriers to entry (particularly for renewables) and generally improve the wholesale market to reduce the retail price paid by consumers.36 By

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33 ibid., page 10.
34 ibid., page 11.
Australia

moving to an open access regime it is hoped to make the market more efficient by dispatching to the generator with the lowest-cost power, rather than the generator that has priority accesses to network capacity (i.e., ‘unconstrained access’).\textsuperscript{37} This system ought to make it easier for new renewable generation facilities to connect to the network and also increase their economic viability because with their low operating costs they ought to provide the lowest cost power and therefore be dispatched first. As part of the reform process it is anticipated that those generators with ‘unconstrained access’ will be paid some form of compensation for the loss of that right, which will be negotiated individually with those generators.\textsuperscript{38}

iii Developments in renewables

One of the most publicised recent developments in the renewable energy industry in Australia was the deal struck between the South Australian government and technology company Tesla to deliver up to 50,000 solar power systems for domestic use, utilising Tesla’s domestic lithium-ion batteries.\textsuperscript{39} This project is in addition to the Tesla Powerpack battery system, coined the ‘world’s largest lithium-ion battery’, a 100MW battery that is connected to the Hornsdale wind farm.\textsuperscript{40} The development of lithium ion battery systems is expected to increase the viability of renewable energy power generation on a commercial and domestic scale in the coming years and provide much needed stability to the South Australian grid which had been plagued by load shedding events. The Tesla Powerpack has been in operation since December 2017 and is said to be performing in line with, and in some cases exceeding, expectations in terms of its ability to respond to outages and peaking demand.\textsuperscript{41}

Further, in early 2019 the federal government announced that it would help fund the Snowy Hydro 2.0 project in Tasmania by investing A$1.4 billion in equity. The Snowy Hydro 2.0 project in Tasmania will, if completed, be one of the largest pumped hydro projects in the world and add 2,000MW of energy generation and 175 hours of storage to the NEM. This expansion of Tasmania’s famous Snowy Hydro facility will provide critical storage capacity and dispatchable base load power that will help support the network and counter the influx of intermittent renewable generation facilities.\textsuperscript{42}

\textsuperscript{37} ibid., page 5.
\textsuperscript{38} ibid., page 7.
\textsuperscript{39} Nick Harmsen, Elon Musk’s Tesla and SA Labor reach deal to give solar panels and batteries to 50,000 homes (4 February 2018), www.abc.net.au/news/2018-02-04/elon-musk-tesla-to-give-solar-panels-batteries-to-sa-homes/9394352.
\textsuperscript{40} Nick Harmsen, Elon Musk’s giant lithium ion battery completed by Tesla in SA’s Mid North (24 November 2017), www.abc.net.au/news/2017-11-23/worlds-most-powerful-lithium-ion-battery-finished-in-sa/9183868.
V CONCLUSIONS AND OUTLOOK

The continued transformation of Australia’s electricity market in recent years has, along with the growth of the renewables sector, brought about considerable policy and regulatory changes. Notwithstanding these changes, the energy market in Australia still faces major challenges, the first of which is the geographical isolation that restricts certain areas from being serviced by the existing electricity network. The second is the status of the existing grids’ current regulations and technology, which do not support the optimisation of renewable energy generation. Wind and solar electricity generation offers a clean, green and potentially cost-effective means of meeting the peak electricity demand of Australia’s growing metropolitan population and can also service Australia’s remote off-grid communities through stand-alone facilities. Therefore, it is imperative that Australia invest in the technological research and development, infrastructure upgrades and legislative reforms required to ensure Australia builds on this natural advantage to reduce the cost of electricity for families and businesses while also securing efficient and reliable electricity supplies for future generations.
Chapter 3

BELGIUM

Frederik Vandendriessche and Cedric Degreef

I SUMMARY

As an EU Member State, Belgium has implemented EU energy legislation on electricity and natural gas. Electricity and natural gas markets have been unbundled: a single grid operator is appointed for a designated area. Within this area the grid operator is responsible for the operation, maintenance and development of the grid. The grid operator has to grant non-discriminatory third-party access to producers, suppliers and off-takers against regulated tariffs. The regulatory authority oversees market functioning and compliance by market actors.

Belgium is a federal country where legislative powers over energy matters and policy are divided among the federal and regional governments. The federal government is responsible for legislation regarding large energy generation and storage facilities, nuclear energy, offshore energy, transmission of electricity, transport of gas, and retail energy prices. The regional governments of Flanders, Brussels and Wallonia enact legislation regarding renewables, energy efficiency, distribution grids, and district heating. All governments ought to cooperate on the implementation of Belgium’s long-term energy policy and the shift to a climate neutral economy.

In 2003, Belgium decided to phase out nuclear energy from its energy mix, and to decommission all seven nuclear power plants after 40 years of operation. Given construction took place in the 1970s and 1980s, the last nuclear power plants should be decommissioned by 2025. However, nuclear power plants still account for roughly half of Belgium’s power generation. Furthermore, politics have sent out contradicting signals on the nuclear phase out, so that few efforts have been made by the market or the government to construct alternative (renewable) production units. A draft ‘energy pact’ has been agreed, which will result in a long-term energy policy for Belgium and facilitate the construction of new production units (gas-fired or renewable) to replace the nuclear power plants. As a transitory measure, the extension of the lifetime of the two most recent nuclear power plants Doel 4 and Tihange 2 is being heavily debated.

II REGULATION

i The regulating authorities

Because of its federal structure, regulatory responsibilities are distributed among the federal regulating authority, the Commission for Electricity and Gas Regulation (CREG), and the
three regional energy regulating authorities: the Flemish Regulator of the Electricity and Gas Market (VREG) for Flanders, the Brussels Energy Regulator (BRUGEL) for the Brussels Capital Region, and the Walloon Commission for Energy (CWaPE) for Wallonia.

These authorities are all independent, both from market players and from policymakers. Notably, the regulatory authorities may not receive any direct instructions from ministers or policy makers. They do, however, have to comply with general policy choices.

The core competence of these regulators is grid tariffs. They set the tariff methodologies and approve the grid tariff proposals from the grid operators. In doing so, they must consult stakeholders.

The regulators can also impose administrative fines on market players that do not comply with the energy legislation (e.g., do not possess the required licences). The energy regulators cooperate closely with other market-regulating bodies, such as the antitrust bodies.

ii Regulated activities

Considering that electricity and natural gas markets are unbundled, a distinction has to be made between grid operators on the one hand, and producers and suppliers on the other hand.

Grid operators are appointed for a fixed duration for a designated area. Before being appointed, they must receive an unbundling certification proving that they are operationally and legally independent from other market players such as producers and suppliers. Depending on the level and region, grid operators are appointed by the competent minister or by the energy regulator. Grid operators enjoy a legal monopoly to carry out their activities, but are subject to strict regulatory supervision and to regulated revenue (through the grid tariffs). To develop their grid, grid operators benefit from easements and can use areas that are public property. If more drastic grid development needs to take place, there are specific expropriation procedures in place.

The construction and operation of new onshore power plants requires three permits: (1) a production permit, (2) an environmental permit, and (3) an urban planning permit. In Flanders and Wallonia the latter two have been merged into a single permit. Smaller plants (<25MW) are exempt from the requirement to obtain a production permit. Very small plants, such as photovoltaic installations with consumers, do not require an environmental or planning permit either.

The production permit is granted by the federal Minister for Energy after he or she has obtained advice from the CREG, while the environmental and planning permits are granted by the regions, the provinces or even the municipalities. These different decision levels add to the complexity of constructing new production units, although it should be noted that the production permit is rarely refused after the environmental or planning permit has been obtained.

Offshore power plants require an offshore domain concession (granted by the federal Minister for Energy after he or she has obtained advice from the CREG, among others), a marine protection permit and, as the case may be, a submarine cable licence. Here all permits are granted by the federal level. Until now, only offshore wind farms have been constructed in Belgium.

Finally, a supply licence is required to engage in retail electricity or gas supply. Depending on the voltage level and the regional location of the consumer, a federal or a regional supply licence is required. The duration of a federal supply licence is limited to five years, but it can...
be renewed indefinitely. The regional supply licences have no time limit. Licensed suppliers must also comply with the criteria laid down by law, such as having sufficient technical and financial capacities.

Energy traders do not require a licence to operate on the Belgian market. However, they must communicate certain information (stocks and volumes) to the CREG and other authorities for the purposes of market monitoring.

iii Ownership and market access restrictions
As mentioned above, grid operators must be ownership-unbundled. Furthermore, most grid operators are largely owned by public authorities with the ultimate shareholders being Belgian municipalities. The electricity transmission system operator is a listed company, but almost half of its shares are owned (indirectly) by public authorities. For what concerns the distribution system operators, it is a legal requirement that the distribution grid be fully or mostly owned and operated directly by municipalities or indirectly by inter-municipal cooperative entities.

Except for Flanders, suppliers are required to have a corporate seat in the European Economic Area (EEA). Producers must have their corporate seat, central administration or main office in the EEA also.

iv Transfers of control and assignments
The transfer or assignment of a supply permit or licence, or the merger, acquisition or change of control of the holder of such permit or licence, usually requires a prior notification to the authority that has issued the permit in question.

For an electricity production permit, the federal Minister of Energy must decide within 60 business days whether the permit can be kept or whether a new permit must be applied for. Before deciding on this, he or she will seek the CREG’s advice on the matter. If a new permit must be applied for, the standard procedure applies (approximately three to four months). However, the transfer, assignment, merger, acquisition or change of control can be implemented already.

For an intention to transfer, assign or lease an offshore domain concession, a stand-still period of 50 business days applies during which the Minister for Energy’s representative will assess whether the transaction is compatible with the retention of the concession.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling
Implementing European directives, grid operators in Belgium are ownership-unbundled, meaning that they may not have any direct or indirect participation in or control over any supplier or producer, or vice versa. This model has been implemented gradually since the 90s, with full ownership occurring since the beginning of the millennium. The structure of the industry has therefore not changed significantly over the past few years (except for some mergers and new players on the supplier and producer sides – see below).

ii Access to transmission, transportation and distribution
Grid operators are legally obliged to grant non-discriminatory third-party access to producers, suppliers and off-takers who meet the necessary legal and technical requirements. The grid
codes set out which technical and legal requirements must be met by grid users to have access to the grid. Requirements include signing of an access responsible party (ARP) contract and having a safe and certified installation. The grid codes have recently been revised to comply with the EU Network Codes.

iii Rates

Grid tariffs must be approved by the regulator. The transmission grid tariffs are approved by the CREG, while the distribution grid tariffs are approved by the regional energy regulators VREG, BRUGEL and CWaPE. The grid operators have to submit a tariff proposal, calculating there expected costs and revenue for the coming years. This proposal has to take into account the general tariff guidelines and principles, as set out in tariff methodology (general framework), which is developed by the energy regulator. The grid tariffs are principally fixed for four to five years (the regulatory period). The tariffs of the transmission system operator are based on a cost-plus model, while the distribution grid tariffs are more incentive-based; for example, in Flanders there is a specific stimulant to preserve the quality of the services by the distribution system operators. Costs that stem from a legal obligation (such as public service obligations) or costs that the grid operator merely passes on, may always be fully integrated into the grid tariffs.

iv Security and technology restrictions

There used to be no specific regulation concerning the protection of critical energy infrastructure. However, Flanders has recently introduced a decree granting the Flemish government the power to annul any legal act (so not only share deals, but also contracts) from Flemish public bodies (including Flemish DSOs) that would lead to foreign persons or companies getting control or decision-making power in such bodies, and where there is a risk that (1) the strategic interests of the Flemish government are threatened; (2) certain strategic or sensitive knowledge is likely to fall into foreign hands; or (3) the strategic independence of the Flemish government, including the functioning of the democratic legal order, is compromised. Before annulling a legal act, the Flemish government must first try to reach an amicable settlement with the foreign person or company. Other regions and the Belgian federal level do not yet have similar legislation, but are considering introducing it.

With regard to cybersecurity, it is up to each player to implement adequate software and hardware systems. This is monitored by the energy regulators. Data exchanges between grid operators, suppliers and ARPs happen by means of the data management system MIG.

Access to and import of goods into the nuclear power plants is monitored by the Nuclear Safety Agency and the Belgian State Security Service.

IV ENERGY MARKETS

i Development of energy markets

The opening up of EU electricity markets has led to the introduction of a power stock exchange in Belgium: BELPEX, in short, is the physical power exchange for electricity supply and off-take on the Belgian hub and was established in Brussels in 2006. BELPEX facilitates anonymous, cleared trading in two different market segments, namely a day-ahead market segment (DAM) and a continuous intraday market segment (CIM). BELPEX’s day-ahead market segment is coupled with the APX in the Netherlands and the United Kingdom, the
EPEX Spot in France and Germany, and the Nord Pool Spot in the Nordic region. The intraday market segment is coupled with the APX in the Netherlands and the Nord Pool Spot in the Nordic region.

The futures market is organised by the ICE Endex through the ‘ICE Endex Belgian Power Baseload Futures’ module.

The futures market for gas is organised on the ICE Endex (under the ‘ICE Endex ZTP Natural Gas Futures’ module in monthly, quarterly and annual nominations) and on the PEGAS (the ‘SEA’ module in monthly, quarterly, seasonal- and yearly-nominations and the ‘ZTP’ module in monthly nominations). ICE Endex uses ‘MW’ as a unit, PEGAS uses ‘MWh’ for ZTP and ZEE ‘therms’. The gas spot market is organised on the ICE Endex (the ‘ICE Endex ZTP Natural Gas Daily Futures’ module for the H zone) and on the PEGAS (the ‘PEGAS Spot ZTP’, ‘PEGAS Spot ZTP L’ and ‘PEGAS Spot ZEE’ modules).

On the power market, the ARP is responsible for maintaining a quarter-hourly balance between total injections and total withdrawals of the grid users in its portfolio. The ARP can be a producer, a major customer, an energy supplier or a trader. Each ARP can exchange energy with a view to maintaining a balanced portfolio. Annual, monthly, daily and intraday capacities are allocated by means of different allocation mechanisms. The annual and monthly capacities are allocated by means of explicit auctions. At such auctions, the ARP can acquire the right to import or export a certain volume (in MW) of power for each hour of the year, month or day in question. The transmission system operators (TSOs) in 17 countries of the European Union have created shared rules governing these explicit auctions. The auctions are organised through a jointly created entity called Joint Allocation Office. Daily capacity is allocated to market players through an implicit allocation mechanism (whereby energy and interconnector capacity are seen as bundled products).

Since October 2016, the intraday capacity is allocated via an implicit mechanism based on continuous trading on the intraday markets of EPEX by means of the M7 trading platform.

When the ARP has acquired capacity through the explicit allocation mechanism, it must nominate or schedule the volumes it wishes to import and export: it must submit a nomination to the TSO of the exporting country and one to the TSO of the importing country. The system operators check to see that the details of the two nominations match. For implicit capacity allocation, the ARP does not have to nominate its import or export by itself. The clearing house of the power exchanges organises the cross-border shipping. Capacity obtained by a participant can be resold or transferred via the secondary capacity market.

ii Energy market rules and regulation

Energy market rules are set out in the respective regulation. Market monitoring is done by the regulator. To have access to trading activities, traders must enter into some kind of participation agreement with the hub operator and usually also provide some kind of financial guarantee. Gas traders must also enter into the standard transport contract with Fluxys. Depending on the nature of their activities, electricity traders might have to conclude an ARP agreement with Elia.

iii Contracts for sale of energy

Electricity generators can either enter into direct, private contracts with suppliers and traders or sell their electricity on the wholesale market (over the counter or on the stock exchange).
There are three Belgian gas hubs: Zeebrugge Beach, ZPT (H) and ZTP (L). Trading on these gas hubs previously required the signing of a HUB Services Agreement. However, the HUB services have recently become part of the standard transport contract of Fluxys. The user can submit nominations for ZTP Notional Trading Services, ZTPL Notional Trading Services or Zeebrugge Beach Physical Trading Services. There are regulated tariffs for the use of these HUB services.

Following the liberalisation of the energy market, end consumers are free to choose their electricity and gas suppliers. To protect the consumer from any negative effects as a result of the liberalisation, the federal minister for consumer goods, a majority of the suppliers and the consumer organisation entered into an agreement setting out good practices and consumer protection measures. This agreement is regularly updated.

Furthermore, the regional governments set up a system of social obligations, of which the most important one pertains to maximum pricing, obliging electricity and gas suppliers to supply energy at a fixed price to certain consumers. This price is set by the regulator and adjusted every six months according to the lowest commercial tariff on the electricity market. Only protected and low-income residential consumers or those in a vulnerable situation benefit from this lowest commercial tariff. These protected consumers are placed on the social tariff automatically, regardless of the supplier they choose.

To ensure that every person can live in a dignified way, a DSO must always provide a minimal supply of electricity and gas to consumers, even if the bills are not paid or if the budget meter credits are exhausted. However, the consumer must still pay the cost of this minimal supply. DSOs are only allowed to terminate this minimal supply of electricity and gas in very restricted circumstances. These circumstances are set out in more detail in the respective legislative decrees relating to the sector. In Flanders and Wallonia, the installation of a budget meter is expected in certain circumstances. A budget meter is a device that can limit the supply of electricity and gas, and that is paid for in advance.

iv Market developments
Demand side management and energy flexibility are expected to become more and more important, hence increasing the role of aggregators. In the summer of 2017, a legal framework for commercial energy flexibility was introduced. Each end-consumer has a right to valorise his or her own energy flexibility. To this end, he or she can enter into a contract with an electricity supplier or with a flexible service provider, who in turn must have an ARP or similar contract with the grid operator. Each end-consumer is also the holder of its grid data.

In the European Clean Energy for All Europeans Package, demand-side management also has a prominent role. Smart meters and dynamic electricity price contracts should foster the development of demand-side management, allowing consumers to adapt their consumption to real-time price signals.

The different regions are also developing their own legal framework for technical flexibility.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The Renewable Energy Directive imposes on Belgium a target of 13 per cent of renewable energy consumption by 2020. This target has been further broken down into separate targets, because renewable energy (except for offshore energy) falls under the individual regions’
Belgium

legislative powers. Furthermore, Belgium signed the United Nations 2030 Sustainable Development Goals, which set a target of 18 per cent of renewable energy consumption by 2030. All European Member States have committed themselves to reaching jointly a renewable energy target of 32 per cent by 2030.

It is feasible for Belgium to reach its individual target despite unfavourable geographic and weather conditions in Belgium, but given the division of powers, it will require political cooperation between all of the different Belgian entities.

The principal legal instrument for the promotion of investment in renewable energy sources is the green certificate. Each Belgian region has established its own green certificates system. In Flanders they are called green power certificates and CHP (combined heat and power) certificates; and in the Brussels Capital Region and Wallonia they are called green power certificates. There are also federal green power certificates that are awarded to offshore wind parks and offshore hydro-plants. For the production of geothermal green heat, subsidies are granted through a half yearly call-system.

While the Flemish green power certificates and CHP certificates are awarded on the basis of the green electricity generated (corrected by a banding factor), the Brussels and the Walloon green power certificates are awarded on the basis of CO₂ savings.

Each licensed supplier must submit a certain number of green power certificates, depending on the amount of electricity supplied through the quota obligation. Suppliers can meet their quota obligation by either producing renewable energy (for which they are granted green power certificates) or acquiring green power certificates on the market. Producers of green electricity are granted green power certificates, which they can in turn sell on the market. However, green electricity producers in Flanders and Wallonia can also sell their green certificates to the DSOs (Flanders) or the TSO (Wallonia) at a fixed price. Hence, a minimum price is guaranteed to the renewable energy producers in these two regions.

By Decree of 10 March 2017, the Flemish government adopted a (limited) legal framework on district heating networks. The date of entry into force of this Decree has still to be determined by the government.

ii Energy efficiency and conservation

Rational Energy Use (or energy efficiency) falls under the legislative powers of the regions, but the federal government provides the regions with supporting measures on this. The allocation of legislative powers in the field of energy has made it necessary to organise a consultation between the regions and the federal government. This consultation takes place as part of the Inter-ministerial Conference for Economy and Energy.

EU countries must report annually the progress they have achieved towards their national energy efficiency targets. According to a survey performed by the Energy Efficiency Watch (2015), Belgium is among the EU Member States that have made medium progress in energy efficiency policies since the implementation of the Second Flemish Energy Efficiency Action Plan. A fourth action plan was transmitted to the European Commission in 2017.²

The Buildings Directive 2010/31/EU has been transposed into law by all three Belgian regions. Increased energy performance for buildings is promoted by the regions through energy premium schemes and through certain fiscal measures. Each region has its own variety of schemes and measures for energy efficiency.

² See www.energiesparen.be/EErichtlijn.
Besides, several investment funds and banks are experimenting more and more with energy-saving contracts in the private market. The use of energy saving contracts is encouraged by the European Union, the Belgian federal government and Belgium’s regional governments.

iii Technological developments

The value of the green certificates depends on the technology that is used to generate the renewable energy. Technologies that have become common, such as onshore wind turbines and solar panels, receive fewer euros per MW than more advanced technologies. Innovations may, under certain circumstances and conditions, also benefit from premiums and investment subsidies.

Following the potential from the geothermal energy projects in the northeast of Belgium, the Flemish legislature has amended the Decree of 8 May 2009 on Deep Subsoil. More particularly, a licencing system has been introduced for prospecting and extracting geothermal energy. The licence holder is given real rights, including expropriation rights, if necessary, for building the necessary infrastructure for its geothermal activities. Although the text of the amended decree has been ratified by the Flemish parliament, this amended decree has not yet entered into force. The Flemish legislature has also introduced a guarantee to cover the geothermal risk, which should foster the development of geothermal energy.

Smart metering technology is expected to be gradually rolled out in Flanders in the coming years. No regional initiatives are currently undertaken for Wallonia or the Brussels Capital Region.

VI THE YEAR IN REVIEW

Since the nuclear reactors in Belgium have experienced technical issues (for example, cracks in the concrete walls), they have regularly been offline for maintenance in the past few years. In 2014, Belgium introduced a winter reserve obliging certain production installations that are no longer in the market (e.g., that are shut down and awaiting deconstruction) to be on stand-by in case of an electricity shortage. Currently, the Belgian government is working on a draft proposal to replace this winter reserve with a fully fledged capacity mechanism.

Within its territorial sea and EEZ, Belgium is further developing offshore energy activities. Offshore wind farms used to be heavily subsidised by means of green certificates. Following the examples of offshore wind farms in the Netherlands and Germany that operated without any support by the taxpayers, a deal was struck with the three newest offshore wind farms, Mermaid, Seastar and Northwester 2 (offshore domain concession granted, but not yet operational), to reduce the number of offshore green certificates that would be granted to them. In parallel, the Belgian government is working on a second offshore area for the installation of offshore wind farms. Plots for the new area will be tendered as in the Netherlands via calls for tender for zero-subsidy offshore wind bids.

On the gas market, the gradual depletion of the Groningen natural gas field has prompted the Dutch government to completely phase out low calorific natural gas exports to Belgium and France between 2024 and 2030 and to Germany between 2020 and 2030. In view of this situation, Belgium is preparing to switch to natural gas from other sources (high calorific natural gas, or H-gas). Synergrid, the federation of electricity and gas system operators, has drawn up a technical methodology and a road map for this, which were
discussed with the federal authorities, the CREG and the regions in early 2016. Fluxys Belgium has elaborated the Synergrid roadmap in its 10-year investment plan and is on track to complete the conversion on schedule in 2029.

VII CONCLUSIONS AND OUTLOOK

The Belgian energy market is the result of the implementation of the EU energy liberalisation packages. This has resulted in liberalised energy markets that are gradually evolving into one EU internal energy market. The latest European Clean Energy for All Europeans Package (draft legislation) is to further foster the internal energy market.

The liberalised energy market, in combination with zero-marginal-cost technologies, has lowered commodity prices for electricity and gas significantly. However, the shift to a carbon-free economy and the decentralisation of the energy system (owing to decentralised renewable energy generation) has led to increased grid tariffs and taxes to be paid for renewable support schemes. This has led to an overall higher invoice for the end-consumer. To protect the energy intensive industry, the Belgian legislature has created exceptions for large energy consumers. These exceptions are under increased scrutiny, however, by the European Commission for alleged illegal state aid.

Hydrogen, energy storage, district heating, and geothermal energy are expected to likely be the biggest game changers in the coming years.

From a contractual point of view, corporate power purchase agreements are becoming increasingly frequent on the Belgian energy market.

Finally, Brexit may give rise to a wide range of problems: from new permits and licences to be obtained by UK-based suppliers, over guarantees of origin no longer being valid for submission, to specific trading issues (e.g., on the Nemo electricity interconnector between the UK and Belgium).
I. OVERVIEW

The Brazilian electricity sector, which operates under an integrated and hydrothermal system and with a strongly established free market, is founded on a regulatory framework that provides investors with considerable safety. The market underwent a major restructuring process in the 1990s when it was opened for private investments, and was submitted to further regulatory reform in 2004. Security of supply, regulatory stability and competitiveness provide the basis for the regulatory framework.

The main power source used in Brazil is hydropower (60 per cent of the installed capacity, excluding small plants), while thermal power plants play an important role in complementing the mix and assuring security of supply (23 per cent of the installed capacity). In addition, alternative power sources, notably wind, biomass and solar, have gradually increased their share and gained additional importance in the electricity portfolio. Renewable energy has more recently been encouraged by net metering policies, and has become more competitive over the past few years, as evidenced by the latest power auctions.

The electricity system is connected by transmission facilities that enable electricity produced in remote areas of a continent-sized country like Brazil to be transported to major consumers’ markets, mainly located in the south-east. The grid has its operation centrally coordinated and controlled, to reduce global costs and enhance security of supply, especially during dry seasons.

II. REGULATION

i. The regulators

The Brazilian federal government is empowered by the Constitution to provide services and facilities within the power sector. Private companies are entitled to enter the market through government delegation by concession, permission or authorisation.

The main governmental body responsible for formulating public policies within the energy and mines sectors is the Ministry of Mines and Energy (MME). There are currently other arms of the federal government that play an important role in this sector, namely:

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1 José Roberto Oliva Jr is a partner and Julia Batistella Machado is an associate at Pinheiro Neto Advogados. The authors want to thank Lucas José Russo for his assistance with the research to update this edition.

the National Council on Energy Policy (CNPE), presidential cabinet for energy policy affairs created by Law 9,478/1997; and

the Committee for Monitoring of the Electricity Sector, part of the MME, mainly created as a response to the rationing in 2001 (by Law 10,848/2004), and responsible for monitoring security of supply and suggesting correction measures.

Since the market’s liberalisation, the industry’s participants have been regulated by the Brazilian Electricity Agency (ANEEL),\(^3\) granted with autonomy from central government but attached to the MME. ANEEL, created by Law 9,427/1996, regulates and supervises power generation, transmission, distribution and trading activities to ensure the correct balance between the interests of companies and consumers.

The agency is responsible for implementing the policies and guidelines outlined by the MME, and for monitoring the activities developed in the sector by verifying compliance with its rules and regulations and supervising contract performance. Some of ANEEL’s activities are undertaken by delegation from the MME, such as the conduction of power auctions and the granting of certain regulatory licences. It is important to note that the performance of complementary supervision activities may be decentralised to state regulatory authorities, under the terms established by law.

ANEEL is managed by an executive board composed of a managing director and four other directors, is organised into technical divisions and is charged with performance of administrative functions in different areas such as economic regulation, market studies, supervision, mediation and the granting of concessions and authorisations.

The restructuring processes undergone by the power sector involved the creation of new institutional authorities. The National Electric System Operator (ONS) was created by Law 9,648/1998 as a non-profit association to coordinate and control the operations of the electrical grid, and had its governance system granted even more independence within the 2004 reform. Under the previous regulatory framework, an operational institution was created to manage the wholesale market, which was succeeded by the Electricity Trading Chamber (CCEE) following 2004’s regulatory reform. The CCEE, introduced by Law 10,848/2004, is mainly responsible for the registration of power purchase agreements (PPAs), and for the measurement, accounting and financial settlement of electricity trading operations. Within 2004’s reform, another institutional entity was created: the Energy Research Company (EPE), a public-held company responsible for studies and research on the energy industry with a view to enabling the sector’s planning, as foreseen in Law 10,847/2004.

ii Regulated activities

Since the federal government has the authority to provide electricity services and facilities, private companies need government delegation to enter the market. The regulatory licence required for entrepreneurs to operate in the power sector depends mainly on the segment (generation, transmission, distribution or trading) to be joined, and the extent to which regulation is exercised in each of them. Under the provisions of the legislation currently in force, the MME is the granting authority and may delegate its powers to ANEEL.

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3 In a way, the companies were already subject to regulation before the creation of ANEEL, but the previous governmental bodies lacked effectiveness since they were not granted with autonomy and were part of the central government, which also controlled the state-owned companies that were the main service providers within the sector at the time.
Power generation may be operated by means of a concession of use of public assets, a public service concession (former concessions fall within this regime), an authorisation, or even a communication. The regulatory licence required and the applicable regime depend on the plant’s installed capacity, the power source and the reservoir’s size (a requirement for hydropower plants). Given that the power sector regulation is constantly evolving, we find several legal frameworks co-existing, each from different points in time. As a result, the rules relevant to one power plant may not apply to others, even though they fall under the same regimen. The specifics of the applicable law must always be assessed individually, alongside the provisions of the specific concession agreements.

In general terms, as for new large hydropower plants (HPPs) that have an installed capacity in excess of 50MW, the entrepreneur must participate in power auctions to be granted a concession to operate new generation projects (new-project auctions), and is required to sell a minimum percentage of the plant’s output on the regulated market (the remainder may be sold on the free market). The bid entitles the winning bidder (selected by lowest price criteria) not only to operate the new project (by being granted with a concession of use of public asset), but also to sell electricity to the distribution companies participating in the auction. Companies with hydropower plants in operation may participate in power auctions conducted specifically for purchasing electricity from existing projects (existing-project auctions), or may sell their output on the free market.

On the other hand, an authorisation is required from companies willing to operate small hydropower plants (SHPPs) – which have an installed capacity of up to 30MW and a small reservoir – and plants with a capacity not higher than 50MW that do not have SHPP characteristics. Although the granting of authorisation does not require an auction, the existence of more than one interested company in the same hydroelectric potential triggers a competitive process by which ANEEL selects the entrepreneur, under the provisions of ANEEL’s regulations.

Other energy sources such as thermal, wind and solar are subject to an authorisation regime, whose process is conducted by ANEEL. All of them, including hydropower plants subject to authorisation, may participate in power auctions (either new-project, existing-project, or back-up energy auctions) to sell their production in the regulated market, or may sell it in the free market.

When it comes to new projects, plants subject to an authorisation regime may choose to participate in a power auction to be granted the correspondent authorisation and sell electricity in the regulated market. They may also decide to sell their production in the free market, when they need to undergo an authorisation process with ANEEL to operate the power plant and freely trade the plant’s output.

Small plants – with an installed capacity of up to 5MW for thermal and renewable energy, including hydropower plants – do not need authorisation, but require a communication to ANEEL in light of their reduced impact on the system.

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4 In this case, the auction usually requires that a minimum percentage be allocated to the regulated market.
The regulatory licences mentioned (except for new hydropower concessions, currently only operated by independent producers) can be granted either under an independent power production regime or under a self-production regime. Former concessions are also operated under public service regimes.

Please refer to the table below for a general summary of the regulatory licences required from private investors to enter the Brazilian power generation segment.

<table>
<thead>
<tr>
<th>Power source</th>
<th>Installed capacity</th>
<th>Regulatory licence</th>
<th>Regimes</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hydropower</td>
<td>Greater than 50MW</td>
<td>Concession for use of public asset (preceded by a public auction)</td>
<td>Independent power producer</td>
</tr>
<tr>
<td></td>
<td>Greater than 5MW and not greater than 50MW (certain plants may be characterised as SHPPs)</td>
<td>Authorisation</td>
<td>Independent power producer or self-producer</td>
</tr>
<tr>
<td></td>
<td>Up to 5MW</td>
<td>Communication</td>
<td></td>
</tr>
<tr>
<td>Thermal power plants and renewable energy (except for hydropower)</td>
<td>Greater than 5MW</td>
<td>Authorisation</td>
<td>Independent power producer or self-producer</td>
</tr>
<tr>
<td></td>
<td>Up to 5MW</td>
<td>Communication</td>
<td></td>
</tr>
</tbody>
</table>

There are currently discussions on whether private investors are allowed to participate in nuclear power plants in the country. It has long being understood that private participation is forbidden on account of the federal government’s operation monopoly, foreseen in the Constitution. For that purpose, the state-owned company Eletrobras has a subsidiary, Eletronuclear, which operates two nuclear power plants currently active. However, more recent opinions argue that the Constitution establishes the monopoly of limited parts of the supply chain, such as research, extraction, enrichment, reprocessing, manufacturing and trade of nuclear mining and metals, which would be restricted to the federal government, and that private partners could participate, for example as partners of Eletronuclear or even controllers (subject to a public procurement).

Power transmission and distribution activities are considered natural monopolies, given their dependence on the electrical grid. In this way, most Brazilian power distribution consumers are still legally locked in to purchasing energy from only one intermediary: the local distribution companies to which they are connected. Although there is a special regulation for those who use between 500kW and 3MW, they can choose to buy energy from incentivised sources or small hydropower plants.

In addition, in light of their importance, their operation requires a public service concession, preceded by a mandatory public bid.

Power trading companies wishing to operate in the power market need authorisation under the provisions established by ANEEL’s regulations.

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5 The importance of the difference between the two regimes has diminished since independent producers are entitled to consume part of their production and self-producers are allowed to sell the unused portion of their own output under the conditions set forth by rules and regulations.
iii Ownership and market access restrictions

The Brazilian Constitution establishes that hydropower generation activities must be carried out by Brazilian citizens or companies organised under Brazilian laws, with headquarters and managing offices located in Brazil. The bidding rules of electricity auctions usually do not forbid the participation of foreign companies, but normally establish that:

- foreign companies shall organise a special purpose company under Brazilian laws to have the regulatory licence granted; and
- if foreign companies bid jointly with a Brazilian company in a consortium, the leadership shall always be exercised by the Brazilian company.

In addition, the bid notice usually establishes that foreign companies shall have a legal representative in Brazil with powers to receive service of process and provide answers in the judicial and administrative spheres, as well as represent them in all phases of the proceedings.

The legislation does not forbid electricity companies, organised under Brazilian laws, from being controlled by foreign companies or private equity investment funds organised under foreign legislation (except for nuclear power plants). ANEEL requires, however, that such companies have a legal representative in Brazil, duly vested with powers to receive service of process and provide answers in the judicial and administrative spheres.

In addition, there are specific restrictions for the organisation of power companies in the economic group. Unbundling, adopted by the sector since its restructuring in the 1990s and further deepened in the 2004 regulatory reform, restricted the activities of distribution companies in the regulated market, limiting their participation in other activities of the supply chain. As such, generation and distribution companies operating in the interconnected system are required to maintain separate legal entities and individual accounting, although they may be part of the same corporate group or share infrastructure and human resources when authorised by ANEEL.

iv Transfers of control and assignments

As a rule, the transfer of the regulatory licence or of the controlling interest of the industry’s participants is subject to ANEEL’s prior consent, mainly to adhere to the bidding process and transparency principles.

The regulation in force (ANEEL Resolution 484/12) sets forth that the prior consent of the regulatory agency is required for transfer of controlling interests of public service providers, hydropower companies and nuclear-fuelled energy companies, as well as in any companies, regardless of the power source, whose intended controlling company makes up the corporate group holding or which, with the intended transaction, become the holder of ‘a significant share of the power generation market for the safety of the regulated market’ — a concept yet to be established by the regulatory agency. Some transactions are exempt from consent, under the terms established by ANEEL’s regulations. Nonetheless, the exempt agent has a deadline to inform ANEEL of the implemented transaction and may be also required to maintain a dossier available for inspection.

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The concept of controlling interest adopted by ANEEL is the same as provided in Brazilian corporate law and is associated with prevalence in the company’s corporate and managerial decisions.
The rules currently in force may be further amended after upcoming regulation by the regulatory agency on how ‘a significant share of the power generation market for the safety of the regulated market’ is enacted. This matter has been under discussion at the regulatory agency for a while, without any formal pronouncement yet.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The segregation of the different levels of the production chain was implemented mainly to promote efficiency and competitiveness, given that in the 1990s it became apparent that the vertically integrated industry had proven to be unable to provide services efficiently. The unbundling was formally adopted by the restructuring undertaken in the 1990s, and further enhanced under the 2004 regulatory framework.

The primary purpose of the unbundling in the sector was to encourage competition in the generation and trading segments (which may be provided under competitive regimes), whereas transmission and distribution segments remain natural monopolies. Since the 1990s restructuring, the separation between the contracting of the grid’s access and the purchase of electricity had already been adopted as an unbundling measure.

The current regulatory framework also requires that generation, transmission and distribution activities be undertaken by separate legal entities, with specific restrictions on the corporate structure of their economic groups (see Section II.iii).

The 2004 regulatory reform imposed restrictions on the distribution companies within the interconnected system by forbidding them to undertake any activities in connection with:

a generation;

b transmission;

c sale to non-captive consumers;

d direct or indirect participation in other companies, except for the funding, implementation and management of financial funds for the provision of service; and

e activities unrelated to the purpose of the concession, except for the cases provided by law or in the concession contract.

The legislation has not imposed, however, the unbundling between the segments of generation and transmission, which has remained bundled up in some economic groups.

Furthermore, there is different kind of unbundling under discussion more recently in view of the future expansion of the free power purchase market, and which has not yet been established or implemented. This is the unbundling of distribution services, in order to restrain the distribution monopoly only over electricity transport in the area of concession. Currently, distribution companies have both the monopoly of electricity transport and electricity trade for those consumers qualified as ‘captive consumers’.

ii Transmission/transportation and distribution access

Distribution and transmission companies are subject to regulation of access to their respective grids to avoid discrimination and eliminate barriers to entry. The regulatory framework requires that network companies share and provide access to ‘essential facilities’ to segregate the service provision from the corresponding infrastructure management. For this reason, the electricity sector is governed by the principle of open access to the electrical grid, upon reimbursement of the cost incurred with transportation.
Both ANEEL and the Brazilian Telecommunications Agency (ANATEL) have issued regulations on the reference price applicable to infrastructure sharing (Joint Resolution 04/2014 from ANEEL and ANATEL), because of several disputes over the subject.

### Rates

Power transmission and distribution companies are subject to price regulation, and thus have their revenues calculated by ANEEL, which aims to set prices to promote economic efficiency as if these segments were competitive and not characterised as natural monopolies.

Rates are based on the price-cap mechanism (revenue-cap for transmission companies), and thus are subject to adjustment by an inflation rate; and a productivity factor called the X factor is also applicable. The initial rates or revenues are established in the concession contract resulting from either the auction's competitive process (applicable to new transmission assets), or the privatisation process.

After the initial rates or revenues have been set, they are submitted to annual adjustments for inflation, periodic reviews (every four or five years, depending on the concession contract), and even to further extraordinary reviews to restore the concession's balance upon ANEEL's approval.

Therefore, in the periods between periodic reviews, rates are annually adjusted for inflation (and the X factor is subtracted therefrom). Under this regime, concessionaires are encouraged to be more efficient by reducing costs up to the following price review, when new pricing levels are defined by ANEEL. The price control review process basically aims at setting new efficiency standards to operational costs and to the return of the investments, to ensure that private companies receive an adequate remuneration and that consumers pay fair electricity bills. The new standards established will be valid for the new period up to the following price review.

### ENERGY MARKETS

#### Development of power markets

The 2004 restructuring process that established the current regulatory framework for the Brazilian power sector has envisaged two markets in which participants are able to sell power: the regulated market, and the free market.

Within the regulated market, generation companies sell power to distribution companies participating as buyers in public auctions conducted by the government. Generation companies compete against themselves according to the rules of each auction by the lowest bid price (BRL/MWh) to sell power to the distribution companies. As mentioned above, new-project auctions also involve the granting of concessions or authorisations to enable the winning bidders to operate new power plants.

The regulated market aims at serving the captive market. In other words, the power bought by distribution companies in the auctions is purchased by captive consumers (defined as not having the choice to select their power supplier). As a rule, distribution companies are under obligation to buy power in the regulated market (aside from a few legal exceptions), and to ensure that 100 per cent of their consumers' demand is met.

There are three types of auctions in the regulated market:

- new-project auctions, conducted to promote power generation expansion soon enough to enable plant construction, to meet the market consumption growth;
existing-project auctions, conducted to contract power produced by existing projects, to reduce the financial risks for distribution companies in their demand projections; and

c back-up energy auctions, conducted to increase security of power supply.

The auctions for new projects may include HPPs designated by the government, but companies usually also participate with their own projects (SHPPs, thermal, wind, biomass, and solar projects), which need prior technical qualification before the EPE to be entitled to participate in the auctions. There are also auctions for existing projects, in which generation companies with projects in operation may sell power within the regulated market, and renewable energy auctions, which can be launched for new or existing projects. In the last bids, this type of auction has contracted power originated from SHPPs, wind and biomass plants. The auctions are named A-N (A minus N) that ‘A’ is the year ahead in which the plant must enter operation and start delivering power to the grid.

In the free market, power is freely traded between the parties entitled to participate in it: generation and trading companies, as well as free and special consumers. Free consumers, who may choose their power generation supplier, need to have demand higher than 3MW, although, according to an Ordinance issued by the MME in December 2018, this requirement will be reduced twice in the coming months. The first reduction is set for July 2019, when free consumers will need to have demand higher than 2.5MW, and the second for January 2020, when it will drop to 2MW. Special consumers, which may constitute a consumer or group of consumers that share the same interests, are required to have a demand higher than 500kW and may only choose their supplier when buying from specific renewable sources.

ii Energy market rules and regulations

Sector participants that carry out power trading transactions are under obligation to comply with all of its rules and regulations. As a result of the 2004 regulatory reform, participants must prove that 100 per cent of the power sold in PPAs is associated with generation plants of their own, or belonging to third parties (by means of PPAs to purchase from them), according to the terms set forth by Decree 5,163/2004. While distribution companies need to serve 100 per cent of their market’s demand, sellers need to produce or purchase the same amount sold under PPAs, and consumers need to consume the same amount purchased under PPAs.

If they are not able to produce or purchase the total amount of power traded or consumed, participants will be exposed to the short-term market, proportionally to the amount not produced or purchased, to cover their original PPAs. Financially exposed participants are:

a under the obligation to pay the amount equivalent to the difference between the power contracted and the power delivered or consumed (not covered in additional PPAs), multiplied by the price of financial settlement of differences (PLD), which is defined weekly by the CCEE;7 and

b also subject to penalties imposed by the CCEE.8

7 The CCEE calculates the PLD based on the Operation’s Marginal Cost (CMO) and on a variety of criteria established by legislation (e.g., hydrologic conditions) for each submarket and for each demand level.

8 The CCEE has responsibility for the processes described – the accounting of the market’s traded power amounts and the financial settlement of the values involved in short-term market transactions.
The amount of power allocated to each generation plant is determined by its assured capacity, defined as the maximum amount of power that the plant is allowed to sell and is committed to deliver under PPAs. This calculation is very important as it sets the limit on the power (originating from the plants’ own power generation) available for sale.

The operation of the Brazilian interconnected system may cause the dissociation of the participants’ contractual commitments from the actual physical delivery of the power traded. Power production mainly depends on operational decisions made by the ONS, since a number of power plants are subject to centralised dispatch, which reduces the control that companies have over their own plants’ output. A few regulatory mechanisms have been established to mitigate this risk and avoid financial exposure of these participants for reasons they cannot manage, such as the energy reallocation mechanism, applicable to hydropower plants.

iii Contracts for sale of energy

Within the regulated market, as a result of the auction, long-term power purchase agreements are executed among each of the generation companies that have won the bid and the distribution companies buying at the auction. Similarly, in back-up energy auctions, a back-up energy agreement is executed among the sellers and the CCEE, as a representative of all consumers. All contractual conditions – including supply period, rates (set by the low-bid award criteria), and amounts – are defined within the bid process and are not subject to negotiation.

The contracts’ effective terms depend on each type of auction and power source, and may vary from 15 years to 35 years for new-project auctions, from 1 year to 15 years for existing-project auctions, and for up to 35 years in back-up energy auctions. The PPAs may be executed under two modalities: quantity or availability. Under quantity contracts, sellers assume hydrological risks (variations between the amounts contracted and effectively produced) and deliver the power sold at the submarket where the plant is located. Under availability contracts, buyers assume the risks deriving from the plant’s unavailability resulting in a production lower than the amount contracted.

In the free market, participants execute PPAs in which they freely establish conditions, supply period (short, medium or long term), price and amounts, provided that the contractual terms comply with the sector’s rules and regulations, particularly the CCEE’s trading rules and procedures.

iv Market developments

Some developments have been attained recently. Free and special consumers and small generation participants are eligible for representation in their transactions before the CCEE by a ‘retail trading company’, under the terms established by ANEEL’s regulations. Free-market consumers have also been granted the possibility of assigning power to other participants.

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9 The assured capacity considers the plant's expected production and excludes events of unavailability, and may be lower than the installed capacity of the power plant.

10 While in the regulated market the assured capacity represents the limit available for sale, participants in the free market are able to sell an amount above the assured capacity if they have executed PPAs to cover the total amount sold.

11 Under availability contracts, the remuneration consists of a fixed amount for the plant to be available, and an additional value that varies according to the plant’s effective production.
under the conditions set forth in the applicable regulations, despite not being authorised to sell it. Because of concerns raised about over-contracted distribution companies (to serve the relevant market demand) and about the struggle of generation companies to comply with their construction schedules, ANEEL has issued new regulations on selling of surpluses. The surplus selling mechanism will be applied to reduce the distribution companies’ surpluses by selling them on a competitive negotiation system, which works like an auction, carried out by the CCEE. There is also a special auction to terminate back-up energy contracts of projects that will not become reality. In addition, Law 13,360/2016 allowed the sale of the excess energy by distribution companies to free consumers, under the provisions of ANEEL’s regulations.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

One of the most significant regulatory policies adopted to encourage the development of renewable power in the past has been Proinfa, an incentive programme to encourage the use of alternative power sources, created by Law 10,438/2002. This programme was based on feed-in mechanisms to contract wind, biomass and SHPP projects for a 20-year period. According to the programme regulations, a total of 3,300MW was expected to be contracted under the first phase of Proinfa. The second phase aimed at achieving 10 per cent of the annual energy consumption deriving from renewable sources until 2022, a concept that excludes large hydropower plants. For the currently year, the incentive is evaluated in an amount of 4 billion reais. Proinfa costs are shared among all energy consumers, except low income consumers.

Pursuant to recent information made available in the 2018–2027 Energy Plan, EPE forecast that in 2027 the installed capacity of net metering would reach 11.9GW by means of in 1.35 million systems. This considers that the total install capacity of this type of projects has tripled since 2016. Currently, there are 792MW in 66,115 systems and 89,081 users. Although solar is the most common source, it also expected that wind, hydropower and thermal projects would increase in next years.

Wind power is the source whose participation through regulated auctions has grown the most. EPE has stated in the Energy Plan that, while wind power has become more competitive in price, competitiveness of SHPPs has decreased particularly because of environmental and construction risks. As for solar energy, its installed capacity is still not significant but is also expected to grow.

Renewable energy sources are entitled to some regulatory benefits (such as a discount on fees for use of the electrical grid, and the option of selling power to special consumers, under the terms established by law), and also to some special credit lines from the Brazilian public bank BNDES, the National Bank for Economic and Social Development. Benefits may change in the future as the sources become more competitive, as anticipated in the discussions of a bill of law to implement certain changes in the regulations.

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The Special Incentives Regime for Infrastructure Development, known as REIDI, is a federal tax-incentive scheme for the development of infrastructure that last for five years and is applicable to the purchase of equipment related to power generation and transmission projects, including renewable energy ones, under conditions established by legislation. At the federal level, a tax incentive is granted for ‘infrastructure debentures’ as well. There are also some local incentives granted by states to encourage the development of renewable sources.

ii  Energy efficiency and conservation

The Brazilian power market increase in efficiency during the 2001 rationing, when the market learned how to reduce the consumption required by the government. As the market has suffered unfavourable hydrological conditions in recent years, broad awareness campaigns on the country's exposure to water-shortage conditions have been conducted, possibly as a way of encouraging energy-efficiency measures without recourse to stricter rationing control.

In addition, since January 2015, power rates have been subject to a band pricing scheme, which, by allowing customers to be charged more when the system incurs higher generation costs, represents an important incentive for demand reduction. Moreover, a new pricing scheme is available for certain consumers, those who consume more than 250kWh from January 2019, while others will have the option from 2020. This pricing scheme is also referred to as hourly tariff or white tariff and allows users to pay different rates according to the time and the day of the week of their consumption. ANEEL believes that this change will improve and rebalance the utilisation factor of the system.

iii  Technological developments

In terms of technological developments, the Brazilian market has taken some important steps towards the implementation of smart grid technologies. In addition to regulations on the band pricing scheme, ANEEL has established a net metering policy for renewable micro and mini distributed generation, and has issued regulations imposing a future obligation for distribution companies to install electronic metering for Group B consumers. These measures, taken to allow the integration between power supply and communications technology, aim at improving the quality of service provision and reducing operational costs and technical losses in power supply.

13 Green, yellow and red flags indicate lower, medium and higher generation costs. As a result of the recent water shortages, the ONS has continuously dispatched high-cost thermal power plants since the end of 2012, and consumers have had red flags in their bills for some time.
14 Under this policy, possible excess of the consumer's production is exported into the grid and assigned to the distribution company, and thus may be compensated with credits in the subsequent billing periods, under the conditions set forth by regulations.
15 Residential, rural and other classes, except for low-income consumers and streetlight facilities.
VI THE YEAR IN REVIEW

In 2018, the market experienced a slightly different price scenario than 2017, however not as high as in 2014. ANEEL fostered discussions with the civil society on important trends in the markets, including net metering and binomial tariffs, and passed regulation on the recharge activity of electric vehicles.

In compliance with the current net metering regulations, which established that the rules should be revised before the end of 2019, ANEEL launched a series of public consultations and public hearings to discuss concepts, issue a regulatory impact assessment and finally propose changes in the regulations. One public consultation was already completed in 2018, and two public hearings will be held in 2019. The revision aims to rebalance the costs generated by the current system of net metering that are borne by other consumers and distribution companies, and may increase tariffs paid by net metering users in the future. ANEEL is currently considering respecting the financial expectations of those connecting net metering systems before 2020, which may be subject to lower tariffs than those connecting after this year.

ANEEL published in June 2018 a normative resolution that establishes the procedures and conditions for the recharge activity of electric vehicles. The resolution provides broad language that allows consumers to recharge electric vehicles ‘also for commercial purposes and at freely negotiated prices’. Distribution companies can also install recharging stations in their area of concession for public recharge of electric vehicles. In addition, it provides that the regulatory agency will evaluate the regulatory result within three years.

During the period in review, two transmission auctions were successfully conducted, marking the entrance and consolidation of foreign investors:

\(a\) in December 2018, the bid contracted 7,152km of transmission lines and 14,819MVA in substation capacity in 13 states, with the expected investment of 13.2 billion reais and annual revenue of 1.15 billion reais (46 per cent average discount); and

\(b\) in June 2018, the bid contracted 2,562km of transmission lines and 12,226MVA in substation capacity in 16 States, with the expected investment of 6 billion reais and annual revenue of 451 million reais (55.26 per cent average discount).\(^{17}\)

Generation auctions were also successfully conducted in 2018:

\(a\) in April, the bid contracted 1GW from new projects of power generation from hydroelectric, wind, solar photovoltaic and biomass power plants (estimated investment of 5.3 billion reais);

\(b\) in August, the auction sold 2.1GW from new projects power generation from hydroelectric, wind and thermoelectric, starting in 2026 (an investment of 7.6 billion reais); and

\(c\) in December, the auction sold energy from existing thermal power plants fuelled by natural gas and biomass.\(^{18}\)

\(^{17}\) Information provided by ANEEL. Available at: http://www2.aneel.gov.br/aplicacoes/editais_transmissao/documentos/Planilha%20Resumo%20Leilao%20Transmiss%C3%A3o%20%20PARA%20PUBLICACAO.pdf and http://www2.aneel.gov.br/aplicacoes/editais_transmissao/documentos/Resultados%20Leil%C3%A3o%20Transmiss%C3%A3o%20%20PARA%20PUBLICACAO.pdf.

\(^{18}\) Information provided by ANEEL. Available at: http://www.aneel.gov.br/geracao4.
Mergers and acquisitions transactions were also successfully carried out during the year, including the following:

a. the acquisition, by Enel, of the distribution company Eletropaulo, in state of São Paulo, formerly owned by AES Group;

b. the acquisition, by Votorantim and CPPIB, of the generation company CESP, formerly owned by the government of the state of São Paulo;

c. the acquisition, by Equatorial Energia, of the distribution company Ceal, formerly owned by Eletrobras;

d. the acquisition, by Oliveira Energia and Atem, of the distribution company Amazonas Distribuidora, formerly owned by Eletrobras;

e. the acquisition, by Energisa, of the distribution companies Eletroacre and Ceron, formerly owned by Eletrobras;

f. the acquisition, by Consorcio Oliveira, of the distribution company Boa Vista Energia, formerly owned by Eletrobras; and

g. the acquisition, by Kinross Brasil, of two hydropower plants in the state of Goiás (155MW), formerly owned by Gerdau.

VII CONCLUSIONS AND OUTLOOK

The Brazilian electricity market continued to be eventful in 2018 in spite of the uncertainty surrounding the elections held in October. The coming years are likely to be even more fruitful following the election of Jair Bolsonaro as president. Although there are issues still to be addressed, the sector has been adjusting well to the new economic and political scenario, and important transactions can be expected in the near future.

The market is already responding to the positive signals from election of the new presidency and his team. Competition and the number of new foreign bidders entering the market is expected to increase, following the expected growth of the economy. In addition, in March, the MME for the first time defined a long-term schedule, detailed below, for next year’s energy auctions from new projects (LEN) as well as energy from existing projects (LEE):

<table>
<thead>
<tr>
<th>Year</th>
<th>Auction</th>
<th>Date</th>
</tr>
</thead>
<tbody>
<tr>
<td>2019</td>
<td>LEN A-4</td>
<td>28 June 2019</td>
</tr>
<tr>
<td></td>
<td>LEN A-6</td>
<td>26 September 2019</td>
</tr>
<tr>
<td></td>
<td>LEE A-1 e A-2</td>
<td>6 December 2019</td>
</tr>
<tr>
<td>2020</td>
<td>LEN A-4</td>
<td>23 April 2020</td>
</tr>
<tr>
<td></td>
<td>LEN A-6</td>
<td>24 September 2020</td>
</tr>
<tr>
<td></td>
<td>LEE A-1 e A-2</td>
<td>4 December 2020</td>
</tr>
<tr>
<td>2021</td>
<td>LEN A-4</td>
<td>29 April 2021</td>
</tr>
<tr>
<td></td>
<td>LEN A-6</td>
<td>30 September 2021</td>
</tr>
<tr>
<td></td>
<td>LEE A-1 e A-2</td>
<td>3 December 2021</td>
</tr>
</tbody>
</table>
The new Minister of Mines and Energy Bento Albuquerque Júnior also stated that the government intends to continue the process of privatisation of Eletrobras through new capitalisation.19

In addition, net metering is expected to continue growing also as a result of the public consultations and public hearing carried out by ANEEL, which may benefit those connecting before the end of 2019 with lower tariffs. Furthermore, the expansion of the free market is already set forth in the regulations, with reduced demand requirements entering into force in July 2019 (to 2.5MW) and January 2020 (to 2MW).

The strength of the Brazilian market’s institutions certainly will continue to play an important role in stability. The EPE estimates that investments in centralised power generation in the years 2018–2027 will amount to 226 billion reais and net metering generation to 60 billion reais, and another 108 billion reais in power transmission and substation.20 In sum, the Brazilian power sector should be viewed as a target for long-term investments, to the extent that investors are knowledgeable of the characteristics of each type of investment and are able to accurately assess the risks involved.


Chapter 5

CHINA

Monica Sun, James Zhang and Qiujie Tan

I OVERVIEW

Energy regulation in China involves a number of stakeholders including various governmental authorities that heavily regulate the energy sector, monopolistic state-owned enterprises (SOEs), private companies that are trying to catch up, foreign companies that have had varying degrees of success, and a vast number of consumers. Currently, and for the foreseeable future, energy regulation in China is anchored in China’s ambitious economic restructuring agenda. Top priority is being placed on environmental goals and the deployment of cleaner energy in China’s economic reform plan. The ‘energy revolution’ proposed in the 13th Five Year Plan for National Economic and Social Development (2016 to 2020) is divided into three main sections, namely the upgrade of the energy structure, the development of energy transmission network, and the establishment of a smart energy internet.

China, as one of the largest economies globally, is deeply embedded in the global energy value chain. The effects of China’s energy consumption and production extend well beyond its borders.

China’s prominent role in the global energy market underlines the importance of understanding China’s domestic energy regulation regime and its market structure. This chapter aims to provide an overview of China’s energy market and regulatory regime with a focus on oil and gas, power, and renewable energy from a foreign investment perspective. We have endeavoured to state China’s energy regulation and practice on the basis of the materials available to us as of March 2019.

II REGULATORY REGIME

i Regulators

Oil and gas

The Ministry of Natural Resources (MNR) is responsible for the supervision and administration of the exploration and exploitation of mineral resources throughout China. It has the authority to grant the licences required for the exploration and production of crude oil and natural gas in China. It also plays a role in examination and approval of blocks open to private and foreign investment.

The National Development and Reform Commission (NDRC) is in charge of setting out and implementing policies in respect of the oil and gas sector. It is also responsible
for approving certain investment projects. The National Energy Administration (NEA) is established under the NDRC, with broad duties ranging from drafting energy strategies, proposing reform advice, implementing the management of energy sectors. NEA was previously charged with the authority to exam and approve the overall development plans for individual upstream oil and gas projects (ODP); however, in February 2019, the approval requirements for ODP were officially removed, and were replaced with a record filing procedures and ongoing, post-event supervision by NDRC and NEA.

The Ministry of Commerce (MOFCOM) was previously in charge of review and approval of entry into and amendments of all production sharing contracts (PSCs). This approval is no longer required, and has been replaced with a record filing requirement at MOFCOM since 2013.

**Power**

The NDRC also has the authority to approve certain investment projects in the power industry.

The Market Regulatory Department of the NEA (which took over from the State Electricity Regulatory Commission) regulates the power industry. It is responsible for the enactment and enforcement of regulations in this industry, and also for granting power business permits to power companies.

**Other regulators**

Other regulators include:

- a. the Ministry of Ecology and Environment (MEE): in charge of administering and enforcing environmental protection matters in China;
- b. the National Nuclear Safety Administration: an authority under the MEE that acts as the central government agency responsible for regulating nuclear safety and supervising all civilian nuclear infrastructure in China. It also inspects nuclear safety activities and regulates the project approval mechanism; and
- c. the Ministry of Emergency Management: responsible for overseeing and administering work safety nationwide.

**ii Laws and regulations**

The principle laws and regulations governing the energy sector include the following.

**Oil and gas**

- a. The Mineral Resources Law (1986, amended 1996 and 2009) and its Implementation Rules (1994) establish the basic legal framework under which exploration and production activities (including oil and gas development) are to be carried out.
- b. The Oil and Natural Gas Pipeline Protection Law (2010) provides for the security requirements for the construction and operation of pipelines.


The Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities (for Trial Implementation) (2014) (Third-party Access Measures) provide the third-party access regime, allowing third parties to use the surplus capacity of pipeline facilities.2

The Measures for the Administration of Natural Gas Pipeline Transportation Prices (for Trial Implementation) (2016) provide that the pipeline transportation price is determined by the price administration department under the State Council following the principle of ‘allowed cost plus reasonable profits’.

The Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016) provide that the price administration department under the State Council shall be in charge of the supervision and review of pipeline transportation pricing cost following the principle of legality, the principle of relevance and the principle of rationality.

The Guiding Opinions on Strengthening Regulations over the Gas Distribution Price (2017) provide that gas distribution price shall be determined and reviewed separately, following the principle of ‘allowed cost plus reasonable profits’.

The Opinions regarding Further Reform of Oil and Gas Regime (2017). This ‘Opinions’ document was issued by CCP Central Committee and the State Council, and was long expected to set out a roadmap for the next phase reform in the oil and gas sectors. However, the full text of the document is not yet available in the public domain.

The Regulations on the Administration of Assignment of Mining Right (Draft for Comment) (2019). This draft regulation was issued by the MNR, emphasising the decisive role of the market in the transfer of mining rights.


The Circular on the Reform Plan for Power Prices (2003) sets out the targets for the power price reform and is followed by the Regulation on Feed-in Tariffs (2005), the Regulation on Power Sales Price (2005) and the Regulation on Transmission and Distribution Price (2005).


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2 It is worth noting that this legal document is under review by the NDRC. NDRC has issued Draft Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities for public comments in 2018.
The Regulations on Electricity Regulation were issued in 2005 to strengthen and improve electricity regulation, focusing on maintaining the order of electricity markets and promoting the development of the electric power industry.

The Administrative Regulations on Permits for the Power Industry (2005) focus on maintaining the order of the electricity markets and promoting the development of the electric power industry.

The Opinions regarding Further Reform of the Electric Power Regime (2015) set out the plan for further reform.

The NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) provides implementation measures for the reform of the power regime.

The NDRC and NEA Circular on Issuing Administrative Measures on Electricity Companies’ Entrance and Exit and Administrative Measures on Orderly Derestricting the Electricity Distribution Network Business (2016) provide opportunities for social capital to enter into the electricity distribution industry.

The NDRC and NEA Circular on Orderly Derestricting the Power Generation and Consumption Plans (2017) provides plans for promoting electricity traded through market-based transactions.

The NDRC and NEA Circular on Actively Promoting the Market-oriented Power Transactions and Further Improving the Trading Mechanism (2018) sets out the roadmap to remove restrictions over market players in respect of their participation in seeking market-oriented power transactions.


The NEA Notice on Facilitating the Development of Geothermal Power (2013) is aimed at promoting the development and utilisation of geothermal power.

The NDRC Notice on Adjustment of Feed-in Tariffs for Onshore Wind Power and Photovoltaic Power Generation Projects (2017) provides for the feed-in tariff for onshore and offshore wind farms and solar energy projects.

The Administrative Regulation on Guaranteed Purchase of Renewable Energy-generated Power in Full Amount (2016) sets out detailed rules to guarantee the purchase of renewable energy generated power (excluding hydropower).

The Rules for Issuance and Voluntary Subscription of Green Power Certificate (for Trial Implementation) (2017) provide for the regime of issuing and free trading of green power certificates.


The Circular of the NDRC, the Ministry of Finance (MOF) and the NEA on Matters concerning Photovoltaic Power Generation in 2018 limits the scope and subsidies of the photovoltaic industry in China.
The Circular of the NDRC and the NEA on Positively Promoting the Work on Subsidy-free Grid Price Parity for Wind Power and Photovoltaic Power (2019) aims to implement the subsidy-free policy to reduce subsidies in solar and wind sectors.

In addition, there are numerous regulations and rules enacted by various administrative authorities, to define specific procedures or particular issues with respect to the electricity sector under the framework of the principle law and regulations.

### iii Regulated activities

#### Oil and gas

Upstream oil and gas exploration and production activities are subject to exploration and exploitation licences issued by the MNR.

In the upstream oil and gas sector, foreign companies should partner with and enter into PSCs with legally designated national oil companies (for details, see Section II.iv).

Pipeline design and construction activities are subject to review based on criteria related to safety, environmental protection, optimal land use and economic feasibility. The construction of oil and gas pipeline networks must be approved by the NDRC or its local branches. The qualifications of the enterprises and personnel engaged in the design, installation, use and inspection of pipelines must be accredited by the General Administration for Market Regulatory or its local branch as the case may be.

A specific business permit is required to engage in storage or trading of crude oil, or wholesale, retail or storage of refined oil products.

#### Power

Power companies are required to obtain electric power business permits issued by the NEA. Electric power business permits are divided into three categories depending on the type of business:

- a power generation permit for power generation companies;
- a power transmission permit for power transmission companies; and
- a power supply permit for power supply companies (power supply business is defined to cover both distribution and sale of power).

A company applying for an electric power business licences must demonstrate that it has the financial capability and personnel with the required experience. In addition, power companies must obtain approval for each specific power project from relevant authorities and comply with environmental regulations to be issued with the electric power business licence.

Through an NEA notice issued in April 2014 and further amended in December 2016, the following type of generation projects enjoy a general exemption for a power generation licence:

- distributed generation projects registered or approved by the NEA;
- small hydropower stations with single-station generating capacity below 6MW;
- new-energy generation projects (such as solar, wind, biomass, ocean power and geothermal power) with generating capacity below 6MW;
- power projects with comprehensive use of heat and pressure by-products; and
- captive power plants without direct combustion of fossil fuel and that are dispatched by dispatching organisations at city level or below.
Ownership and market access restrictions

General foreign investment regime

For decades, the foreign investment ownership and access restriction regime was based on a Foreign Investment Industrial Guidance Catalogue issued jointly by the NDRC and MOFCOM; the latest version of which was issued in 2017 (the 2017 Catalogue). Foreign investment activities were divided into three categories: ‘encouraged activities’, ‘restricted activities’ and ‘prohibited activities’. Any activity or sector not listed in the catalogue is ‘permitted’. Those falling in the ‘encouraged’ category would benefit from streamlined approval procedures, tax breaks and other incentives.

In June 2018, after a three-year pilot programme in free trade zones, China rolled out to the entire nation the new ‘negative list’ approach in respect of foreign investment. Accordingly, the ‘restricted’ and ‘prohibited’ categories of the 2017 Catalogues are now replaced by the Special Administrative Measures for Access of Foreign Investment (commonly known as the ‘Foreign Investment Negative List’). There remains a separate negative list applicable to the FTZs with fewer restrictions, the last version of which became effective in July 2018.

On 15 March 2019, the long-expected Foreign Investment Law was passed at the National People’s Congress, which shows China’s determination to make bigger strides in economic liberalisation. The Foreign Investment Law will come into force on 1 January 2020 to replace the existing three pieces of legislations governing the Sino-foreign equity joint ventures, Sino-foreign co-operative joint ventures and wholly foreign-owned enterprises in China.

Oil and gas

The state has ownership over all mineral resources within the territory of China. Pursuant to the Mineral Resources Law, a licensing regime has been adopted and the MNR has the authority to grant exploration licences and production licences.

For conventional oil and gas exploration and production activities, the issuance of exploration licences or exploitation licences are subject to the approval by the State Council. There are only four ‘licensed’ companies, namely China National Petroleum Corporation (CNPC), China Petrochemical Corporation (Sinopec), China National Offshore Oil Corporation (CNOOC) and Shaanxi Yanchang Petroleum (Group) Co, Ltd (Yanchang Petroleum). Under this regime, conventional oil and gas exploration and production activities are not open to other investors in China. However, foreign companies can partner with licensed Chinese oil companies (only CNPC, Sinopec or CNOOC) through the PSC arrangement to invest in onshore and offshore exploration and production in China.

However, the door is gradually opening up for private investment. The first step is marked by pilot reform in Xinjiang province since 2015. Some local SOEs (such as Beijing Energy Holding Co., Ltd and Shenergy Company Limited) and a private company

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3 It is worth noting that the Catalogue of Industries for Encouraged Foreign Investment (Draft for Comment) was issued in February 2019. The format of the 2019 Draft Encouraged Catalogue consists of two regional lists: one for every region of China and another for the central and western regions (the latter list is only applicable for investments into central and western regions, north eastern regions and Hainan Province). If enacted, the 2019 Draft Encouraged Catalogue will increase the number of sectors open to foreign investment, especially in the fields of high-tech manufacturing, artificial intelligence, intelligent technology for health advancement, recycling or environmentally friendly practices, and new agricultural practices.
China

(Zhongman Petroleum and Natural Gas Group Corp Ltd) successfully obtained oil and gas exploration rights through public tendering process initiated by Xinjiang government in 2015 and 2017. Sinopec also has, on limited occasions, partnered with domestic private investors through PSC arrangement; however, the legality of this practice is in a grey area under the current regime. In March 2019, the Annual Report on the Work of the Central Government stipulates that the existing restrictions shall be further released to attract social capital investment into oil and gas exploration and exploitation sector.

Unconventional oil and gas are regulated in various ways. For coal-bed methane, exploration and exploitation generally follows the regime for conventional oil and gas as introduced above. There is more flexibility in other types of unconventional oil and gas. Domestic investors can explore and exploit unconventional oil and gas blocks if they hold relevant qualifications, or choose to establish a joint venture or cooperate with other qualified companies. For foreign investors, the Foreign Investment Negative List has removed the requirement on ‘joint venture or cooperation’ for investment into oil shale, oil sands and share gas since 2017, which means foreign companies can either partner with Chinese companies holding an exploration licence under a PSC, or establish a joint venture with a Chinese partner to bid for the licences directly. Owing to the continuing efforts towards deregulation, future opportunities are expected to be available for wholly foreign-owned companies.

The midstream oil and gas industry is dominated by NOCs. CNPC controls nearly all the long-distance pipelines in China, including the West-East Pipelines system. The CNPC website states that the CNPC owns and controls 68.9 per cent of the nation’s crude oil pipeline and 76.2 per cent natural gas pipelines by the end of 2017. In December 2015, CNPC consolidated a sprawl of pipeline operations in a single company with a registered capital of 80 billion yuan, aiming to improve efficiency and boost the value of the businesses. It was considered a step towards potential divestment in future, as well as a prologue to the government’s bigger plan to reform the energy regime in China. In March 2019, the Annual Report on the Work of the Government confirms that a national oil and gas pipeline network company will be established in China, which is to take over the main pipeline assets from the NOCs.

Construction of new imported LNG receiving terminals of capacity of 3 million tonnes and above is subject to central government approval. Most of the LNG terminals are owned and operated by the three NOCs (i.e., CNOOC, CNPC and Sinopec). In recent years, private entities as well as foreign entities have started to participate in this sector as well. As of the end of 2018, there are three small-scale LNG terminals in operation that have been established by private investment, and several in construction. See Section III.ii for details of third-party access to infrastructure.

The downstream oil and gas sector, including oil refinery, petrochemical production and gasoline retail businesses, is still dominated by NOCs, although it is generally open to private investment and foreign investments, subject to ordinary permitting procedures. In practice, it is less common for foreign-invested companies to obtain such licences, which in fact constitutes a hurdle for foreign investment to further expand its downstream oil and gas business. In February 2019, one subsidiary of Shell incorporated in Zhejiang was granted a refined oil wholesale licence, the first time such licence was granted to a wholly foreign-owned enterprise established by an international oil company.
Power

The main market players in the power industry include generation companies (among which the five large state-owned generators are China Huaneng Group, China Datang Corporation, China Huadian Corporation, State Energy Investment Corporation (through the recent merger of China Guodian Corporation and China Shenhua Group) and State Power Investment Corporation (through the recent merger of China Power Investment and State Nuclear Power Technology Corporation), two grid companies (namely, State Grid Corporation of China and China Southern Power Grid Co) and companies engaged in power engineering and construction business (such as China Energy Engineering Group Co and Power Construction Corporation of China).

The main opportunities for foreign investors in the power industry lie in the construction and operation of power stations with pioneering technologies and in the renewable energy sub-sector. Specifically, the following types of business in the power industry are 'encouraged' in the 2017 Catalogue (as updated by the Foreign Investment Negative List):

a  construction and operation of ultra-supertitical power stations with single unit power of 600,000kW or more;
b  construction and operation of power stations for heat-power co-generation units of back-pressure (extraction-back) type, heat-power-cool multi-generation units, and heat-power co-generation units of 300,000kW or more;
c  construction and operation of power stations with large air-cooled generation units with single unit power of 600,000kW or more in regions suffering from water shortage;
d  construction and operation of projects of power generation via integrated gasification combined cycle and other clean coal power generation projects;
e  construction and operation of power generation projects with single unit power of 300,000kW or more that use fluidised bed boilers and coal gangue, middling, and coal slurry;
f  construction and operation of hydropower stations for the primary purpose of power generation;
g  construction and operation of nuclear power stations (the Chinese party must hold a controlling interest);
h  construction and operation of new-energy power stations (including solar energy, wind energy, geothermal energy, tidal energy, wave energy and biomass energy); and
i  construction and operation of a power grid.

It is worth noting that, although not specifically addressed in the Foreign Investment Negative List, the following types of projects are generally restricted, which applies to all (foreign or domestic) investors, pursuant to Interim Provisions on Construction Management of Small Thermal Power Units (1997) and the NDRC Guiding Catalogue for Industrial Structure Adjustments (2011):

a  power plants utilising coal-fired and steam condensation thermal generator sets whose single generator capacity is 300,000kW or less and connected to small grids;
b  thermoelectric power stations utilising coal-fired steam condensation and extraction thermal generator sets whose single generator capacity is 100,000kW or less and connected to small grids; and

the above types of power plants (in the case of thermoelectric power stations, the capacity threshold is 200,000kW) connected to large grids.
v Transfers of control and assignments

The transfer of exploration rights and exploitation rights for mineral resources (including oil and gas) is subject to the approval of the MNR provided that the following conditions are satisfied:

a) two full years have passed since the issue of the exploration licence, or the discovery of the mineral resources available for further exploration or exploitation in the exploration zone; or one full year has passed since the exploitation enterprise began exploitation;

b) the specified minimum input for exploration has been fulfilled;

c) no disputes have arisen regarding the ownership of the exploration rights and exploitation rights;

d) the exploration right usage fees, exploitation fees or any price for the exploration and exploitation rights have been paid; and

e) a transferee of mineral exploration rights or exploitation rights should meet the qualifications of a mineral exploration right applicant or exploitation right applicant prescribed in the Measures for Area Registration Administration of Mineral Resources Exploration and Survey or the Measures for the Registration Administration of Mineral Resources Exploitation.

The MNR will determine whether to approve the transfer within 40 days of receipt of the application. The transfer will take effect as of the day of approval.

As mentioned above, in most cases, the rights for exploration and exploitation of oil and gas are held by the three NOCs, with whom the foreign investors would enter into a PSC. There is no regulatory requirement for transfer of participating interest under a PSC. Previously, any amendments to the PSC were required to be approved by MOFCOM. This requirement was abolished in 2013 and now only record filing with MOFCOM is required. In terms of operatorship, Chinese PSCs often provide that the consent of a foreign investor is required if the NOCs propose to take over the production operations before foreign contractors’ full recovery of the development costs. After the full recovery of the development costs incurred in accordance with the ODP of any oil or gas field within the contract area, the NOCs may, at any time, have the right to take over the production operations by giving a written notice to the foreign contractor.

Transfer of power generation units in operation requires a change to the power business licence, which needs to be approved by the NEA. The NEA will review if the requirements for granting the relevant licences are still satisfied.

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4 MLR issued a notice in late 2017 which applies only to ‘minerals other than oil and gas’ (note that it is not clear whether oil sands or other types of unconventional oil and gas will fall into this category). For exploration rights acquired by ways of (1) prior application, (2) bidding, (3) auction, or (4) listing, (i.e., other than by ‘private agreement’), the conditions for transfer of exploration right shall include that two years have passed since the issue of the exploration licence, or one year has passed if a geographic report has been filed for recordation after reserve assessment at or above the general survey level. In case where the exploration right was acquired by ‘private agreement’, then ten years shall have passed, otherwise, the requirements and procedures for a new ‘private agreement’ shall apply to such transfers.
iii Transmission/transportation and distribution services

i Vertical integration and unbundling

The State Grid and China Southern Grid control the electricity transmission and distribution networks in China, and are used to monopolise the supply of electricity by purchasing power from power generators at regulated feed-in tariff, and sell power at the regulated power sales prices.

The ongoing power price reform, however, aims to separate the sale of power from grid companies. The Opinions regarding Further Reform of the Electric Power Regime (2015) and the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) provide that power generators will enter into agreements directly with retailers or users with term contracts or spot trades, with the power price being freely negotiated between the parties. The transmission and distribution tariff will be regulated by the government on a ‘cost plus reasonable profits’ basis. According to the Notice by the NDRC regarding Comprehensive Promotion of Pilot Reform of Transmission and Distribution Tariff (2016), this reform is now carried out in most provinces.

Since 2009, the user-generator direct trading system has been put on trial in more than 20 provinces. Companies with high electricity consumption (such as aluminium electrolysis and steel plants) can purchase electricity directly from generators. The price paid by such consumers is composed of the power purchase price negotiated between the generator and the consumer (under a power purchase contract), the transmission and distribution price paid to the grid company (under a service contract) and government surcharges. The Opinions regarding Further Reform of the Electric Power Regime (2015) also set out further goals for the development of this user–generator direct trading system.

ii Transmission/transportation and distribution access

Oil and gas

In 2014, China started a five-year trial period for the third-party access scheme in the oil and gas midstream infrastructures. In addition, the Regulation on Construction and Operation of Natural Gas Infrastructure (2014) encourages investment into natural gas facilities.

Under the Third-party Access Measures, pipeline and facility operators should grant third parties access to pipeline networks and associated facilities if operators have surplus capacity and, in the case of multiple third-party users, non-discrimination principles should apply, but priority should be given to contracts already in place. The facilities to be opened to third parties include not only trunk pipelines and branch pipelines for crude oil, refined oil and natural gas, but also the relevant associated facilities including ports, receiving terminals, and liquefaction, compression and storage facilities. However, there are various issues jeopardising the implementation of the open-access scheme. One of these is the lack of a clear definition of ‘surplus capacity’, and there is no clear mechanism to determine it. As a result, the five-year trial period came to an end in February 2019, during which a very limited number of facilities have been opened for third-party access.

In August 2018, the NDRC issued the draft version of Measures for Regulation of Fair and Open Access to Oil and Gas Pipeline Facilities for public comment (the 2018 Third-party Access Measures), which has not been finalised. This was followed by an announcement in March 2019 that a national pipeline network company is to be established. On the LNG terminals, following a couple of trial runs in late 2018, the CNOOC announced in March
2019 that it is preparing to open up its LNG terminals to third parties for a 10-year term contract via public auction, in a joint effort with the Shanghai Petroleum and Natural Gas Exchange. It remains to be seen how this regime will be developed further in the near future.

**Power**

A grid operator must ensure non-discriminatory and fair access of its grid to qualified power plants and disclose the following information to power plants within its network:

- grid structure and line layouts;
- amount and status of transformation facilities;
- total installed capacity;
- power supply and demand and transmission capacity of major lines and outgoing lines; and
- tariffs and prices for inter-provincial power transactions and direct trading.

An interconnection agreement will be entered into by the grid operator and the power generator, specifying terms and conditions including capacity and feed-in tariff.

Grid companies must ensure non-discriminatory and fair access to their grid to qualified power plants.

For renewable power generation (RPG) enterprises, the grid operators are required to:

- build and manage the interconnection system for qualified RPG projects;
- enter into grid connection agreements with qualified RPG enterprises; and
- purchase all the on-grid power generated by these RPG projects at a higher feed-in tariff.

### iii Rates

**Oil and gas**

According to Measures for the Administration of Natural Gas Pipeline Transportation Prices (for Trial Implementation) (2016) and Measures for the Supervision and Review of Natural Gas Pipeline Transportation Pricing Costs (for Trial Implementation) (2016), inter-provincial pipeline transportation tariffs are regulated by the NDRC on the ‘allowed cost plus reasonable profits’ basis. The NDRC completed the costs assessment of 13 interprovincial pipeline systems in August 2017 and published reduced tariffs effective from September 2017. Such tariffs were adjusted in March 2019 to reflect the reduced VAT rates. Intra-province pipeline transportation tariffs are regulated by local development and reform commission and are reported to the NDRC annually.

According to the NDRC Circular on Issuing the Guiding Opinions on Strengthening Regulations over the Gas Distribution Price (2017), gas distribution price shall be determined and reviewed separately, following the principle of ‘allowed cost plus reasonable profits’. This marks a further big step by the state to achieve the goal of ‘regulating middle while liberalising the front and end’.

**Power**

In theory, the rates that the grid companies charge end users seek to recover power purchase costs and fees for transportation, distribution and sale services, power losses and the like. However, in practice, the rates are set by the government and vary depending on the type of user and the region.
Security and technology restrictions
Oil and gas pipeline owners and operators have obligations under the Oil and Natural Gas Pipeline Protection Law, including those to patrol, inspect and maintain the pipelines; to upgrade, transform or stop using those pipelines that do not satisfy the safe use requirements in a timely manner; to post, repair or change signs related to the pipeline; and to take effective safety protection measures for a pipeline not in operation.

As gas pipelines are considered to be ‘specialised equipment’ under the specialised equipment regulatory regime, a pipeline operator is required to hold a Specialised Equipment Registration Certificate. In addition, both natural gas and gas pipelines are considered to be ‘hazardous material’ under the hazardous material regulatory regime. The ‘producer’ of hazardous material is required to hold a Production Safety Permit and the ‘trader’ of hazardous material is required to hold a Hazardous Material Operation Permit. However, it is not clear whether the pipeline owner and operators will be considered producer or trader of hazardous material.

Power grid operators also have security obligations under the Electricity Law. The power grids shall be operated in accordance with the principles of safety, high quality and economy. Power grid operations must be maintained in an uninterrupted and stable way, with a stable supply of electricity guaranteed.

IV ENERGY MARKETS

i Development of energy markets
The price of refined oil products is regulated by the NDRC. Gas (including LNG) price used to be heavily regulated by the NDRC, but there has been a steady progress of deregulation. According to an NDRC press release, as of October 2017, the price for 50 per cent of all gas consumption in China was completely deregulated, 30 per cent was regulated on base-price basis, and the remaining 20 per cent was for residential use and the price was set by the government. In May 2018, the NDRC issued the Circular on Adjusting the Local Gate Station Prices for Natural Gas for Residential Use, which unified the pricing mechanism for residential and non-residential gas, allowing prices to rise by no more than 20 per cent from a benchmark price and drop to a level agreed by suppliers and purchasers. On 5 September 2018, the State Council issued several Opinions on Promoting the Coordinated and Stable Development of Natural Gas, in order to support the development of strategies on the comprehensive development of the natural gas industry. More supporting policies are expected to be issued in 2019.

In respect of electricity, under the current regime, grid companies purchase power from power-generation companies at regulated fixed prices and sell power to the customers at regulated fixed prices. Generation is dispatched on a fair and equal basis. Under the ongoing power price reform, the Chinese government is exploring the possibility of opening up electricity markets. The aim at this stage is to establish a mid-to-long-term market and a spot market.

ii Energy market rules and regulation
Oil and gas
To engage in crude oil storage or trading, or refined oil wholesale or retail, a specific business permit issued by MOFCOM is required. There are certain requirements for applicants to
obtain a business permit, including a certain amount of registered capital, long-term supply agreements, and stable sales channels and facilities. Foreign-invested enterprises may also apply for permits.

State trading enterprises and non-state trading enterprises may engage in the importation of crude oil and refined oil. MOFCOM publishes a list of state trading enterprises, and companies outside that list may become a non-state trading enterprise if they:

- have a foreign trade business qualification;
- satisfy the requirements published by MOFCOM; and
- register with MOFCOM.

Both state trading enterprises and non-state trading enterprises must obtain an import licence issued by MOFCOM. However, non-state trading enterprises shall be subject to import quotas. This quota for the year 2019 is 202 million tonnes for crude oil. In 2015, MOFCOM issued a notice setting out the detailed requirements for refineries to import crude oil, including requirements regarding equipment, product quality, safety management and personnel.

Use of imported crude oil was previously limited to NOCs. In February 2015, the NDRC issued a notice breaking the monopoly. Local refineries can now apply to use imported crude oil if they meet certain requirements, including requirements regarding equipment, product quality and safety management. Forty refineries have obtained a permit from the NDRC to use imported crude oil as of November 2018.

There is no market entry restriction on the import or export of gas or LNG. In addition, trading of oil and gas requires safety permits under, for example, the hazardous material regulatory regime.

**Power**

Sale of power to customers has been largely controlled by the State Grid and China Southern Grid through their subsidiaries. Under the power sector reform, however, we expect to see more participants in the market. Apart from the user–generator direct trading system, the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) also allows independent power supply companies to participate in the market provided that certain conditions, including on total assets, equipment and expertise, and the electric power business licence issued by NEA, are met.

### Contracts for sale of energy

**Oil and gas**

There are two types of government regulated prices:

- government fixed price; and
- government guidance price.

The former is fixed and there is no flexibility, while the latter is more flexible. Government guidance price can be in the form of:

- a benchmark price with a float range;
- maximum price;
- minimum price;
- the rate of price difference; and
- the profit rate.
When a foreign company invests in upstream oil and gas through the PSC regime, parties would normally agree in the PSC that the NOC will sell the foreign investor’s share of oil and gas on its behalf. Usually the price is determined by reference to the prevailing price in an arm’s-length transaction for a long-term sales contract of similar quality of crude oil in the main world oil markets with adjustment to be made for quality, delivery, transportation, payment and other terms, and expressed as ‘free on board’ price at the delivery point in China.

Upstream crude oil prices and gas prices are not regulated, while refined oil prices and natural gas prices at city gate are subject to government regulation:

a. the retail and wholesale of gasoline and diesel, as well as sale of gasoline and diesel to wholesale business, railway customers and transportation customers are subject to the governmental guidance price; and

b. the supply of gasoline and diesel for state reserves or Xinjiang Production and Construction Corps as well as the factory price of aviation gasoline are subject to government (fixed) pricing.

The price of gasoline and diesel will be adjusted every 10 business days based on international crude oil price, processing cost, taxes, transmission fees and reasonable profits.

The government provides for base price of natural gas at the city gate (which means parties may negotiate the city gate price and such price shall not exceed 120 per cent of base price) while the ex-factory price can be negotiated between parties. The prices of gas produced from shale gas, coal-bed methane, coal gas and imported LNG are deregulated and can be determined by parties. The price for direct sale arrangement between CNPC/Sinopec and industrial users under ‘direct supply arrangement’ is also deregulated. In order to accelerate the gas price reform, the state started a pilot programme in Fujian province in November 2016, whereby the city gate prices will be determined freely based on negotiation between the supplier (CNPC) and consumers (utilities), and not subject to government regulation.

**Power**

To a large extent, the power prices are set by the government, taking into account the power purchasing cost, the loss from power transmission and distribution, power transmission and distribution price and government funds. The prices vary depending on a number of factors including season, peak hour, region and type of user (namely, residential user, agricultural user and industrial and commercial user).

Customers are allowed to participate in the power market if certain criteria are met, and may choose to enter into power purchase agreements with (1) power supply companies, or (2) directly with power generators. The terms and conditions of these agreements can be freely negotiated between two parties.

The Opinions regarding Further Reform of the Electric Power Regime (2015) and the NDRC and NEA Circular on Issuing Supporting Documents for Electric Power System Reforms (2015) set out future steps to further facilitate the reform, including determining qualified generators based on energy conservation and environment protection requirements; expanding the direct trading to power supply companies; and encouraging long-term agreements between generators and customers.

The NDRC and NEA issued the Circular on Actively Promoting the Market-oriented Power Transactions and Further Improving the Trading Mechanism in 2018, which
stipulates a further increase in the scale of market-oriented trading power trading, the speed of development of power consumption plans, the scope of market entities, and the active promotion of the participation of various market entities in power market transactions.

V RENEWABLE ENERGY AND CONSERVATION

As part of government policies in response to climate change and in line with China’s commitments to the international community, the State Council set an objective to control energy consumption to 5 billion tonnes of standard coal in the 13th Five-Year Plan period (2016 to 2020). The NDRC also set Mid-to-Long Term Plans for renewable energy development: 10 per cent of the total energy consumption should be sourced from renewable energy by 2010, and 15 per cent by 2020. The midterm target (10 per cent by 2010) has been achieved. In July 2017, the NEA issued Guidelines of the National Energy Administration on the Implementation of the 13th Five-Year Development Plan for Renewable Energy, listing the overall development plan for wind power, biomass and solar plants for 2017–2020.

In addition, the Chinese government has established a clean development mechanism fund to support construction and industrial activities that are beneficial to strengthen proper responses to climate change since 2010. The construction and operation of power stations using renewable energy is ‘encouraged’ under the 2017 Catalogue.

Under the current power regime, the government sets higher feed-in tariffs (FITs) to encourage power generation from renewable energy. The tables below set out the latest policy on feed-in tariffs for wind, biomass and solar power.

Wind and biomass

<table>
<thead>
<tr>
<th>Electricity source</th>
<th>FITs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Wind</td>
<td>Onshore project: four tiers ranging from 0.4 yuan/kWh to 0.57 yuan/kWh, depending on project locations (for projects approved after 1 January 2018 and projects approved before 1 January 2018 but not in construction at the end of 2019). Offshore projects: 0.85 yuan/kWh or 0.75 yuan/kWh depending on the distance to shore. However, for the 2019 newly approved centralised onshore wind power projects and offshore wind power projects, feed-in tariffs shall be configured and determined through competition, as per the Notice on the Relevant Requirements for Wind Power Construction Management in 2018 issued by the NEA.</td>
</tr>
<tr>
<td>Biomass</td>
<td>0.75 yuan/kWh,</td>
</tr>
</tbody>
</table>

Solar

<table>
<thead>
<tr>
<th>Resource area</th>
<th>Centralised PV Feed-in tariff</th>
<th>Distributed PV Subsidy payments</th>
</tr>
</thead>
<tbody>
<tr>
<td>General</td>
<td>0.55 yuan/kWh</td>
<td>0.65 yuan/kWh</td>
</tr>
<tr>
<td>Poverty alleviation projects</td>
<td>0.65 yuan/kWh</td>
<td></td>
</tr>
<tr>
<td>Class I regions</td>
<td>0.65 yuan/kWh</td>
<td>0.75 yuan/kWh</td>
</tr>
<tr>
<td>Class II regions</td>
<td>0.75 yuan/kWh</td>
<td>0.85 yuan/kWh</td>
</tr>
<tr>
<td>Class III regions</td>
<td>0.75 yuan/kWh</td>
<td>0.37 yuan/kWh</td>
</tr>
<tr>
<td>1. The PV power plant feed-in tariff in Tibet is 1.05 yuan/kWh.</td>
<td></td>
<td></td>
</tr>
<tr>
<td>2. The FIT and subsidies for PV projects are decreasing over the years, and the rates above are applicable to new projects to be subsidised through the annual quota system from 2018 onwards.</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

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Other incentives include:

- surcharges collected from all electricity end users are used to subsidise the difference between feed-in tariffs and the benchmark price for desulphurised coal generators, operations and maintenance for independent public power systems, and costs for connecting renewable energy generators to power grids;
- favourable loans with financial discounts for renewable energy projects listed in the guidance catalogue for renewable energy industry development;
- subsidies for renewable energy development in areas such as new-energy vehicles, building-integrated solar photovoltaic systems, wind turbines and biomass power generation; and
- tax incentives.

However, it is worth noting that the Action Plan (2014–2020) for Energy Development Strategy marks a concerted shift to a more market-driven approach to future build out in China. To implement such plan, the Circular on Photovoltaic Power Generation (2018) and the Circular on Positively Promoting the Work on Subsidy-free Grid Price Parity for Wind Power and Photovoltaic Power (2019) were issued to gradually reduce subsidies in the solar and wind sectors.

After Fukushima, the NDRC approved a nuclear project in March 2015 marking the official relaunch of nuclear projects in China. The Mid-to-Long Development Plan of Nuclear Power by the State Council sets the target for nuclear power at installed capacity of 58 million kW and 30 million kW under construction by 2020, which means a shortfall of 39 million kW. The industry was expecting a large wave of investment into nuclear power in the near future. In January 2019, two units of Zhangzhou Nuclear Project Phase I (jointly invested by China National Nuclear Corporation and China Guodian Corporation) and two units of Huizhou Taipingling Nuclear Project Phase I (invested by China General Nuclear Power Corporation) were finally approved by the State Council, which marked the end of three-year period during which no new nuclear projects were approved. In early April 2019, NDRC issued a new circular providing that first batch of third-generation nuclear power projects shall apply feed-in tariff on a case-by-case basis.

In order to help reduce government subsidies to the renewables sector, the NDRC, together with the Ministry of Finance and the NEA, issued a Circular on the Trial Implementation of the Renewable Energy Green Power Certificate Issuance and Voluntary Subscription Transaction System (the Green Power Certificate Circular) in January 2017. According to the Green Power Certificate Circular, solar and wind power producers would apply for and be issued tradeable certificates for the renewable electricity generated by them. End users are encouraged to buy such certificates at an agreed price through negotiation or a bidding process. Solar and wind power producers will not receive a direct subsidy (higher FITs) for the electricity corresponding to the certificates sold. In July 2017, an official website for trading of the Green Power Certificate was launched. As of March 2019, while over 25 million certificates were issued, only around 33,000 certificates were traded.

Also aiming to promote clean energy, a carbon emissions trading system has been operated on a pilot basis in parallel. In December 2017, the NDRC announced the plan to roll it out to the national level. The interaction and reconciliation between the green certificate regime and the carbon emissions trading system are to be further observed in the future.
VI  THE YEAR IN REVIEW

In February 2017, the State Council released the 13th Five Year Plan for Energy Development (2016 to 2020), listing future energy strategies for an efficient, clean and safe energy system. According to the Plan, the annual primary energy consumption will be capped at an amount equivalent to 5 billion tonnes of standard coal by 2020. The Plan sets goals on future energy structure, with at least 15 per cent of energy supplied from non-fossil fuels, 20 per cent supplied from natural gas and at most 58 per cent from coal by 2020.

China continues towards achieving the marketisation of its energy supply. Gas price deregulation is the most advanced in progress compared to other sub-sectors. In May 2018, China unified the pricing mechanism for residential and non-residential gas, a long expected milestone in the pricing reform roadmap. The deregulation of gas price coincides with a jump in gas demand. In 2018, the total gas consumption increased to 280 billion cubic metres. 53 per cent of the gas supply comes from importation of LNG. China has become one of the most active natural gas and LNG markets in the worldwide.

In 2018, China intends to streamline and further open up its oil and gas industry. Despite the oil and gas exploration and exploitation business is denominated by NOCs, China is now trying to encourage social capital into the upstream business. The plan on establishment of the national oil and gas pipeline network company which is expected to attract private investment marks one of the essential steps in separation of transmission businesses. The shooting demand on LNG supply attracts more and more interests from private investors and foreign investors to develop LNG receiving terminals in China.

Electricity market reform is ongoing. The year of 2018 witnesses the launch of pilot spot market trading in Guangdong, Gansu and Shanxi. The market-oriented electricity trading is pushed by the central government through new policy encouraging direct sales arrangement and participation of more diversified market players. In renewable sector, China decided to tap the brakes for fast-growing wind and solar industry through a reduction of subsidies. Resumption on nuclear power projects also shows the government’s determination to diversify the supply of energy.

In March 2019, the Foreign Investment Law was promulgated amid the trade war between China and the US. The law aims to provide a level playing field for foreign investment into China, including in particular the national treatment for foreign investors in all business activities other than those specifically set out in the Foreign Investment Negative List. As a piece of policy-driven legislation, it only contains around 40 clauses with general and broad terms; some of the more controversial operative provisions, which were considered and debated in earlier drafts, were left out. It remains to be seen how the new law will be implemented in practice, and how it will coordinate with and promote the further opening up of energy markets in China.

VII  CONCLUSIONS AND OUTLOOK

The regulatory environment is changing fast in China, and the energy sector is no exception. Both the economic restructuring plan and the development of green-energy technology have had a profound influence on the energy industry. Various stakeholders and their demands contribute to innovation in the industry, while also adding complexity to the reform process. With reforms taking place in the regulatory regime and the restructuring of the market ongoing, it is vital to keep a close eye on energy regulations in China.
I OVERVIEW

In past decades, the energy sector in Colombia has been one of the main pillars of development and growth of the country’s economy while contributing significantly to the national budget, which is devoted to infrastructure and social development, as result of the collection of royalties, taxes and dividends.

Although nowadays the country is a target for international investment, having extensive trade relations and an attractive business environment, it is undeniable that there is currently an environment of uncertainty in Colombia, which has had adverse effects on international investment and on the country’s credit rating. Nevertheless, some elements should be highlighted as providing a positive boost for the economy and investment: the ongoing implementation of the peace process with the Armed Revolutionary Forces of Colombia (FARC) ending an armed conflict of over 50 years and the election of the young right-wing former senator Ivan Duque as President of the Republic, who has actively promoted boosting investment as one of the government’s goals. However, one of the positive aspects discussed in last year’s chapter was the reactivation of the peace talks between the National Liberation Army (ELN) and the government, peace talks that were recently ended due to the ELN’s persistence in carrying out terrorist acts, including attacks on power lines and stations.

As result of the terms of the Colombian Constitution of 1991, the Colombian electricity sector has been transformed from a sector wholly owned by the government into a sector where there is a clear separation between the roles of service providers and utility companies, and regulators, policymakers and control and oversight agencies. Since then, this sector has existed on three main levels. First the Ministry of Mines and Energy (MME), which governs policy and establishes the long-term plans for the whole sector. Second, the Energy and Gas Regulation Commission (CREG), which sets out the rules and roles of each of the participating agents, while also focusing on quality and price for the end user. And third, the Superintendence of Domiciliary Public Utilities (SSPD), which is an inspection, monitoring and surveillance body that oversees operators and guarantees supply to the end user.

The main power source used in Colombia is hydropower, which represents 77.97 per cent of the installed capacity, followed by thermal power stations operating with coal and

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1 José Vicente Zapata is a partner and Daniel Fajardo Villada is an associate at Holland & Knight.
gas with a share of 14.62 per cent. The remaining energy is obtained and supported by other sources such as cogeneration, with a share of 1.22 per cent, and wind power, which adds 0.1 per cent.\(^4\)

In terms of connectivity, the Colombian electricity sector is divided into the National Interconnected System (SIN), which comprises generation plants, the interconnection network, and regional and interregional transmission and distribution networks; and the non-interconnected zones, where electricity services are not provided by the national network but by independent small-scale systems.

II REGULATION

i Regulators

The Colombian Constitution, issued in 1991, conferred legislative power on Congress and granted regulatory power to the national government, which in turn exercises such power through the regulatory entities that serve the energy sector via decrees and resolutions. Specifically, the determination of policies and issuance of regulation is undertaken by several government entities, as follows.

On the one hand, the MME is the government entity responsible for formulating, adopting, directing and coordinating the policies, plans and programmes of the mining and energy sector in Colombia as well as the supervision of the electricity sector. The MME regulates generation, interconnection, transmission and distribution activities and is in charge of generation and transmission programmes.

On the other hand, the administration and issuance of regulations in the electricity sector is dealt with by the following technical entities:

\(a\) CREG, a special administrative body created in 1994, is responsible of the regulation and promotion of competition between the entities involved in the electricity sector and the regulation of electricity and gas utilities. Pursuant to Laws 142 and 143 of 1994, the following specific functions are assigned to CREG:

- promoting fair market competition;
- setting out the conditions for deregulation of the electricity sector regarding a competitive market;
- determining and approving interconnection and usage charges and tariffs for the transmission and distribution of electricity;
- defining the regulated and unregulated end-user markets;
- setting out the regulations for the operation, planning and coordination of the national transmission system; and
- issuing the technical regulations with respect to quality, reliability and security of electricity;

\(b\) the UPME is a special administrative unit attached to the MME in charge of planning the energy mining sector in coordination with other agents in the sector and supporting the MME in achieving its goals and objectives;

the Institute for Planning and Promotion of Energy Solutions for Non-Interconnected Areas is responsible for the promotion, development and implementation of energy efficient, viable and sustainable solutions that meet the needs of non-interconnected zones; and

d the SSPD is a government agency that oversees public utilities companies that operate within the Colombian territory. Among other functions, the SSPD conducts:

- supervising the quality and efficiency of all public service companies;
- taking over public utilities companies when the companies are financially non-viable or when the service rendered is at risk; and
- imposing sanctions on the companies subject to surveillance, and in particular with respect to electricity companies as result of a violation of the code of operations of the electricity sector.

In addition to the above-mentioned entities, the following entities provide consultation and technical assistance in the electricity sector:

- The National Operation Council, responsible for determining the technical standards for the efficient operation and integration of the SIN; and
- the Commercialisation Advisory Board, created by CREG as an advisory entity for the monitoring and review of the commercial aspects of the wholesale energy market (MEM).

The Superintendence of Industry and Commerce (SIC) is the authority in charge of investigating and sanctioning commercial restrictive practices, as well as authorising the mergers of companies operating within a single sector and market.

ii Regulated activities

Environmental permits

From an environmental perspective, the development of works and activities related to electricity or nuclear energy requires a prior licence or environmental permit to be granted by the National Environmental Licensing Authority (ANLA) or regional entities, depending on the sector, type of project and area where it is developed.

Furthermore, the main regulation in relation to environmental authorisations is Decree 1076 of 2015, which, among other things, defines the environmental authority in charge of granting the environmental licence, depending on the type of project and the installed capacity (MW) of the specific project.\(^5\)

Pursuant to Decree 1076 of 2015, an environmental licence is the authorisation granted by the competent environmental authority for the execution of a project, work or activity, which can cause serious deterioration of natural resources or the environment or introduce significant modifications to the landscape. Environmental licences include all permits, authorisations and concessions for the use of renewable natural resources throughout the duration of the project, work or activity, and any requisites for the initiation of the work, project or activity subject to an environmental licence.

\(^5\) Article 2.2.2.3.2.1, Decree No. 1076 of 2015.
Pursuant to the ILO Convention 169 and Colombian regulations, should ethnic communities be located within the area of influence of the project, a prior consultation process with such communities must be undertaken prior to the issuance of the environmental licence. Prior consultation suspends the proceeding with respect to the environmental licence.

**Electricity: regulated activities**

It is of utmost importance to note that, pursuant to the Colombian Constitution, electricity generation, interconnection, transmission and commercialisation activities are considered public utilities to be provided under Colombia’s authority and supervision and governed by the constitutional principles of free economic activity, free private initiative, free competition and private ownership.

The primary electricity regulation is contained in Laws 142 and 143 of 1994, which were enacted in a context of severe energy insufficiency and outages. Until 1995, electricity services were provided by the state through the company Interconexión Eléctrica SA (ISA) and other government-owned entities, with minor participation of the private sector. The power sector was reformed to introduce market economy principles, assigning the state the role of regulator. ISA was spun off into two companies: ISA the transmission company with system and market operating functions, and ISAGEN, a new company for electricity generation.

Law 142 regulates all aspects related to energy as a public service, and Law 143 sets out the legal regime applicable to the generation, interconnection, transmission, distribution and commercialisation as well as the Wholesale Electricity Market, which came into operation in July 1995. Furthermore, Law 143 of 1994 states that all the activities that involve the supply chain of electricity, from generation to commercialisation, are intended to satisfy primary collective needs on a permanent basis and thus considered as mandatory public utilities, essential in nature.

In relation to projects, free private initiative is the general rule and thus, private and public–private partnerships may get involved in the generation, transmission, distribution and commercialisation of electricity without requiring a concession. In other words, this means that Colombia will only get involved in the development of electricity generation projects when no private entity is willing to assume such activity.6

iii Ownership and market access restrictions

In Colombia, there are no limitations or prohibitions for foreign participation or investment in the electricity sector. The only sectors in which foreign investment is prohibited are national security and defence and processing and disposal of toxic, hazardous or radioactive waste, as specified by Article 6 of Decree 2080 of 2000, further amended by Decree 2466 of 2007.7

Nevertheless, pursuant to Article 471 of the Code of Commerce, foreign companies willing to undertake permanent business in the country are required to constitute a branch with local address in Colombia. Moreover, according to Law 142 of 1994, enterprises providing public utilities, such as companies participating in the electricity sector, must be constituted as public utilities companies.

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6 See Article 56 of Law 143 of 1994.
7 Compiled in Article 2.17.2.2.3.1 of Decree 1068 of 2015.
Regarding the electricity sector, as of the issuance of Laws 142 and 143 of 1994, generation, transmission, distribution and commercialisation of energy are considered as isolated activities. Furthermore, Article 74 of Law 143 of 1994 expressly prohibits companies involved in the electricity sector to engage in more than one activity except for commercialisation, which can be developed along with other activities of the electricity sector.

In addition, CREG regulations have set out specific restrictions as follows:

a. electricity generators are not allowed to have an equity participation of more than 25 per cent in distribution companies;

b. no company can have market participation above 25 per cent in the generation activity;\(^8\)

and

c. no company is allowed to directly or indirectly own more than 25 per cent of the equity of a company involved in commercialisation of electricity.\(^9\)

### iv Transfers of control and assignments

With respect to mergers and acquisitions, it is important to note that all companies involved in the electricity sector are subject to the general competition and antitrust regime provided for in Law 1340 of 2009.

Pursuant to Article 9 of Law 1340 of 2009 and Resolution 10930 of 2015 issued by the SIC, certain mergers, consolidations or integrations require either to be approved or to be notified to the SIC.

Mergers require notice to the SIC when they meet the following conditions:

a. whenever the transaction creates any form of integration. Any transaction to acquire ‘control’ over assets or shares of other companies leading to the creation or reinforcement of market power constitutes a merger;

b. the parties of the transaction in Colombia jointly or individually have, in the year prior to the transaction, a level of total assets or operational income equal to or above 60,000 minimum monthly Colombian legal wages;

c. whenever the companies involved in the transaction are dedicated to the same activity or participate in the same vertical value chain; and

d. whenever at the time of notice companies have:
   - 20 per cent or less market participation; or
   - 20 per cent or less participation in the same vertical value chain.

Notice must be submitted as a pre-completion requirement of the transaction. However, this filing does not constitute a merger clearance by any means. Mergers will require approval of the SIC when they meet the first three above-mentioned conditions and the market participation of the companies individually or jointly equals or exceeds 20 per cent of the relevant market under Colombian jurisdiction.

Approval must be submitted as a pre-completion requirement of the transaction; the SIC’s clearance is therefore a mandatory condition in order to proceed with completion of the transaction.

In addition to the above, Article 34 of Law 142 of 1994 mandates that companies involved in public utilities must avoid unjustified privileges and discriminatory acts and must refrain from undertaking any act or transaction that has the capacity, purpose or effect of

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\(^8\) See CREG Resolution 60 of 2007.

generating unfair trade, restricting competition or abuse of dominant position. The SSPD is the entity in charge of monitoring compliance of the aforementioned obligation and imposing sanctions.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

As indicated above, the electricity Law 143 of 1994 and CREG regulation establish unbundling rules restricting horizontal and vertical integration of utility companies that provide electricity services. Integration rules indicate the following:

a utility companies incorporated before Laws 142 and 143 of 1994 can develop more than one activity under separate accounts for each business; and

b utility companies constituted after the enactment of Laws 142 and 143 of 1994 can only undertake, at the same time, complementary activities such as generation-retailing or distribution retailing and are prohibited to simultaneously perform activities of generation transmission, generation-distribution, transmission-distribution and transmission-retailing.

With respect to horizontal integrations, as it was previously stated, pursuant to Resolution 128 of 1996 of the CREG, a single company may not own more than 25 per cent of country’s generation, retailing and distribution activities.

ii Transmission/transportation and distribution access

The electric power system consists of an interconnected grid – the SIN – that supplies about 95 per cent of the overall demand. The remaining demand (non-interconnected zones) is typically supplied by local small electricity generation plants that operate on fossil fuels (gasoline and diesel).

The SIN has a total length of 26,333.49 km comprising the following:

a the SIN;

b the regional transmission system; and

c the local distribution system.

The National Transmission System is a multi-owner network that has the unique characteristics of a natural monopoly, with ISA holding the largest share.

The grid system supply, provided by the National Transmission System, enables the coordination of the generators while reducing the amount of backup generating capacity and reserves. Pursuant to applicable regulations, transmission is defined as the transportation of electricity at a tension level equal to or greater than 220kV. Networks operating at less than 220kV are part of the distribution activity, the main function of which is to transport the electric energy to the end user. Moreover, the electric distribution system is integrated by networks, substations that operate at voltages lower than 220kV and do not belong to the National Transmission System.

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With respect to third-party participation, it is important to note that the National Transmission System operates on an open market basis, and thus transmission operators must provide open access to customers on a non-discriminatory basis, while receiving regulated revenues using transmission system charges. These charges are regulated by CREG, paid by electricity consumers and further collected by retailers.

In addition to the above, Colombia is interconnected with both Ecuador and Venezuela, which has fostered the development of energy security standards while allowing these electricity markets to operate in a coordinated manner.

### Rates

Pursuant to Article 23 of Law 143 of 1994, CREG:

- **c)** Defines the methodology for the calculation of rates for access and use of electric grids as well as the rates for services related to connection and coordination which are carried out by regional dispatch centres and the national dispatch centre.

- **d)** Approves the rates to be paid in relation to access and use of electric grids as well as the rates for services related to connection and coordination which are carried out by regional dispatch centres and the national dispatch centre.

Further, Article 88, numeral 1 of Law 142 of 1994 provides that:

> Companies should adhere to the formulas that CREG periodically defines to fix their rates, except in the exceptional cases listed below. According to cost studies, the regulatory commission may establish maximum and minimum tariff caps which are mandatory for companies; while it may also define methodologies for determining rates and whether it is appropriate to apply the regime of regulated or supervised rates.

In relation to the regime of regulated and supervised rates, Article 11 of Law 143 of 1994 establishes a regulated liberty regime according to which rates for generation, interconnection, transmission, distribution and commercialisation of electricity within the national territory is set and limited by the criteria and methodology of CREG.

While each company negotiates its own rate, as mentioned above, rates are capped at the maximum rate established by CREG. For affixing rates to be charged for utilities, CREG establishes the methodology and procedure for the calculation of the rate including costs associated to such rate. Thus, resolutions that set rates include the costs assumed by the provider of such service as well as the methodology used for regulating such cost.

Furthermore, Article 87 No. 9 of Law 142 of 1994 provides that the rates and formulas to calculate such rates fixed by the CREG may be modified by the CREG every five years and when the law so provides. However, Article 126 of Law 142 of 1994 indicates that the formulas to calculate the rates will be valid for five years, unless otherwise agreed between the CREG and the utility companies. The current rates are those set by way of Resolution 097 of 2008 issued by CREG. While it is evident that such Resolution 097 of 2008 was issued more than five years ago, it should be noted that a modification and adjustment proposal has already been drafted and has not yet been approved.
iv  Security and technology restrictions

The main concern in terms of security of the electricity sector in Colombia is related to physical security of the oil and energy infrastructure. For several decades, infrastructure was a common target for guerrilla groups related to the armed conflict within the country. Attacks to pipelines as well as energy towers were frequent; they implied serious damages, paralysis of some parts of the system and impacted production levels gravely, affecting vulnerable populations. A decrease and eventual halt in attacks to oil and energy infrastructure is expected as a result of the implementation of the peace process with FARC, and as a result of ongoing negotiations with the National Liberation Army.

While recent developments in terms of peace have substantially diminished attacks to oil platforms, pipelines and energy towers, in 2014, before the negotiation and subsequent implementation of the peace process with FARC, the Colombian government created a task force for the protection of infrastructure including pipelines, energy towers, oil platforms and infrastructure in general, which was named COPEI. Among the various outcomes of the implementation of such task force were the creation of a special operation centre and the distribution of a daily report including possible threats and events.

IV  ENERGY MARKETS

i  Development of energy markets

The Colombian energy market is based on a competitive market model that is accessible through the MEM. The MEM is a market in which generators, transmitters and wholesale energy consumers and unregulated users participate with the main purpose of trading energy blocks through the SIN.

The MEM is divided into long-term and short-term transactions, depending on the needs of those participating in the MEM and the terms for such negotiations. For example, long-term participants opt for bilateral agreements while short term agreements usually refer to next-day purchases between all the generators of the market, which are subject to explicit regulations. These kinds of transactions usually cover the spot market.

Oversight of the MEM is led by the SSPD, which created the Oversight Committee of the MEM in 2006.

A substantial amount of electricity that is generated in Colombia is traded through the MEM via wholesale transactions, as all the generation companies are obliged to participate in the MEM with all of their generation plants and units that are connected to the SIN.

Retail companies that sell directly to end users are also required to carry out their electricity transactions through the MEM.

ii  Contracts for sale of energy

As explained above, the MEM is divided into long-term and short-term transactions. While long-term transactions usually involve bilateral agreements, short-term transactions (referred to as ‘on spot transactions’) usually involve negotiations of daily price offers along with hourly availability. The prices at which electricity is offered reflect the variable costs of generation as well as opportunity costs.
Firm energy obligation auctions

Allocation of firm energy obligations (OEFs) between the different generators and investors is effectuated through dynamic auctions. OEFs are the resulting links from the auctions, according to which generators must generate a daily amount of electricity, as long as the obligation is in force. When the stock market price exceeds the price of shortage, the OEF price is determined by descending clock auctions.\(^1\)\(^\text{11}\) The purpose of such auctions is to allocate firm energy obligations (between the generators and investors), thus ensuring reliability in long-term firm energy supply at efficient prices.\(^1\)\(^\text{12}\) Auctions are held three years prior to the date when the firm energy is required. The time between the announcement of the auction date and the end of the obligation term consists of three stages: (1) the pre-qualifying period; (2) the planning period; and (3) the obligation effectiveness period, the total of which varies from one to 20 years.\(^1\)\(^\text{13}\)

Bilateral contracts

The bilateral contracts market is primarily a financial market, as its function is to reduce exposure of the generator and end user to short-term price volatility. Such contracts are freely agreed commitments acquired by generators and commercialisation companies to sell and buy electricity. Energy is delivered though the spot market by the generator indicated in the contract, or by another generator as determined by the ideal dispatch (see below). The only requirement in such agreements is that the contract specifies the amount of energy that will be used on an hourly basis. Aside from that requirement, there are no restrictions on the electricity that a generator or commercialisation company may specify in the contracts, or the time frame covered by such agreements. Energy purchases made through such contracts, intended for regulated users, are governed by rules that guarantee competition among generators, while the prices and conditions on such contracts intended for non-regulated users are freely negotiated and agreed by the parties.\(^1\)\(^\text{14}\)

Spot market

In the spot market the transmission network is neutral, thus implying that the generator makes its price offer for each day and its availability declaration for each hour, without considering the state of the transmission network. The resources that will be dispatched in order to comply with the hour-by-hour demand are selected according to the most economic offers. This dispatch is known as the ideal dispatch, as it diverges from the real dispatch, which considers the restrictions that may affect the transmission network. The ideal dispatch is determined once finalised by the National Dispatch Centre. It considers real demand and availability, not considering physical and technical restrictions imposed by the transmission network. Price offers presented by the generators must reflect the variable costs of generation and opportunity costs. The spot price is the price of the last resource used to meet the total

\(^{11}\) Article 2, CREG Resolution 071/2006.
energy demand every hour, which establishes the price at which all submarginal resources in the same hour will be remunerated. The part of the energy demand from commercialisation companies not covered by bilateral contracts must be paid at this spot price.¹⁵

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Most of the developments in terms of renewable energy have been a result of the issuance of Law 1715 of 2014, which aims, inter alia, to promote the development and use of unconventional sources of energy, mainly renewable energy, in the national energy system, as a means to achieve sustainable development, reduce greenhouse gas emissions, ensure the country’s energy supply and promote efficient energy management. This law establishes the legal framework and instruments required to take advantage of unconventional sources of energy and renewable energy, while promoting investment, research and development of clean technologies for energy production, energy efficiency and demand response.

The law defines unconventional sources of energy as environmentally sustainable energy resources that are globally recognised but in Colombia are not widely used or are not widely marketed, such as nuclear or atomic energy, unconventional sources of renewable energy and those determined by UPME. Further, it defines as unconventional sources of renewable energy as sources of energy that meet the above characteristics and are also renewable energy resources, such as biomass, small hydroelectric, wind, geothermal, solar, sea and solid waste that is not susceptible to being reused and recycled and which UPME has deemed to be environmentally sustainable.

Law 1715 of 2014 classifies activities related to the production and use of non-conventional energy sources (mainly non-renewable energy) as matters of public utility and social interest, with the purpose of facilitating certain requirements, processes and access to benefits in urban planning, territorial planning, environmental planning, economic development and the right to compulsory expropriation, etc. It also assigns competence to entities such as the ANLA and regional autonomous corporations to implement rapid evaluation cycles for projects related to non-conventional sources of energy, and for matters pertaining to this Law.

This Law is especially relevant as it authorises small and large-scale energy self-generators to surrender their surplus to the distribution and transport network, in accordance with the regulations of CREG, and the allocation of energy credits to small-scale energy self-generators using non-conventional sources of renewable energy. Such credits may be negotiated with third parties, in accordance with the regulations issued by CREG. The fund for non-conventional renewable energies and the efficient management of energy (FENOGE) has also been established to finance programmes and projects in this area.

In relation to the above, in February 2018 a change was introduced to the energy sector with regard to the generation and distribution of energy: CREG ruled that users of the electric power service in the country could produce energy and sell it to the SIN.¹⁶ This refers

¹⁶ See CREG Resolution 30 of 2018.
to small-scale self-generation, up to 1MW, and distributed generation, by means of which all residential users, as well as commercial and small industrial users, who produce energy mainly to meet their own needs, can sell the surplus to the interconnected system.

Law 1715 of 2014 sets out important fiscal, customs and accounting incentives for companies investing in projects of non-conventional sources of energy.

In fiscal matters, it offers an annual reduction in the income tax, for five years after the taxable year in which it makes the investment: 50 per cent of the total value of the investment made, without exceeding 50 per cent of the net income of the taxpayer determined before subtracting the value of the investment.

For these purposes, the taxpayer must obtain a certification of environmental benefit issued by the Ministry of Environment and Sustainable Development. In addition, national or imported equipment, elements, machinery and services that are intended for the pre-investment and investment for the production and use of energy from unconventional sources and for the measurement and evaluation of potential resources will be excluded from the VAT. For these purposes, a certification from the Ministry of the Environment must be provided stating the equipment and services that will benefit from this award, according to the list established by the UPME.

With respect to custom incentives, Law 1715 provides that those who import machinery, equipment, materials and supplies destined exclusively for pre-investment and investment in projects from non-conventional sources of energy are entitled to obtain an exemption with respect to tariff duties.

Finally, as an accounting incentive, companies participating in generation activities with non-conventional energy sources can enjoy the accelerated depreciation benefit, at a depreciation rate of no more than 20 per cent per annum, applicable to machinery, equipment and civil works necessary for pre-investment, investment and operation of such sources, provided that they have been acquired or constructed exclusively for that purpose, and after the validity of this law.

For its full implementation, Law 1715 requires regulation in different governmental entities affected by the measures of the law. Thus, to date, the following aspects have already been regulated, according to the information published by the Ministry of Mines and Energy on its website www.minminas.gov.co:

\[a\] Decree 0570 of 23 March 2018 of the Ministry of Mines and Energy, which establishes the public policy guidelines to define and implement a mechanism that promotes long-term contracting for electric power generation projects and that is complementary to the existing mechanisms in the MEM. Additionally, it indicates that the aforementioned mechanism shall endeavour to comply with the following objectives:

- through the diversification of risk, it will strengthen the resilience of the electric power generation matrix during events of variability and climate change;
- it will promote competition and increase efficiency in the creation of prices through long-term contracting of new or existing electric power generation projects;
- it will mitigate the effects of variability and climate change through the use of the potential and complementarity of available renewable energy resources that manage the risk of supplying for future electricity demand;
- it will promote sustainable economic development and strengthen regional energy security; and
reduce greenhouse gas emissions of the electricity generation sector, to comply with the commitments made by Colombia at the 2015 Paris Climate Change World Summit.

b
Decree 1543 of 16 September 2017 of the Ministry of Mines and Energy, which regulates the FENOGE;

c
Resolution 1670 of 15 August 2017 of the Ministry of Environment and Sustainable Development, which adopted the terms of reference for the preparation of the environmental impact study in projects for electric power transmission systems;

d
Resolution 1312 of 11 August 2016 of the Ministry of Environment and Sustainable Development, which adopted the terms of reference for the preparation of the environmental impact study in projects for the use of wind energy sources and other aspects;

e
Resolution 1283 of 8 August 2016 of the Ministry of the Environment and Sustainable Development, which establishes the procedure and the requirements of the certification of environmental benefit to obtain the tax benefits granted by law;

f
Resolution UPME 045 of 3 February 2016, which establishes the procedures and requirements for issuing certification and endorsing projects from non-conventional energy sources in order to obtain the benefit of VAT exclusion and exemption from the tariff levy; and

g
Decree 2143 of 4 November 2015, issued by the Ministry of Mines and Energy in relation to the definition of the guidelines for the application of incentives established in Chapter III of the law.

In addition, a Decree that intends to develop Law 1715 of 2014, by regulating and providing the guidelines for defining a mechanism for the long-term contracting of generation projects with non-conventional sources of energy (FNCER), in relation to the promotion, development and use of FNCER is yet to be issued.

**Energy efficiency and conservation**

The energy efficiency area of the MME developed the Programme for the Rational Use of Energy and the Use of Renewable Sources of Energy, which aims for energy efficiency and establishes targets for unconventional renewable energies in the SIN, as stated in Law 697 of 2001.

The most recent regulatory advance can also be found in Law 1715 of 2014, which, among other things, orders the MME, together with the Ministry of Environment and Sustainable Development and the Ministry of Finance, to jointly develop an action plan for the development of technical regulations with respect to renewable energies; consumer information on the energy efficiency of processes; facilities, services, products and manufactured products; and information; as well as to promote campaigns on the use of renewable energy sources.

In addition to the above, Law 1715 provides that the national government and public administrations should establish energy efficiency objectives in public buildings and plans and actions of efficient energy management.
iii Technological developments

In addition to the tax and customs incentives created by way of regulation issued in response to Law 1715 of 2014, and certain programmes to provide electricity and the use of unconventional renewable resources in remote areas, no significant regulatory additional developments have been made in the areas of renewable energy and conservation.

However, it must be highlighted that renewable and clean energy projects became especially relevant during 2018 and the first months of 2019, to the extent that it was the first time that in an OEF auction, solar and wind energy were incorporated into the electricity matrix (1398MW installed, representing 6 per cent of installed capacity); the first environmental licence for the generation of photovoltaic energy was granted by the environmental authority; and the first renewable energy auction was carried out by the government. This auction did not result in any awards, since the proposals presented would have resulted in market concentration in excess of the limits set forth in the applicable regulation. The government plans to hold an additional renewable energy auction in the course of 2019.

VI THE YEAR IN REVIEW

In 2018, the Colombian energy sector was strongly influenced by an event related to the biggest developing energy project in the country, the Ituango hydroelectric plant, Hidroituango. Hidroituango is designed to be capable of providing 17 per cent of Colombia’s electricity supply, and it was supposed to enter into operation by the end of 2018. However, due to structural damage during the construction process, it is now expected that the project will be subject to at least a three-year delay before it is finished and fully operating.

As a consequence, the government called an OEF auction specifically for the reliability charge. Initially, this auction was planned for the allocation of OEF for the 2022–2023 period. However, due to the urgent need to generate electricity as a result of the delay in Hidroituango’s construction – which could lead to an energy shortage, the CREG established incentives for projects that could commence operation before December 2021, the point at which it is estimated there may be an energy deficit.

The reliability charge auction was held on 28 February 2019 and 70 of the 80 projects submitted were awarded. From the awarded projects, 47 were presented by existing plants (electric power generation plants already in commercial operation at the time of the auction), and the remaining projects were presented by new plants (electric power generation plants that have not started construction or that were in this process at the time of the auction). The closing price of the auction was 15.1 US dollars/(MWh), which represents a decrease of 11 per cent compared to the price defined in the last reliability charge auction.

17 ANLA, ‘ANLA aprueba primera licencia para generación de energía fotovoltaica. Available at: http://www.anla.gov.co/Noticias-ANLA/ANLA-aprueba-primera-licencia-para-generaci%C3%B3n-de-energ%C3%ADa-fotovoltaica, accessed 16 March 2019.

18 Defined as: the maximum amount of electric energy that a plant is able to generate on a continual basis during a year, in extreme conditions of hydro inflows. CREG, ‘Firm Energy Obligation’. Available at: http://www.creg.gov.co/cxc/english/obligacion_energia_firme/obligacion_energia_firmes.htm, accessed 17 March 2019.
VII CONCLUSIONS AND OUTLOOK

The Colombian electricity sector has come a long way since the power outages during the 1990s. Privatisation, promotion of investment as well as implementation of regulations have transformed the Colombian electricity sector into an attractive and competitive market in the region.

However, the rapid expansion of the sector and the ongoing dependence on resource-driven sources of energy such as hydroelectric power, still have the capacity to bring the system to a halt, as the 'El Niño' phenomenon showed in early 2016.

In addition to the foregoing, foreign investors have adopted a more cautious attitude towards the country because of the environment of legal uncertainty generated by certain governmental and judicial decisions, especially by the Constitutional Court. Nonetheless, the new government has openly encouraged foreign investment and is creating a positive environment for investors.

The main objectives and challenges faced by the Colombian electricity sector to develop and secure the Colombian market include:

a providing greater legal security to investors;
b attracting greater investment in the electricity sector;
c promoting unconventional renewable resources, aiming to achieve self-sustainable and permanent energy sources;
d advancing regional electric integration;
e increasing the installed capacity and effective generation and reliability; and
f drafting and issuing the necessary regulations for supply and projects of non-conventional renewable energy.
Chapter 7

DENMARK

Nicolaj Kleist

1

I OVERVIEW

The Danish energy demand is met by domestic natural gas resources and oil, coal imports, and domestic renewable energy sources such as waste, woodchips, sun, wind and biogas. There is no large hydropower or nuclear power production in Denmark.

The first oil and gas exploration licence was granted in 1935, and since then oil and gas have been exploited in Denmark. In 1966, hydrocarbons were discovered in the North Sea, and in 1972 the first oil was produced. During the first 50 years, exploration of oil was carried out under sole-right concessions, but in 1983 competitive licensing rounds were introduced and the first licences with more than one concession holder were awarded in 1984 – the latest in 2016. Oil and gas activities are governed by the Subsoil Act,2 which lays down the basic framework for oil and gas exploration and production.

The first comprehensive legislation governing electricity supply entered into force on 1 January 1977. Electricity activities are mainly governed by the Electricity Supply Act,3 which lays down the basic framework for electricity production and supply. The aim has been to ensure electricity supply in accordance with the principles of security of supply, economics, and environmental and consumer protection. Access to cheap electricity and consumer influence on the administration of electricity sector assets; promoting sustainable energy use, including in connection with energy savings and use of combined power and heating; lasting and environmentally compatible energy sources, as well as securing effective use of financial resources; and creating competition on the markets for production and trade in electricity are essential elements in the legislation.

The long-term goal of Danish energy and climate policy is to have the total energy demand covered by renewable energy by 2050. The government and the parties of the Danish parliament entered into an agreement on 29 June 2018 that sets new objectives for 2030 towards the goal of reaching a net zero emissions society by 2050. By 2030 it is expected that 55 per cent of the total energy consumption in Denmark will come from renewable energy. Wind power alone is expected to cover up to 53–59 per cent of electricity consumption in 2020, and the goal for 2030 will partially be reached by establishing three new offshore wind farms, each with a capacity of at least 800MW.

1 Nicolaj Kleist is a partner at Bruun & Hjejle.
2 Act No. 1190 of 21 September 2018 on the Use of Danish Subsoil.
3 Act No. 52 of 17 January 2019 on the Supply of Electricity.

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II REGULATION

i The regulators

The overall administrative responsibility for the energy sector lies with the Danish Minister for Energy, Utilities and Climate (the Minister). Part of the Minister’s authority has been delegated to the Danish Energy Agency (DEA). The DEA is responsible for the entire chain of tasks linked to energy production and supply, transportation and consumption, including energy efficiency and savings as well as national carbon dioxide targets and initiatives to limit emissions of greenhouse gases. In cooperation with the Minister, the DEA prepares the majority of the bills and other political proposals. The DEA carries out analyses and estimates of the development in the energy sector and represents Denmark in international forums.

The Danish Utility Regulator (DUR) controls prices and conditions in the energy sector. DUR’s purpose is to ensure an efficient and transparent energy market in Denmark. Transmission, storage and distribution undertakings and supply-committed undertakings are under the supervision of the DUR. Decisions of DUR may be appealed to the Energy Board of Appeal. Decisions by the Energy Board of Appeal cannot be brought before any other administrative body, but may be challenged before the courts.

Energinet, a state-owned undertaking, owns, operates and develops the Danish transmission network for electricity and gas and is responsible for effective and safe supply and for a competitive energy market. Energinet must ensure open and equal access to the transmission networks for all users. It also issues rules on gas transport and coordinates the general planning of emergency supply for the natural gas sector. By March 2019, Energinet has also acquired the entire Danish gas distribution network.

The city councils in the municipalities are responsible for the planning of local heat supply. In each municipality, the city council must carry out planning in cooperation with the supply undertakings and other stakeholders.

The Energy Supplies Complaint Board is a private board established by the energy industry and the Danish Consumer Council. The Energy Supplies Complaints Board handles complaints about the purchase and delivery of energy from supply undertakings. As a principal rule, the board only accepts complaints from consumers. Decisions of the Board cannot be appealed to any administrative authority, but can be brought before the courts.

The main legislation for energy regulation is the Continental Shelf Act, the Act on Raw Materials, the Subsoil Act, the Pipeline Act, the Natural Gas Supply Act, the Heat Supply Act and the Electricity Supply Act.

4 www.efkm.dk.
5 www.ens.dk.
6 www.forsyningstilsynet.dk.
7 www.ekn.dk.
8 Established by Act No. 1097 of 8 November 2011.
9 Act No. 64 of 21 January 2019.
10 Act No. 1189 of 21 September 2018.
12 See footnote 2, above.
15 See footnote 9, above.
16 See footnote 3, above.
ii Regulated activities

A licence issued by the DEA is necessary for exploration, production, transmission, distribution and storage activities.\(^{17}\)

A permit is required for the establishment of plants and for expansion or changes to such plants causing increased pollution.\(^{18}\) Permits are issued by the relevant city council or regional council depending on the size of the plant. Permits for major plants require a prior public hearing, and for major plants there may be a duty to complete an environment impact assessment under the Planning Act.\(^{19}\) Offshore plants are primarily subject to approval under the Subsoil Act and Continental Shelf Act. Offshore installations are subject to approvals and permits issued by the DEA. These include operation permit, manning and organisation plan approval and approval for the contingency plan. To obtain an operation permit, there must be an evaluation of safety and health conditions for the installation and the operational conditions (health and safety review/safety case) and other relevant information regarding health and safety conditions (e.g., certificates). Offshore installations operating in Denmark must have a workplace assessment system.

iii Ownership and market access restrictions

The Danish state has a general right to all hydrocarbons in the subsoil of the Danish territorial jurisdiction area. The state can grant licences for preliminary investigation, exploration and production of hydrocarbons. Licences are granted through tender procedures or under the ‘open door’ procedure.

The main part of the natural gas on the Danish market is produced in the Danish North Sea. Through the Danish North Sea Fund, the Danish state participates in concessions for exploration and production of hydrocarbons. The fund is administered by the Danish North Sea Partner, a unit under the Ministry. The fund, which was established in 2005, is the Danish state’s oil and gas company, which contributes to the decision-making processes in connection with exploration, production and development activities with respect to Danish licences. The aim is to use existing knowledge across licences and support the development of new technologies that can enhance the recovery rate of oil and gas resources in the subsoil.

Partly state-owned Ørsted A/S (previously DONG Energy) owns upstream pipelines and operates the gas treatment plant at Nybro. The establishment and operation of upstream pipeline networks require a licence issued by the DEA. Any interested party is entitled to access an upstream pipeline network subject to payment. In March 2019, Energinet’s last acquisition of the gas distribution network was finalised, and Energinet now owns the entire gas distribution network. The physical planning of the system for the supply of natural gas is governed by the Heat Supply Act. Establishment of new distribution network facilities for natural gas and major alterations to existing facilities requires approval from the relevant city council\(^{20}\) and, in certain cases, the DEA. A storage undertaking is obliged to place storage capacity at the disposal of Energinet, but only to the extent necessary to enable Energinet to maintain physical balance in the network and to ensure security of supply. A storage undertaking must grant access to the storage facilities on the basis of objective, transparent

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17 See also Section III.iii.
18 Act No. 1121 of 3 September 2018.
19 Act No. 287 of 16 April 2018.
20 There are 98 municipalities (city councils).
and non-discriminatory criteria. The Danish market for natural gas was fully liberalised on 1 January 2004, and since then customers have had a right to choose a natural gas supplier. Anybody may in principle establish a natural gas supply undertaking.

Electricity grid undertakings have a monopoly on the distribution in their areas and are governed by the Electricity Supply Act. The transmission system operator (Energinet) is responsible for the general security of supply in Denmark and must ensure the overall balance and quality of the electricity supply system. Also, the operator must ensure players have access to the transmission system on objective, fair and transparent terms. Electricity supply undertakings supplying electricity on commercial terms are generally not governed by the Electricity Supply Act.

iv  Transfers of control and assignments
Natural gas and electricity licences, where applicable, can only be issued to applicants with the necessary expertise and economic capacity. The licence can neither directly nor indirectly be transferred to others without approval by the DEA. A gas distribution network or shares in companies that own distribution networks are generally only allowed to be transferred to the state. In 2016, 2018 and 2019 the Danish state purchased the three large gas distribution networks in Denmark. The Danish state now owns the entire gas distribution network.

Since 1998, Danish competition legislation has been strongly influenced by EU competition law, but the Danish rules are generally stricter than those of the EU in terms of support for free competition.

III  TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES
i  Vertical integration and unbundling
The level of unbundling in Denmark generally exceeds the requirements of the Electricity and Gas Directives. Through the establishment of Energinet, Denmark has secured ownership unbundling of the main transmission grids and the gas distribution network.

In the electricity and natural gas industries, there is a requirement for legal unbundling in relation to the parts of the value chain of monopolistic character. The Natural Gas Supply Act requires a company with a licence for transmission, distribution, storage, LNG business or universal service obligations to conduct only activities allowed under the licence.

As a general rule, the Electricity Supply Act does not allow grid and transmission licences to be issued to the same company. Undertakings producing electricity by means of waste incineration are not allowed to carry out other types of electricity production or trading activities. The requirement for unbundling of activities does, however, not preclude the use in combined waste incineration plants of other types of fuel (e.g., straw, chipped wood or natural gas) together with waste suitable for incineration.

The requirements are supplemented by demands for managerial unbundling in the Electricity Supply Act and in the Natural Gas Supply Act. To prevent conflicts of interest, executives and managers of a distribution undertaking must not directly or indirectly participate in the operation or management of an associated undertaking selling or producing natural gas or electricity, or participate in an associated undertaking that indirectly owns such an undertaking. Members of the board of directors of distribution undertakings must not directly or indirectly participate in the operation or management of associated undertakings selling or producing natural gas or electricity.
ii Transmission/transportation and distribution access

Danish law allows full access on a non-discriminatory basis to the transmission and distribution systems in both the natural gas and electricity sectors.

Natural gas

The transmission network for natural gas is connected to the natural gas transmission networks in Germany and Sweden. The transmission network is connected to the distribution network to which the end users are connected. Both the Danish transmission network and the distribution network are owned by Energinet. There is a general right to use the transmission network against payment of applicable fees. Access can be denied if the transmission undertaking cannot meet the capacity requirements, cannot ensure the quality of the natural gas, cannot ensure security of supply, cannot ensure sufficient quantities of natural gas, or if a natural gas undertaking has severe economic and financial difficulties with fulfilling contracts (including take-or-pay commitments). Access can also be denied if a natural gas undertaking does not comply with the access requirements laid down by the transmission undertaking. Reasons must be given for denial of access, and a denial of access can be brought before the DUR.

Electricity

The transmission grid for electricity is the part of the electricity grid that transports electricity to local grid undertakings, which then distribute the electricity to end users. The transmission grid also transports electricity to and from other countries. The transmission grid is owned and operated by Energinet, which is responsible for the security of supply and the overall balance and quality of the electricity supply system. Energinet is also responsible for the overall planning and development of the transmission system. Energinet must ensure that players have access to the transmission system on objective, fair and transparent terms. The grid undertakings deliver electricity from the transmission grid to individual end users. Each owns and operates a distribution grid within a local supply area. Grid undertakings have a monopoly on the distribution within their area. However, the grid undertakings must ensure that players have access to the grid on objective, fair and transparent terms.

iii Terminalling, processing and treatment

The storage facilities for natural gas are currently situated at two locations in Denmark: Stenlille and Lille Torup. The two gas storage facilities are owned and run by Energinet.

iv Rates

It is a general rule that access to transmission and distribution grids must be provided on the basis of objective, transparent and non-discriminatory criteria. When setting prices, grid undertakings must not discriminate between users. Transmission and grid undertakings must prepare a plan for internal supervision and describing the undertaking’s measures to prevent discriminatory practices. Prices must be based on the undertaking’s costs and a reasonable return on capital invested by the undertaking.

21 See footnote 8, above.
v  Security and technology restrictions

Undertakings that sell oil in Denmark must keep oil reserves in storage ready for emergency use by the Danish state. Denmark’s obligations to maintain such oil storage follow from an EU directive and from rules laid down by the International Energy Authority. The Danish Act on Emergency Oil Supplies\(^\text{22}\) ensures emergency supply in the event of disruptions or threats in the oil sector, including keeping reserves of crude oil and petroleum products, and collecting data on the oil conditions in Denmark. The Danish emergency oil management system is primarily handled by the Danish Central Oil Stockholding Entity, which is an independent organisation set up by the oil companies and appointed by the DEA.

IV  ENERGY MARKETS

i  Development of energy markets

Nord Pool Spot runs a power market in northern Europe and offers both day-ahead and intraday markets; 380 companies from 20 countries trade on the market. Nord Pool Spot is owned by the Nordic and Baltic transmission systems operators (in Denmark, Energinet). In 2018, the group had a total turnover of 524 TWh. The power price is determined by the balance between supply and demand. Factors such as the weather or power plants not producing to their full capacity may have an impact on how much power can be transported through the grid and may therefore influence the price of power.

ii  Energy market rules and regulation

The Minister can decide that oil undertakings must submit information on the conditions of import, export, production, sale, storage and transport, and on other general matters. The Minister can stipulate that undertakings producing or importing oil must sell oil in accordance with international distribution schemes.

The liberalisation of the gas market on 1 January 2004 meant that all natural gas customers would have a free choice of supplier. Any party can establish a natural gas undertaking supplying natural gas, provided that it enters into agreements with the relevant transmission, storage (if needed) and distribution undertakings. An undertaking trading in natural gas can sell its products on market terms. Natural gas suppliers may be licensed as a supply-committed undertaking in areas designated for natural gas pursuant to the Heat Supply Act, with the effect that the undertaking has the right and duty to supply natural gas to all customers within the area that have not used their right to choose an alternative gas supplier. The undertaking may deny supply of natural gas to a customer that does not pay for the deliveries.

Sale and delivery of electricity to end users are made by electricity suppliers, which are either supply-committed undertakings or undertakings supplying electricity on commercial terms. Supply-committed undertakings deliver electricity to consumers who have not exercised their right to choose an alternative supplier.

iii  Contracts for sale of energy

Most power in the Nordic and Baltic region is traded on Nord Pool Spot. Natural gas, on the other hand, is still primarily traded through bilateral contracts, although an increasing

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\(^{22}\) Act No. 354 of 24 April 2012 on Emergency Oil Supplies.
quantity is traded at the market exchange Gaspoint Nordic. In 2017 17,380,709MWh was traded on Gaspoint Nordic. In 2018 this number rose to 25,097,094MWh. Danish energy legislation generally only regulates end-user contracts.

### Market developments

There are a large number of new energy policy initiatives seeking to accelerate the transition to green energy. The four critical focus areas are: energy efficiency, electrification, expansion of renewable energy and research, and development and demonstration.

### RENEWABLE ENERGY AND CONSERVATION

#### Development of renewable energy

Denmark has a long tradition of active energy policy, initiated by the first oil crisis in 1973. When oil prices accelerated in 1973, Denmark was among the OECD countries most dependent on oil in its energy supply, with more than 90 per cent of all energy supply deriving from imported oil. Denmark launched an active energy policy to ensure the supply and enable Denmark to reduce its dependency on imported oil. In combination with oil and gas production from the North Sea, Denmark went from being a net importer of oil in 1973 to being more than self-sufficient in energy from 1997 and beyond.

In the Kyoto period 2008–2012, Denmark committed itself to a greenhouse gas reduction target of 21 per cent. Today, renewables account for more than 40 per cent of Danish electricity consumption and, through expanded offshore wind production and use of biomass, the government expects that renewables will reach 100 per cent of Danish electricity production in 2030. A new political agreement between the government and all the major opposition parties was reached in June 2018. The agreement sets out the following goals for 2030: approximately 55 per cent renewable energy in final energy consumption, 100 per cent of the Danish electricity production to be covered by renewable energy, at least 90 per cent of the district heating consumption to be covered by renewable energy and more than 50 per cent of electricity consumption to be supplied by wind power. These are all goals that will enable Denmark to be a net zero emissions society by 2050 at the latest.

Energy taxes on electricity and oil were introduced in 1977, and since then taxes have been increased several times and have also been extended to coal and natural gas. In 1992, the taxes were supplemented by carbon taxes.

Other means of achieving renewable energy are heat-savings initiatives in buildings, use of renewable energy in buildings, municipal heat planning, energy-efficient electricity and district heat production, and use of renewable energy in electricity and district heat production, plus energy savings and use of renewable energy in industry and transportation.

Wind turbines have been supported politically for many years, including through state subsidies, feed-in tariffs, orders to the electricity utilities to build wind turbines, tenders for offshore wind farms and orders to the municipalities to allocate suitable areas for new onshore wind turbines. Approximately 40–45 per cent of electricity is currently produced by wind turbines (and this is expected to exceed to 50 per cent in 2020).
In 2009, the Promotion of Renewable Energy Act\textsuperscript{23} was launched to promote the production of energy through the use of renewable energy sources, in accordance with climate, environment and macroeconomic considerations, to reduce dependence on fossil fuels, ensure security of supply and reduce carbon emissions and other greenhouse gases.

In 2018 the Danish government and parliament entered into an agreement that allocates 19 billion kroner to investments in renewable energy, 3.5 billion kroner to easing of taxes on electricity and of taxes on electricity for heating purposes, and has the purpose of accelerating the phase-out of coal through a modernisation of the heating sector.

\section*{ii Energy efficiency and conservation}

Denmark has long supported energy efficiency and conservation initiatives, which played an important role in the efforts to free Denmark from dependence on fossil fuels. In the 1976 Energy Plan, energy efficiency was one of two main targets. During the 1970s, a number of acts and initiatives were implemented to support energy efficiency, with a focus on three main areas:

\begin{itemize}
  \item a heat consumption in buildings;
  \item b industrial and process – covering industrial and production-related consumption; and
  \item c appliance and components – covering electrical appliances and components not directly related to industrial use.
\end{itemize}

A number of schemes have also been implemented, designed to promote energy savings in buildings and industry. Major current initiatives include:

\begin{itemize}
  \item a energy and carbon taxes on domestic and public sector energy consumption;
  \item b carbon taxes on industrial consumption;
  \item c carbon emission allowance trading scheme;
  \item d voluntary agreements for industry;
  \item e energy labelling for large and small buildings;
  \item f energy labelling of appliances and lighting;
  \item g norms for energy efficiency and voluntary agreements; and
  \item h reduction of standby consumption.
\end{itemize}

\section*{iii Technological developments}

The Danish strategy for energy-efficient technologies provides a framework for prioritisation and development of research and development efforts to achieve the greatest possible impact by public funds used in the field.

\section*{VI THE YEAR IN REVIEW}

\section*{i The Energy Agreement of 29 June 2018}

The Danish government and all the parties of the parliament entered into an agreement that set a number of objectives to making Denmark a net zero emissions society by 2050. The main goal of the agreement is that by 2030, 55 per cent of Danish energy consumption will stem from renewable energy. This will be achieved by reaching a total share of renewable energy in electricity consumption of 100 per cent and for district heating consumption it is

\textsuperscript{23} Now Act No. 53 of 18 January 2019 on the Promotion of Renewable Energy.
expected to exceed 90 per cent, though it has not been possible to ascertain this percentage precisely with the new initiatives. The agreement obligates the signatory parties to building three offshore wind farms with a capacity between 800MW and 1,000MW each. The first of these three offshore wind farms will be put out to tender in 2019. The tender will be on both the offshore wind farm and the grid connection.

ii New revenue framework for electrical grid companies

On 8 April 2019, the Danish Utility Regulator reached a decision in regards to the individual efficiency requirements of the electrical grid companies. The Danish Utility Regulator has decided to use a new benchmarking method even though it has been widely criticised by the industry. The method of benchmarking was criticised for not being robust and for not being able to identify true and realistic economic efficiency potential.

iii Consolidation of gas distribution networks

In March 2019, the state-owned entity Energinet acquired the entire gas distribution network. In 2016, Energinet bought the gas distribution network in the southern part of Jutland and the western part of Zealand from DONG (now: Ørsted). The 1 May 2018 Energinet acquired the gas distribution network on Funen from NGF Nature Energy Distribution, and in March 2019 Energinet acquired HMN GasNet, the gas distribution network in the rest of Denmark. The state will then, through Energinet, own the entire gas transmission and distribution network in Denmark.

iv Five applications in the eighth licensing round for the exploration and exploitation of oil and gas in the Danish North Sea

The eighth licensing round ended the 1 February 2019. The five applications for exploration and exploitation of oil and gas in the Danish North Sea came from four different corporations; Ardent Oil Ltd, Lundin Norway AS, MOL Dania ApS, and Total E&P Danmark A/S. The Danish Energy Agency expects that the applications will be processed in summer 2019. The ninth licensing round is expected to commence in 2020.

VII CONCLUSIONS AND OUTLOOK

Denmark is continuously increasing its focus on renewable energy with the aim of being an international leader in the area and ensuring self-sufficiency. There is a large focus on cost-effectiveness and ensuring cheap energy for consumers while maintaining incentives for new investments in the sector.
Chapter 8

FRANCE

Fabrice Fages and Myria Saarinen

I OVERVIEW

In France, the energy market has undergone a progressive liberalisation as a result of the European plan to establish a unique energy market that would end national monopolies. This has naturally led to an important legislative and regulatory change, which was codified by an Order dated 9 May 2011 and which created the legislative part of the French Energy Code. This Code sets out provisions relating to electricity, gas, renewable energy, hydropower, oil and both heating and cooling networks.

This chapter will focus mainly on electricity and gas markets since they have been the main energy markets affected by such changes. It should, however, be underlined that the other sources of energy are also subject to specific regulation.

As a matter of history, after the Second World War, to rebuild the infrastructure and the network, the French authorities decided to grant a state monopoly to Electricité de France (EDF) and Gaz de France (GDF, now Engie) with regard to the production, transportation and distribution of electricity and gas respectively. This situation remained substantially unchanged for half a century until France had to implement into its national law two Directives dated 1996 and 1998 adopted by the European Commission to promote an effective and efficient internal energy market, open to competition. These directives were progressively transposed into French law as of 2000 and initiated the beginning of the liberalisation, although initially only large industrial consumers could benefit from this system.

Further opening of the energy market occurred several years later with the transposition into French law of new Directives dated 2003, which aimed to make this opening available to all professional consumers by 1 July 2004, and to all consumers, including residential or customers, by 1 July 2007.

1 Fabrice Fages and Myria Saarinen are partners at Latham & Watkins AARPI. This chapter was written with the assistance of Floriane Cruchet, an associate at the firm, and Fanny Millet, a law clerk.
3 Law No. 46-628 of 8 April 1946 concerning the nationalisation of electricity and gas, repealed by Law No. 2004-803.
Although significant progress had been made, the European Commission adopted the Third Energy Package to further liberalise the energy market, which included two new directives replacing the former electricity and gas directives. These directives were transposed into French law on 7 December 2010 by a new law commonly referred to as ‘Law NOME’, which led to the removal of several obstacles to the development of competition in the French electricity market. Greater price liberalisation for industrial and residential customers has been achieved, notably by requiring EDF to sell a substantial part of its existing nuclear facilities to alternative suppliers at a regulated price, from January 2011 to 2025, so as to allow alternative suppliers to compete fairly with the historical supplier. Finally, France launched an energy transition with the adoption of Law No. 2015-992 on 17 August 2015. This law established new rules supporting renewable energy production and stated ambitious objectives that were specified by the multi-annual energy programming for the period 2016–2023.

II REGULATION

i The regulators

Compliance with the new energy market regulations is mainly controlled by the Commission of Regulation of Energy (CRE), the sectoral regulator, which was created by the Law dated 10 February 2000. Its overall mission is to ‘contribute to the proper operation of the electricity and natural gas markets, to the benefit of final customers’.

The CRE is principally in charge of:

a powers of decision, approval or authorisation (system operators, contributions to the public electricity sector, etc.);

b dispute settlement and sanctions relative to access to the electricity and gas networks;

c powers of proposal (tariffs for the use of public electricity grids, contributions to public electricity services, etc.);

d information and investigative powers with stakeholders;

e advisory powers (tariffs, regulated access to incumbent nuclear electricity, etc.); and

f additional powers (processing of tenders for electricity generation, etc.).

The CoRDIs committee, which is an independent body of the CRE, acts in matters where the CRE has competence with regard to sanctions, and settles disputes related to the access and use of public electricity grids and natural gas networks.

Further, an energy ombudsman has been put in place whose role is to provide consumers with all necessary information concerning their rights, current legislation and the means of dispute settlement available to them in the event of a dispute.

In addition, the French Competition Authority (FCA) has the power to prevent and sanction anticompetitive practices in any economic sector, including electricity and

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6 Law No. 2010-1488 of 7 December 2010 establishing a new organisation of the electricity market.

7 Articles L131-1 to L135-16 of the French Energy Code.
gas. It must inform the CRE when seized of any matter that would fall under the CRE’s jurisdiction. The FCA must also notify the CRE of any abuse of a dominant position or any anticompetitive practice in the gas or electricity sector.\(^8\)

Finally, the Higher Energy Council is a body established by the Ministry of Energy that is composed of several members including Members of Parliament. Its main purpose is to advise on national energy policy. The Council is consulted on regulatory acts relative to such policy and on electricity and gas market-related decisions.

ii Regulated activities

The energy market is composed of four main areas of activity: production (generation), transmission, distribution and supply (commercialisation). Under the previous regime, which was applicable until 2000, these four activities were carried out by EDF and GDF, which self-regulated the monopoly.

There have now been greater strides towards liberalisation as production and supply are open to competition. Transmission and distribution are still, however, public service activities supervised by the CRE. Where, to guarantee this public service mandate, a legal and financial separation between such activities has taken place,\(^9\) transmission is performed by GRT (gas) and RTE (electricity), and distribution is performed by GRDF (gas) and ERDF (electricity) or local distribution companies.\(^10\)

More generally, some activities, such as the exploitation of electricity production facilities, require an administrative authorisation when the installed power of the facility exceeds a certain threshold, with different thresholds for different types of facilities. Decree No. 2016-687 of 27 May 2016, for example, provides that the installation of an electricity generating facility using renewable energy will require an administrative authorisation if its installed power exceeds 50MW.\(^11\) The previous threshold ranged from 12–30MW. The authorisation is delivered by the Minister of Energy according to specific considerations such as security, energy efficiency, technical and economic capacities of the applicant.\(^12\) Similarly, gas exploration also requires an administrative authorisation or a concession, which is granted subject to a public enquiry and a tender procedure.\(^13\)

iii Ownership and market access restrictions

Although the French Energy Code does not provide for any restriction or requirement in relation to the acquisition of assets in the energy sector by foreign companies or individuals, it clearly states that the French state must hold at least 70 per cent of the capital and voting rights of EDF and one third of Engie\(^14\) (to protect the French national interest, the state may benefit from specific shares within the capital of Engie).\(^15\)

\(^8\) Article L134-16 of the French Energy Code.
\(^9\) Law No. 2004-803 of 9 August 2004 concerning the electricity and gas public service; Law NOME.
\(^10\) Local distribution companies are defined by Article L111-54 of the French Energy Code.
\(^11\) Articles R311-1 et seq. of the French Energy Code.
\(^12\) Article L311-5 of the French Energy Code.
\(^13\) Articles L131-1, L132-3 and L132-4 of the French Mining Code.
iv Transfers of control and assignments

Any merger or any change in control over businesses in the energy sector, or any acquisition of utility assets, must be notified and supervised by the FCA if the following three cumulative conditions are met:

a. worldwide aggregate turnover of all the parties to the concentration exceeds €150 million;

b. turnover in France of each or at least two parties concerned exceeds €50 million; and

c. the transaction does not meet the EC Merger Regulation thresholds.

The examination process by the FCA is twofold. In Stage I (which takes up to 40 working days), the FCA has 25 working days to examine the transaction starting from the date when a complete notification is received. When remedies are proposed to the FCA, this period is extended by up to 15 working days. At the end of this period, the FCA can clear the transaction, with or without remedies or proceed to an in-depth investigation. In the absence of any decision, the transaction is tacitly cleared.

Stage II takes between 65 and 85 working days. If serious doubts remain as to the competitive impact of the transaction, the FCA proceeds with an in-depth investigation. During Stage II, if the transaction relates to a regulated area, the FCA may request a non-binding opinion from the relevant regulator (e.g., the CRE). At the end of Stage II, the FCA can either clear the transaction with or without remedies or prohibit the transaction.

The FCA’s authorisations for acquisitions may be subject to conditions.

In addition, the French government issued Decree No. 2014-479 dated 14 May 2014 expanding the list of strategic sectors, including the energy sector, in which foreign investments in France require the prior authorisation of the French Minister of the Economy.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Vertical integration is the process in which different aspects of the market are controlled by a common company or entity. Prior to the deregulation of the energy industry, French energy companies were largely vertically integrated, which created potential conflicts of interest and monopoly situations.

The European Commission issued Directives 2003/54/EC and 2003/55/EC principally to ensure efficient and non-discriminatory network access, ensure free choice of suppliers by consumers, and encourage investment. This legislation was transposed into the French system by a Law dated 9 August 2004, which provided for a legal unbundling of regulated activities (distribution and transmission) from non-regulated activities (production and supply). After

17 See, for example, the decision of the FCA dated 7 February 2012: the FCA made its authorisation of the acquisition of Enerest by Electricité de Strasbourg conditional on a number of commitments designed to resolve competitions concerns, such as the commitment not to make offers for two energies that include at least one component at a regulated tariff. This commitment, the effectiveness of which is to be guaranteed by separating the sales teams responsible for electricity and gas at Electricité de Strasbourg, notably eliminates any risk of the company using its business of supplying energy at regulated tariffs as a tactic to win customers on the open market.
18 Article L151-3 of the French Monetary Code.
an inquiry launched in 2005 by the European Commission, however, serious shortcomings in the electricity and gas markets were identified, including an inadequate current level of unbundling between network and supply interests deemed to have negative effects on the market and investment. Consequently, under Directives 2009/72/EC and 2009/73/EC, priority was given to achieving effective unbundling of network and supply activities.

As explained above, these directives were transposed into French law so that the transmission and distribution system operators would be legally and fully unbundled companies. Accordingly, transmission and distribution system operators must be equipped with all the necessary human, technical, physical and financial resources to fulfil their obligations under French law and, in particular, they must own the assets necessary for their activity.

ii Transmission/transportation and distribution access

Non-discriminatory and fair access to transmission and distribution networks for gas and electricity are at the core of the free market approach. Any discrimination, prevention of new participants from entering the market, and restriction to fair competition in favour of the consumer, is subject to sanctions issued by the CoRDiS committee.

Among the measures guaranteeing such non-discriminatory and fair access, it should be noted that any refusal to enter into an agreement must be justified and notified to the applicant, as well as to the CRE, specifying that any refusal is justified by objective, transparent and non-discriminatory reasons. Furthermore, any transport or distribution system operator serving more than 100,000 clients must draw up a code of conduct to ensure compliance with the non-discrimination principle.

Finally, the CRE must publish an annual report concerning compliance with the code of conduct and a summary of its assessment of the independence of the transport or distribution system operators.

iii Terminalling, processing and treatment

There are currently three natural gas terminals in France: Fos Tonkin and Fos Cavanou, both near Marseille, and Montoir-de-Bretagne, near Saint-Nazaire. Tariffs for the use of natural gas terminals, which are regulated, are set by the CRE.

The operation of storage facilities is subject to a concession. The storage of natural gas must ensure (1) the proper operation and balancing of systems connected to underground natural gas storage facilities, (2) the direct or indirect meeting of domestic clients’ needs, and (3) compliance with public service obligations. Access to storage is guaranteed; the operators

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20 Articles L111-91 et seq. of the French Energy Code.
21 Articles L111-93 (for electricity) and L111-102 et seq. (for gas) of the French Energy Code.
24 Articles L211-2 and L 231-1 of the French Mining Code.
of underground storage facilities are free to negotiate the terms of their offers with their customers, with the latter being able to rely on objective, transparent and non-discriminatory criteria.26

iv Rates
Access tariffs to networks aim at guaranteeing transparent and non-discriminatory access to public networks. These fees are calculated in a way that cover all costs supported by the system operators (costs arising from their public service duties, the research and development needed to increase the transmission capacity, and the grid connection).

The methodology used to establish access tariffs to the network is set up by the CRE. In addition to fixing the rates, the CRE grants appropriate incentives for transmission and distribution system operators over both the short and long term to increase efficiency, foster market integration and security of supply and support related research activities.27

v Security and technology restrictions
Security of electricity and gas supply is an essential public service obligation.28 The Ministers of Energy and Economy must ensure the fulfilment of this public service mission mainly by EDF, GDF, RTE, GRT, ERDF, GRDF and local distribution companies. In the event of a serious energy shortage, the government may subject energy resources to control and allocation.29 Such measures mainly concern production, imports, exports, storage, acquisition, and transportation. In the event of a serious energy market crisis, or threat to the safety or security of the networks and of people, the Minister of Energy may take protective measures to grant or suspend licences for the operation of power generating facilities.30 In times of war or serious international tension, the government may regulate or even suspend oil import or export completely.31

In addition, in order to ensure energy autonomy, France has put in place a capacity market that entered into force on 1 January 2017. The capacity mechanism aims at encouraging demand management, especially during peak hours, via the purchase or sale of certificates depending on whether energy consumption needs are met.

IV ENERGY MARKETS
i Development of energy markets
The sale of energy takes place within either the wholesale market or the retail market. The wholesale market is the market in which electricity and gas are traded (bought and sold) before delivery in the network to final customers (individuals or companies), whereas the retail market concerns the final clients who may freely choose their suppliers (eligible customers).32

The participants of the wholesale market are:

a producers who trade and sell their production;

27 Articles L341-3 (electricity), L452-2 and L452-3 (gas) of the French Energy Code.
28 Articles L121-1 (electricity) and L121-32 (gas) of the French Energy Code.
29 Article L143-1 of the French Energy Code.
30 Article L143-4 of the French Energy Code.
31 Article L143-7 of the French Energy Code.
32 Article L331-1 of the French Energy Code.
suppliers who trade and supply gas or electricity before selling gas or electricity to the final client; and
brokers or traders who purchase gas or electricity for resale and thus favour market liquidity.

As most of the activity in the wholesale gas market and wholesale electricity market takes place over the counter, through direct transactions or through intermediaries (brokers and trading platforms), the opening of these markets to competition has led to the emergence of organised markets, namely trading platforms (such as Epex Spot France or EEX Power Derivatives France).

ii Energy market rules and regulation

Even if the supply of energy is open to competition, it is still subject to certain requirements and monitoring. First, the sale of electricity or gas is subject to governmental approval. Indeed, suppliers willing to purchase electricity or gas to sell them to consumers need an administrative authorisation that is delivered subject to their technical, economic and financial capacities, and according to their project’s compatibility with the security of supply obligation.

Second, each transaction performed on the French market that would involve the participation of a producer, broker or energy supplier, must be monitored by the CRE, regardless of the trading method (two-way trades, with or without a broker or transactions within organised markets).

Third, free competition is limited with respect to pricing practices since, in certain circumstances, ‘regulated tariffs’ may be chosen within the electricity market by customers having contracted for less than 36kVA. However, because of the European Commission’s unhappiness, especially with the electricity retail market and the dominant position exercised by EDF, Law NOEM ended ‘regulated tariffs’ for customers having contracted for more than 36kVA by 31 December 2015. Furthermore, in the gas market, the suppression of gas-regulated tariffs for all non-domestic consumers entered into force on 1 January 2016. The removal of these tariffs has induced more competition, with new participants entering the wholesale market, even though price differences remain small.

Finally, the Contribution to the Public Electricity Service, which has been funded since 2016 by the domestic consumption tax on electricity for end users, has been created to compensate public service charges assigned mainly to EDF, such as support schemes for renewable energy or social electricity tariffs.

iii Contracts for sale of energy

The legal unbundling between the production and the distribution activities imposed by the energy market creates several inconveniences for the consumer who, as a result, gets an increasing number of contractors, the responsibilities of which are diminished.

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33 CRE, Electricity and gas market report, fourth quarter of 2011.
34 Articles L333-1 (electricity), L443-1 and L443-2 (gas) of the French Energy Code.
36 Article L337-7 of the French Energy Code.
To prevent this, the Law dated 7 December 2006, completed by the Law NOME, created a new section in the French Consumer Code entitled ‘electricity supply or natural gas contracts’, the provisions of which apply to contracts concluded by consumers and professionals for less than 36kVA (electricity) or less than 30,000kW (gas).

The energy supplier ‘must give the client an opportunity to sign a single contract dealing with both the supply and the distribution of electricity or natural gas’. This contract, which should at least last for one year, thus creates a tripartite relationship between the supplier, the distributor and the consumer, even though the supplier often remains the consumer’s main interlocutor.

The supplier must mention several specific provisions both in the offer and the contract. Failure to do so is subject to sanctions. The consumer can rescind the energy supply contract at any time if it plans on changing supplier. Professionals are not entitled to ask the consumer for any other costs than those incurred by the rescission, provided that these costs were mentioned in the offer.

iv Market developments

Market developments have taken place in different areas, and in particular on the cost of electricity with the Law NOME and on renewable energies with the Law on energy transition. Moreover, the renewal procedure of hydraulic concessions has been launched and is ongoing, while the regime of hydraulic concessions has been reformed, notably regarding the procedure applicable to the granting of such concessions.

Finally, the implementation of legal frameworks for the self-consumption of electricity and for closed energy distribution systems, such as the one set up by Order No. 2016-1725 of 15 December 2016 subjecting the operation of these systems to the issuance of an administrative licence, might enhance the development of local energy markets for the upcoming years.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

In July 2007, the French government launched the Grenelle Environment Forum, a major national consultation that led to the emergence of priority targets in terms of controlling energy consumption and promoting renewable energies. This forum led to the enactment of two ‘Grenelle Laws’, on 3 August 2009 (Grenelle I) and 12 July 2010 (Grenelle II) respectively, aiming at promoting environmental objectives such as the increase of the share of renewable energy to at least 23 per cent of final energy consumption before 2020, in accordance with European Union Directive 2009/28/EC. These laws were codified in a

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39 Articles L224-1 to L224-5 of the French Consumer Code.
40 Article L224-8 of the French Consumer Code.
44 Law No. 2009-967 of 3 August 2009 relating to the implementation of the Grenelle Environment Forum; Law No. 2010-788 of 12 July 2010 relating to national commitment for the environment.
separate section dedicated to renewable energy in the French Energy Code. More recently, Law No. 2015-992 of 17 August 2015 on energy transition and its several implementing decrees substantially modified the applicable legal framework on renewable energy.

To enhance the development of renewable energies, public authorities can use two economic instruments: (1) the purchase obligation, requiring EDF to buy electricity produced from renewable sources, for a regulated tariff over a long period, which can be changed and is slightly higher than the market price; and (2) the supplementary remuneration, which provides that EDF is obliged to enter into a contract for the purchase of electricity – whose duration shall not exceed 20 years – with renewable energy producers, according to which an additional remuneration shall be paid to them.

The regime, eligibility for and articulation of these two schemes were later substantially reformed by three Decrees:

\( a \) Decree No. 2016-691 of 28 May 2016 defining the list and characteristics of the installations eligible to one or the other of the support mechanisms;

\( b \) Decree No. 2016-690 of 28 May 2016 setting out the terms and conditions of the assignment of the purchase obligation contract; and

\( c \) Decree No. 2016-682 of 27 May 2016 on the purchase obligation and on the supplementary remuneration.

\[ \text{ii Energy efficiency and conservation} \]

To achieve a 20 per cent increase in energy efficiency, in accordance with the climate and energy package, on 25 October 2012 the European Union adopted Directive 2012/27/EU on energy efficiency. It lays down rules designed to remove barriers in the energy market and to overcome market failures that impede efficiency in the supply and use of energy, and provides for the establishment of indicative national energy-efficiency targets for 2020.

The transposition of this directive into French law led to the adoption of several measures intended to improve energy efficiency, such as:

\( a \) the creation of an obligation for companies to be subject to an energy audit every four years; 47

\( b \) the submission by France of its report on its efficiency energy target to the European Commission on 24 April 2014; and

\( c \) the establishment of a requirement for public purchasers to buy products and services and to buy or rent buildings that have a high energy efficiency. 48

Law No. 2017-1839, adopted on 30 December 2017, brought to a definite end the search and exploitation of hydrocarbons. The government’s principal aim being the progressive phase-out of the hydrocarbon production on the French territory by 2040, the law provides that no new research permit for hydrocarbons will be granted by the government.

\[ \text{iii Technological developments} \]

Directive 2012/27/EU also includes several provisions related to the development of smart grids and smart meters, the aim of which is to reduce bills by paying what was really consumed

and by understanding consumption patterns better. The development of smart grids is based on the idea that it improves energy efficiency and better integrates renewable energy resources in the network.

The development of smart grids has also been decided in France. Indeed, a Decree dated 31 August 2010 provided that new connection points must be equipped with smart meters from 1 January 2012 and provided for a test run or pilot for such equipment.

Following the governmental announcement that 35 million smart meters will be provided to electricity customers throughout the country by 2020, the deployment started in December 2015.

VI THE YEAR IN REVIEW

The year 2018 and the beginning of 2019 were characterised by several developments in the energy sector.

i Announcement of the roadmap for the energy strategy in France over the next few years (2019–2023)

In the course of 2018, the draft of the new decree setting forth the multi-annual energy programmes was publicly debated and submitted to several consultative bodies. The decree is expected to be enacted by mid-2019. Since the government’s aim is to reduce final energy consumption by 7 per cent in 2023 (compared to 2012), the measures suggested:

a develop the production of energy from renewable sources, in particular by launching competitive tendering procedures for onshore wind power (two calls for tenders per year) and photovoltaics (two to three calls for tender per year);

b shut down the last four coal-fired power plants by 2022;

c create more than 100,000 public electric charging points and encourage the replacement of dirty vehicles (vehicle change aid);

d redefine the objectives and purposes of energy efficiency certificates;

e implement an energy renovation plan for public buildings; and

f shut down two Fessenheim nuclear reactors by 2020 (a goal increased to 14 reactors by 2035).

ii Adoption of new measures concerning offshore wind turbines and geothermal energy

Law No. 2018-727 dated 10 August 2018 provides for three main developments in relation with offshore windfarms project.

Firstly, prior to the launch of a call for tender for the building and the operation of an offshore windfarm, the Minister of Energy shall consult the National Commission for Public Debate (CNDP), which will determine under which conditions the local population will be consulted on certain parameters of the project, including the contemplated locations of the project. As a result, the operator selected through the call for tender will not need to later submit its project to the consultation of the CNDP.49

49 Article L121-8 of the French Environment Code.
Secondly, a new pecuniary sanction has been implemented in the event that the selected operator does not carry out the project under the conditions set forth by the law or the tender. 50

Thirdly, the reform also authorises the Minister of Energy to request from the selected operator to improve their offer, in particular by reducing the tariff agreed upon in the course of the tender. 51 This provision is applicable to calls for tenders launched prior to 1 January 2015 and where no contract for the purchase of electricity has been concluded with the selected operator so far. This change has been justified by the technological developments in this sector.

iii Closing of the CNIL’s procedure against Direct Energie in relation to the processing of users personal data through the Linky smart meter

On 5 March 2018, the CNIL issued a formal notice as per which it required Direct Energie to obtain from its customers, within three months, a prior consent for the collection through the Linky smart meter of data concerning their energy consumption every 30 minutes and their daily energy consumption. 52 The collection of these data was not legally required nor justified by performance of the contract. In addition, the customers were not able to specifically consent to the processing of these data and were not sufficiently informed on the purpose of this processing.

On 24 October 2018, the CNIL formally closed the procedure after having noted that Direct Energie complied with the applicable data protection laws requirement by enabling its customers to choose if they allow Direct Energie to process the above-mentioned data that, by default, will not be collected. 53

iv Sanctions of fraud in relation to energy efficiency certificates

Created under Law No. 2005-781 of 13 July 2005 setting forth the guidelines for energy strategy, the energy efficiency certificates (EEC) are tools that contribute to reducing energy consumption, particularly through energy renovation work. The scheme, which entered its fourth period of application in 2018, targets energy providers and oil distributors by requiring them to meet by the end of specified period of time a determined volume of EECs. These EECs can be directly granted to the target on the basis of energy saving efforts (e.g., renovation of facilities, action of energy saving toward end users) or be purchased on a market to other players. As per a report published in 2016, Tracfin alerted the authorities on the existence of significant documentary fraud at the EEC issuance phase that leads the administrative body in charge of EEC to increase its controls. In this context, the administration pronounced a significant pecuniary sanction of €11.288,850 million against a company suspected of fraud. 54

52 CNIL Decision No. 2018-007 of 5 March 2018.
53 CNIL Decision of 24 October 2018.
54 Sanction decision of the Minister of Energy dated 15 June 2018.
v Publication of a draft decree regarding the regulated access to historic nuclear electricity

The access to historic nuclear electricity (ARENH) system was created in the context of the liberalisation of the electricity market by Law NOME and allows electricity suppliers to have access to nuclear energy under conditions equivalent to those of the historic provider EDF. The system is now in high demand due to the increase of the electricity price on the wholesale market and the larger part of the market liberalised.

The CRE published a report on January 2018 discussing the efficiency of this system. On the basis of this report, the Ministry of the Energy prepared a draft decree submitted to the CRE that issued a favourable opinion. The draft decree aimed, on the one hand, to abolish the ARENH mid-year stop-shop and, on the other hand, to establish a mechanism for gradually subscribing to ARENH volumes over the year, composed of three stop-shops with subscription thresholds. The CRE considered that the subscription thresholds should be easily adjustable in order to reflect the demand.

As of April 2019, no clear timeframe has been set for the enactment of this decree.

vi Discussions of a draft energy law expected this summer before the parliament

A draft energy law is under preparation by the government and is expected to be submitted to the parliament by mid-2019. The draft has not been made public yet and limited information is available to date. On 20 February 2019, the Economic, Social and Environmental Council issued a draft opinion on Article 1 of the draft law and reveals that the government intends to revise several objectives set forth in the Law on Energy Transition dated 17 August 2015 (e.g., the replacement of the division of greenhouse gas emissions by four by 2050 with a more general objective of ‘carbon neutrality’, acceleration of the reduction in fossil fuel consumption by setting a reduction target of 40 per cent by 2030, compared to 30 per cent previously, reduction of the total energy savings to 17 per cent from 20 per cent by 2030 and postponement to 2035 (instead of 2025) of the 50 per cent reduction of nuclear's part in the electricity production.

VII CONCLUSIONS AND OUTLOOK

Since 2007, the liberalisation of the energy market and the energy transition continue together step by step. While historically France is strongly committed to a public energy service, a huge step towards liberalisation and energy transition has been achieved in the past few years, notably so with the end of regulated tariffs and the adoption of the Law on Energy Transition on 17 August 2015, which aims at developing the role of renewable energies.

Furthermore, the implementation of President Emmanuel Macron’s energy programme will have to be followed. Emmanuel Macron thus notably intends to close all coal-fired power plants within five years, to fix a bottom carbon price for the European Union, to double the capacity of wind and solar energy production and to maintain the prohibition of shale gas exploration and the objective of reducing the part of nuclear energy.

Finally, the amendment and the adoption by the European Parliament and Council of the European Commission’s Fourth Energy Package and its transposition and implementation by France will have to be closely monitored. Containing proposals for no less than four Regulations and four Directives, the EC’s Fourth Energy Package may well have an impact on the French regulation of the energy market.
OVERVIEW

The German energy sector continues to evolve dynamically. As Germany is likely to miss its 2020 carbon dioxide emission reduction goals, the government plans to intensify its efforts to pursue the reform of the German energy market (the ‘energy transition’), meaning a shift of electricity generation to renewable energies and a substantial reduction of carbon dioxide emissions adding to the phase-out of nuclear energy. In particular, the share of renewable energy sources in the power generation mix shall be increased to 65 per cent by 2030. However, the side effects of these ambitious targets have resulted in rising costs for the support of renewable energies, the need for considerable network expansion and unintended effects on the viability of conventional generation capacities. At the same time, the large German utilities are adapting their business models to the changing market conditions.

REGULATION

The responsibility for the energy transition, including climate change, is mainly concentrated at the Federal Ministry for Economic Affairs and Energy (BMWi). The main national regulatory authority is the Federal Network Agency for Electricity, Gas, Telecommunications, Post and Railway (BNetzA) under the authority of the BMWi. BNetzA is responsible for the regulation of gas and electricity networks with at least 100,000 grid customers or networks that extend beyond the territory of an individual state. BNetzA also plays a key role in planning and approving large energy network extension measures according to the Grid Extension Acceleration Act. At regional level, the regulatory authorities of the 16 German states are in charge of the regulation of the smaller networks, in particular distribution networks. The regulatory authorities monitor the compliance of network operators with applicable law and determine the general market rules for transport of electricity and gas. Their duties include the supervision of non-discriminatory network access and determination of the grid operators’ individual revenue caps, and they also ensure that grid operators comply with unbundling rules and with their system security obligations.

The Federal Cartel Office (BKartA) has jurisdiction to apply competition law to the non-network-related parts of the energy supply chain. The BKartA is also in charge of merger control.

1 Thomas Schulz is a partner, and Julia Sack and Ruth Losch are lawyers at Linklaters LLP.
Both the regulatory authorities and the BKartA have wide-ranging powers of enforcement, such as refusal of permits, issue of prohibition orders and imposition of fines.

Since 2013, a market transparency unit at the BKartA has been overseeing and publishing fuel prices in order to increase transparency and competition in these markets. Since 2015, a parallel market transparency unit at BNetzA has been supervising the wholesale trade in electricity and gas markets.

Sources of law
The key source of legislation is the Energy Industry Act (EnWG) which sets out the main regulation of the German energy market including unbundling requirements, grid operation, energy supply, grid concessions, regulators and legal protection. A number of ordinances set out further details, such as the Incentive Regulation Ordinance and the Electricity and Gas Grid Fee and Grid Access Ordinances. The Renewable Energies Act (EEG) sets out the priority network access and remuneration for the generation of electricity from renewable sources; since 2017 it is supplemented by the Offshore Wind Energy Act. The support for co-generation power plants is regulated in the Co-Generation Act.

Another important source of law are the administrative decisions of BNetzA, addressed to individual parties or to groups of network operators. BNetzA also issues general guidelines addressed to the public and interpreting energy sector legislation. The guidelines are not legally binding. However, market participants usually respect them as they form the basis of BNetzA’s decision-making.

ii Regulated activities

Network operation
Operators of distribution and transmission networks must obtain a grid operation permit confirming their personal, technical and economic capability and reliability to ensure the long-term operation of the network. The permit has to be issued by the competent regulatory authorities of the federal states within six months of the authority having the complete application files at its disposal.

In addition, transmission system operators (TSOs) require certification by BNetzA confirming their compliance with unbundling regulation. Before taking a final decision, BNetzA has to submit its draft decision to the European Commission and must take utmost account of the European Commission's statement.

When using public roads, network operators must enter into concession agreements with the municipality owning the roads. Such concession agreements have to be tendered by the municipalities every 20 years in a non-discriminatory procedure without the possibility of unduly favouring their own utilities.

Generation and supply
The construction of power generation facilities requires a permit under the Federal Immission Control Act. The construction and operation of nuclear power plants requires a special permit under the Nuclear Energy Act. As the German government decided to phase out nuclear energy by 2022, commercial nuclear power plants will no longer be authorised. In January 2019, the coal commission, a group of experts convened by the government, proposed phasing out electricity generation from coal by 2038. Thus, it is expected that no new coal-fired power plants will be authorised.
Besides, operators of power generation facilities with a capacity of 10MW or more have to inform the responsible TSO and BNetzA of their intention to shut down a facility at least 12 months before the planned decommissioning. Facilities with a capacity of 50MW or more may not be decommissioned for a maximum period of 24 months if the facility has been designated by the responsible TSO and BNetzA as relevant for system security. In this case, the operator is entitled to reasonable compensation for the necessary maintenance expenses.

Energy supply companies delivering energy to end consumers must notify the regulatory authority of the commencement and of the discontinuance of their supply activities, including proof of sufficient resources and reliability.

Other than already mentioned, the supply or trading of energy does not require any specific licences under energy regulation provisions.

iii Ownership and market access restrictions

If a TSO or its owner is controlled by one or more persons from a country that is not a member of the European Union or of the European Economic Area, the grid operator will only be certified by BNetzA if in addition to compliance with the unbundling rules the BMWi confirms that the certification does not endanger the security of the electricity and gas supply of Germany or of the EU.

Under general foreign investment rules, the BMWi may prohibit on the grounds of public policy or national security the acquisition by a non-EU or non-EEA investor of a participation of 25 per cent or more in a German company or asset. For certain critical infrastructures, in December 2018 the threshold was lowered to 10 per cent. In the energy sector, this relates to infrastructures that supply 500,000 persons or more with electricity, gas, fuel, heating oil or district heating.

iv Transfers of control and assignments

The transfer of regulated assets (i.e., network assets) is not subject to any sector-specific restrictions. However, network operators have to inform the regulatory authority about transfers, mergers or the splitting of grid assets. In the case of a transfer of network assets, part of the revenue cap is transferred with the assets.

The acquirer of transmission assets must comply with the unbundling rules. TSOs have to inform BNetzA of any intended transactions that may require a reassessment of their certification, particularly in the case of a planned takeover or participation by an investor from outside the EU or EEA.

Any transfer of control or decisive influence must be notified for merger clearance to the BKartA or to the European Commission if certain thresholds are exceeded. A merger will be cleared if it does not significantly impede effective competition, in particular by creating or strengthening a dominant position. The BKartA decides within one month of notification or, if an in-depth investigation is initiated, within an additional four-month period. The European Commission has a maximum of 135 working days in which to carry out an in-depth investigation to review a merger (maximum of 160 working days if remedies are offered).
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

In implementing the EU’s Third Energy Package, the EnWG provides for different unbundling regimes for TSOs and distribution system operators (DSOs).

TSOs

As of 3 September 2009, the German transmission networks were all owned by vertically integrated energy supply undertakings (VIUs); the TSOs could choose between three unbundling models: ownership unbundling, the independent system operator model (ITO) and the independent transmission operator model.

Most of the TSOs have opted for the ITO-model and some for ownership unbundling. Following several competition law procedures initiated by the European Commission, and owing to the increased regulation of grid assets, three of the four major German VIUs (E.ON, RWE and Vattenfall) divested their electricity and gas TSOs. This resulted in foreign TSOs and financial investors, such as infrastructure funds, entering the German transmission market.

Regarding the ITO model, the German definition of a VIU in the view of the European Commission excludes activities outside the EU. Furthermore, the independence of the ITO’s staff and management was not sufficiently guaranteed. The European Commission has therefore filed a complaint with the European Court of Justice (C-718/18).

With respect to the ownership unbundling model, BNetzA holds the view that a person controlling electricity or gas production, generation or supply activities may at the same time hold a minority participation in a TSO of up to 25 per cent, provided that this participation does not confer significant minority rights. This is evaluated on a case-by-case basis.

The European Commission has in the meantime recognised that a TSO may be certified as ownership unbundled despite having a shareholder with a participation in generation, production or supply activities if it can prove that no conflict of interest exists. This will be examined on a case-by-case basis, taking into account in particular the geographic location of the transmission activities and the generation, production or supply activities concerned, the value and the nature of the participations in these activities, as well as their size and market share.

DSOs and gas storage operators

Unbundling requirements for DSOs are less strict. DSOs with at least 100,000 grid customers and gas storage system operators must be legally and operationally unbundled from the VIU. DSOs are required to ensure that their communication and branding do not create confusion with regard to the supply branch of the VIU.

At the level of the DSOs there remains a large degree of vertical integration. DSOs typically belong to municipal utilities or to one of the incumbent energy suppliers.

ii Transmission/transportation and distribution access

Connection to networks and network access is regulated. Network operators have to ensure a reasonable, non-discriminatory and transparent connection and access to their grids for all third parties, including extension of the network if required and reasonable (regulated third-party access). By way of exception, priority will be given to network connection and access of operators of renewable energy facilities.

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Costs for network connection are in general borne by the network customer, except for offshore wind farms, for which the connection costs are socialised. Operators of LNG terminals shall only bear 10 per cent of their connection costs according to a new ordinance (to be confirmed by the Federal Council).

Access to electricity networks is granted on the basis of standardised network access agreements concluded between the grid operator and the grid customer or, in the case of electricity suppliers, on the basis of supplier framework access agreements. The access agreement grants nationwide access to all electricity networks. The agreements are based on a model network access agreement developed by BNetzA.

Access to gas networks is based on capacity bookings in a two-contract entry-exit system: one contract is concluded between the grid customer and the grid operator for the feed-in of the gas, and a second contract is concluded between the grid customer and the grid operator for the off-take of the gas. Gas can be transported and traded without physical restrictions across networks, including on virtual trading points, within each of two gas market areas in Germany (GASPOOL and NetConnect Germany).

Network operators do not have exclusive rights to provide services within their network areas. Transmission and distribution networks are closely interlinked, and operators are obliged to cooperate. Contracts for network access and general terms and conditions are standardised and approved by BNetzA. BNetzA has the competence to set detailed rules on network access applicable to all network operators, for example in relation to balancing energy and capacity management. However, the European Commission holds the view that BNetzA does not enjoy enough discretion in the setting of network tariffs and other terms and conditions for access to networks and balancing services. It has therefore filed a complaint with the European Court of Justice (C-718/18).

Network operators may restrict network access to maintain system security. They must use non-discriminatory and market-based measures to prevent or eliminate bottlenecks. The increase in generation of electricity from renewable energy sources and the phase-out of nuclear energy is leading to a shift of generation to northern Germany, resulting in bottlenecks on the north-south transmission lines. Costs for re-dispatch measures of TSOs to relieve bottlenecks are socialised to all grid customers. Hence construction of additional electricity transmission lines is one of the key priorities of German energy policy. In addition, the installation of new onshore wind capacity in northern Germany has been limited to 902MW per year (to be revised in July 2019).

TSOs have to establish 10-year network development plans for electricity, gas and for connection of offshore wind farms every two years. The development plans set out the required grid expansion measures. BNetzA reviews the development plans and may request modifications. The necessity of all listed projects is then legally determined by the federal government. BNetzA is responsible for the actual planning approval for projects that cross the borders between German states.

### Rates

Since 2009, grid fees have been subject to revenue cap incentive regulation. Two years prior to the beginning of each five-year regulatory period, the competent regulatory authority determines a grid operator’s allowed cost and asset base by analysing its costs of the preceding financial year (photo year). The cost and asset base in the photo year is the basis for the network operator’s allowed revenues in the next regulatory period. The regulatory authority sets the grid operator’s individual annual revenue cap for each year of the five-year regulatory
period, taking into account individual and sector-specific efficiency targets and an allowed rate of return on equity set by BNetzA. During the regulatory period, the annual revenue cap will in principle only be adjusted in the case of an adjustment of the consumer retail price index or a change of the grid operator’s permanently non-controllable costs. As a result, the grid operator has an incentive to outperform its efficiency targets before the revenue cap is reset for the next regulatory period. Based on their fixed revenue caps, the grid operators charge the corresponding access fees to their grid customers.

The permitted rate of return on equity as set by BNetzA for the second regulatory period (gas: 2013–2017, electricity: 2014–2018) is 9.05 per cent before tax for new assets and 7.14 per cent before tax for old assets (commissioned before 2006). For the third regulatory period (gas: 2018–2022, electricity: 2019–2023), BNetzA has set the allowed rates of return on equity to 6.91 per cent before tax for new assets and to 5.12 per cent before tax for old assets. In March 2018, grid operators successfully challenged the new rates as too low before the Higher Regional Court of Düsseldorf. BNetzA appealed the decision before the Federal Court of Justice in April 2018. If the Federal Court upholds the decision of the Higher Regional Court, BNetzA will have to recalculate the allowed return on equity in favour of the grid operators.

In 2016, the Incentive Regulation Ordinance was amended mainly to improve investment conditions for DSOs. Capital costs for network investments made after the photo year are now recognised in DSOs’ revenue caps without delay. Very efficient DSOs may receive an efficiency bonus.

Grid customers with atypical grid use or with continuous and very high consumption (at least 7,000 hours and more than 10GWh per year) have a right to individual network fees below the regulated tariffs. Such individually agreed fees have to be notified to the competent regulatory authority.

iv Security and technology restrictions

There are no specific restrictions on technology transfer for the energy sector.

Based on a report from the TSOs, every two years BNetzA reviews whether the disruption or destruction of transmission assets in Germany could have a material impact on at least two EU Member States. BNetzA can declare such assets to be critical European infrastructure. TSOs have to develop specific security plans for such assets, including access control, security of IT systems and emergency protocols. In 2015, an IT Security Act was adopted that shall tighten IT security requirements and extend their scope to all assets required for secure network operation.

IV ENERGY MARKETS

i Development of energy markets

Gross energy consumption in 2018 decreased by 5 per cent compared to 2017; gross electricity consumption increased by 0.1 per cent. In 2018, primary energy consumption was composed of oil (34.3 per cent), natural gas (23.7 per cent), hard coal (10 per cent), lignite (11.3 per cent), nuclear energy (6.4 per cent) and renewable energy sources (14 per cent).

Gross electricity generation in 2018 was composed of lignite (22.5 per cent), hard coal (12.9 per cent), nuclear energy (11.8 per cent), natural gas (12.9 per cent), mineral oil (0.8 per cent), others (4.2 per cent) and renewable energy sources (34.9 per cent), the latter mainly consisting of wind power (17.3 per cent), hydropower (2.6 per cent), biomass
(7 per cent) photovoltaic (7.2 per cent) and waste (1 per cent). These figures illustrate that despite an increased share of renewable energy sources, conventional energy sources are still the backbone of the German energy supply.

With effect from 1 October 2018, the single German–Austrian price zone was split. Appeals against this decision, which results from a recommendation of the Agency for the Cooperation of Energy Regulators (ACER) are currently pending before the Court of the European Union. Austrian stakeholders argue that the German–Austrian interconnector itself is not congested and that congestion within Germany and loop flows to neighbouring countries should be mitigated otherwise.

Germany has two separate dual-quality (high caloric and low caloric gas) gas market areas: NCG and GASPOOL. Within these gas market areas, gas can be traded without capacity restrictions at virtual trading hubs through matching buy and sell orders between two balancing groups. Owing to the decreasing production of low caloric gas in Germany and the Netherlands, until 2030 all grids and customer units will consecutively be transferred to comply with high caloric standards.

The European Energy Exchange AG (EEX) in Leipzig operates organised markets for trading in electricity, natural gas, oil, coal, carbon dioxide emission allowances and guarantees of origin. EEX offers trading of electricity futures for delivery in the market area Germany–Austria and trading of gas futures and short-term gas contracts for delivery in the two German market areas GASPOOL and NCG. The electricity spot market for Germany–Austria is operated by EPEX SPOT SE in Paris.

Prices on the spot and futures markets are based on bids by generators and customers. The order of the bids is determined by the short-run marginal costs of the power plants (merit order). Owing to the statutory priority of feed-in of renewable energies (‘produce and forget’), electricity from renewable sources is always first in line in the merit order, usually followed by nuclear energy and coal-fired power plants. The prices on the spot and forward markets are the benchmark for wholesale prices and over-the-counter trades.

The spot and futures markets are energy-only markets (i.e., there are no capacity payments). The increase in generation from renewable energies has led to a decrease of wholesale prices and has pushed conventional generation capacity out of the merit order, in particular flexible gas-fired power plants.

In order to guarantee security of supply, the Electricity Market Act of 2016 implemented several capacity mechanisms without, however, introducing a real capacity market. The ‘network reserve’ is composed of ‘system relevant’ power plants, mainly in Southern Germany, that would otherwise be decommissioned, providing additional re-dispatch potential if necessary. The ‘capacity reserve’ shall be provided by power plants outside the energy market being remunerated for the provision of capacity via a tendering process. Until 2023, the function of the capacity reserve will mainly be served by lignite-fired power plants that are being transferred to ‘security standby mode’ before being decommissioned four years later.

**ii Energy market rules and regulation**

The energy market operated by EEX is subject to the Exchange Act. Under the authority of the State Ministry of Economy, Labour and Transport in the German state of Saxony, an independent market surveillance body continuously supervises trading activities in order to prevent market manipulation.

Under the EU Regulation on wholesale energy market integrity and transparency (REMIT), market participants are required to publish inside information in an effective and
REMIT also prohibits market abuse in wholesale energy markets in the form of market manipulation and insider trading. Since 2015, market participants have to register with BNetzA and report details of wholesale energy transactions executed at organised market places to ACER.

Since 2014, all EU-based entities that enter into derivatives transactions are required to report details of these transactions to a trade repository under the European Marketing Infrastructure Regulation (EMIR). There is also an obligation to report certain existing and historical derivatives transactions, although deadlines for this vary. Furthermore, EMIR established a central clearing obligation for certain over-the-counter derivatives and the application of risk mitigation techniques for non-centrally cleared over-the-counter derivatives.

iii Contracts for sale of energy

In principle, there are no regulatory limitations as to the entering of individual contracts for the sale of energy, both at wholesale and retail level. However, household customers have a right to be supplied at standard (but not regulated) tariffs by the local supplier with the most household customers within a network area (supplier of last resort). Energy supply contracts with household customers also have to comply with certain transparency and information requirements.

While there is no *ex ante* price regulation of wholesale or retail energy prices, regulated network charges, taxes and surcharges (such as the surcharge for renewable energies) meanwhile account for more than half of the final energy prices. Competition authorities may review energy prices (except the regulated components) and prohibit dominant suppliers from charging prices that unreasonably exceed costs or that are lower than on comparable markets.

In recent years, price increases for final customers based on the passing-on of input costs (e.g., increase in fuel cost for electricity generation) have frequently been annulled by the courts, arguing that these were not justified or that provisions in energy supply contracts enabling such price increases were not sufficiently transparent. Following landmark decisions of the European Court of Justice and the German Federal Court (BGH) in 2013 and 2014, according to which a standard clause for price adjustments that was widely used in supply agreements is invalid, utility companies have to provide information on the scope, reasons and preconditions for the adjustment.

iv Market developments

The large German utilities are increasingly adapting their business to the changing market environment by divesting or consolidating their conventional power generation facilities and investing in renewable energy sources, grids and new forms of energy supply and customer solutions. In 2016, RWE transferred its renewables, grids and supply business to its subsidiary, Innogy, while E.ON spun off its conventional generation and trading business into a new listed company (Uniper). In January 2018, E.ON sold its shares in Uniper to the Finnish energy supplier Fortum and in March 2018 E.ON announced that it would acquire RWE’s majority stake in innogy and in return E.ON would transfer to RWE most of E.ON’s renewables business. Thus, in the future, RWE would focus on conventional and renewable generation while E.ON would concentrate on energy networks and customer solutions.
Germany

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Reform of the EEG and Offshore Wind Farms Law

In 2017, a major reform of the EEG, the law governing the development of renewable energy sources, entered into force. It aims to move away from ‘produce-and-forget’ guaranteed feed-in tariffs towards market-based mechanisms for their remuneration. Therefore, the EEG 2017 introduced auctions as the basic mechanism to determine the remuneration for electricity from onshore and offshore wind power, photovoltaic power and biomass, subject to a number of exemptions; for example, for smaller facilities, for which remuneration remains fixed by law. Auctions for other renewable energy sources, for example, geothermal energy, may be introduced at a later stage. The technology-specific auction volumes are limited to:

- 2,675MW in 2019, 2,700MW in 2020, 2,650MW in 2021 and 2,900MW per year as of 2022 for onshore wind;
- 475MW in 2019, 400MW in 2020, 350MW in 2021 and 600MW per year as of 2022 for solar;
- 150MW in 2019 and 200MW per year as of 2020 for biomass; and
- 15GW until 2030 for offshore wind.

Since December 2017 the BNetzA also conducts two auctions for electricity from co-generation per year. In addition, BNetzA carries out technology neutral auctions for onshore wind and solar power together in the amount of 400MW/year from 2018 to 2020.

In addition to the EEG 2017, the Offshore Wind Farm Act sets out rules for the planning, tendering and approval of offshore wind farms (OWFs). It applies to OWFs in the German exclusive economic zone that commissioned as from 1 January 2021. The main aim of the law is to better harmonise the construction of OWFs and their grid connections to the onshore grid. As a main feature, the Federal Maritime and Hydrographic Agency instead of the developers in a central planning model identifies suitable areas for the construction of OWFs.

State-aid proceedings and support for energy-intensive industries

Since 2012 the compatibility of the EEG support scheme with EU state-aid law has been under dispute between the European Commission and the German government.

In November 2014, the European Commission after an in-depth investigation considered that the EEG 2012 constituted state aid, but was, in principle, in line with the Commission’s Guidelines on Environmental and Energy State Aid. However, the Commission regarded the reduction of the EEG surcharge for certain companies in energy-intensive industries to constitute state aid incompatible with the internal market and ordered Germany to recover such aid immediately. In March 2019 the European Court of Justice overruled this decision of the European Commission stating that even the support mechanism of the EEG 2021 did not constitute state aid.

As regards the EEG 2014 and the EEG 2017, the Commission has already confirmed their compatibility with EU state-aid law.

ii Energy efficiency and conservation

Germany is about to miss its goal to reduce emissions by 40 per cent in 2020 compared to 1990. Germany is also about to miss its goal to reduce gross energy consumption by 20 per
cent in 2020 compared to 2008. In 2018, the decline was only 8 per cent as compared to 2008. In reaction to that, the new German government intends to formulate a cross-sector energy efficiency strategy based on the ‘efficiency first’ principle. Based on the results of BMWi’s green paper on energy efficiency, the National Action Plan Energy Efficiency shall be further developed and implemented. Concerning conservation, the German government implemented a Commission for Growth, Structural Transformation and Employment, which should develop a plan for the phase-out of lignite- and coal-fired power plants. The Commission published its final report in January 2019 in which it proposes a gradual phase-out until 2038. Furthermore, the German government intends to introduce a Federal Climate Protection Act of which the Federal Ministry for Environment, Conservation and Nuclear Safety published a first draft in early 2019. However, the draft has not been adopted by the government so far and discussions within the coalition are still ongoing.

iii Technological developments

Driven by the need to store the surplus electricity from renewable energy sources, the installation of power storage facilities, both at household and at commercial level, is developing very dynamically. Storage facilities are based on a large variety of technologies, such as battery storage, power-to-gas, power-to-heat or power-to-liquid.

Also, e-mobility picks up speed; however, from a low level. In 2018, new registrations of electronic vehicles increased by 43.9 per cent compared to 2017. In January 2019, 83,200 electric vehicles were registered in Germany. The government wants to promote this development by providing public funding beyond 2020. Various market players have announced that they will invest in the charging infrastructure and the government aims to have an additional 100,000 charging points installed by 2020.

Another trend is blockchain, a technology based on continuously growing lists of digital records (blocks) that are linked and secured using cryptography. Recently, several platforms have been launched where market players may trade peer-to-peer using blockchain technology.

In relation to smart meters, the EU has set a non-binding target of rollout to 80 per cent of all consumers by 2020. In 2016, the Act on the Operation of Measuring Points (Msbg) entered into force, which provides for the introduction of smart meters, including rules on data protection, data access, rollout and financing of the rollout. The rollout is expected to start in 2019. The Msbg establishes maximum price limits for the installation and service of the smart meters depending on the individual consumption. Provided the maximum price limits and the outstanding certification requirements are met, the installation of smart meters will be mandatory for consumers with a consumption above 10,000kWh per year (as of 2020, more than 6,000kWh/year). The installation of smart meters for consumers with an annual consumption below 6,000kWh/year is optional. The goal is to complete the smart meter rollout in 2032.

VI THE YEAR IN REVIEW

The fundamental reform of the EEG, introducing auctions as the basic mechanism to determine the remuneration level for the support of power from renewable sources, has proved successful in countering a further cost increase. The increased share of intermittent
renewable generation, however, puts further pressure on the viability of conventional generation facilities. This induced the large German utilities to accelerate the restructuring and consolidation of their generation portfolios and business models.

At the same time, the German energy market saw an increased entry of new market players. These are both start-ups promoting new technologies such as blockchain or e-mobility and companies from other sectors, such as IT and telecoms, driving forward the digitalisation of the energy sector.

VII CONCLUSIONS AND OUTLOOK
The German government in February 2018 intensified its efforts to reform the German energy market without endangering Germany's international competitiveness and security of supply. However, in order to ensure that Germany reaches its 2030 climate goals the government will have to further specify the necessary policy measures, including in particular a plan on how to progressively reduce the generation of electricity from coal to ultimately zero as well as a coherent strategy for the integration of renewable energies into the heating and transport sector.

In 2019, the German government needs to start transposing the requirements of the eight legislative acts of the European Clean Energy Package (CEP), which inter alia contain recasts of the rules on renewables energies and the electricity market design. As the CEP leaves substantial room for discretion of the Member States, the transposition needs to be determined in a political process. Additionally, the decision of the European Court of Justice stating that the EEG 2012 did not constitute state aid allows for more discretion of the German government to shape or reform its support schemes.
I OVERVIEW

The Indian economy is undergoing large-scale transformation across various key sectors, and energy security has emerged as one of the key focus areas in unlocking the country’s potential for meaningful development. Along with key policy changes, the government is working towards improving the bankability of key energy assets by restructuring and improving the financial health as well as the operational efficiency of distribution companies, along with continuing its efforts to promote new areas of growth such as India’s offshore wind energy sector and the solar rooftop segment. The primary concerns for the country continue to be providing reliable, uninterrupted electricity to all and finding solutions to the unutilised capacity. While the majority of the contribution to India’s energy mix continues to come from conventional energy sources, the government remains keen on scaling up the Indian renewable energy market and has set a target of 175GW of renewable energy capacity to be installed by 2022. India ratified the Paris Convention on Climate Change and aims to produce at least 40 per cent of its installed electricity capacity by 2030 from non-fossil fuels. Encouraged by the success of its initiatives in the renewable energy sector, and to ensure that commitments made to the international community are fulfilled, the government has considerably increased its renewable energy production targets, especially for the onshore wind energy and solar energy production.

II REGULATION

i The regulators

The power sector is governed by the federal government through, primarily, the Ministry of Power and the Ministry of New and Renewable Energy (the Renewable Energy Ministry). Currently, the Ministry of Power and the Renewable Energy Ministry are under the charge of a single minister to ensure an identity of objectives and synchronisation in objectives and policies. The Electricity Act 2003 (the Electricity Act) is the primary statute that governs generation, transmission, distribution and trading of electricity. The Electricity Act provides for the formulation of the National Electricity Policy 2005, the National Tariff Policy 2016 (the Tariff Policy), the National Electricity Plan, establishment of independent electricity regulatory commissions at the central level (the Central Electricity Regulatory Commission (CERC)) and state level (the state electricity regulatory commissions (SERCs)) and the setting up of the Appellate Tribunal for Electricity. The relevant SERCs exercise jurisdiction

1 Neeraj Menon is a partner and Karthy Nair is a senior associate at Trilegal.
over intrastate electricity regulatory matters (including tariffs), whereas the CERC exercises jurisdiction over all interstate electricity regulatory issues (also including tariffs). The revised Tariff Policy was announced in 2016, with some of the key highlights being an increase in the solar renewable purchase obligation (RPO) to 8 per cent by 2022 (a subsequent order issued by the Ministry of Power on 14 June 2018 has increased this to 10.5 per cent), exemption on the payment of interstate transmission charges for wind and solar power projects, applicability of RPOs on co-generation power plants, compulsory procurement by distribution companies of 100 per cent power from waste to energy plants in the respective state and development of intrastate transmission projects through a competitive bidding route for projects above a particular project cost threshold, to be decided by the SERCs. The government also proposed significant amendments to the Electricity Act, particularly in terms of enabling consumers to choose their electricity supplier by segregating the entities that distribute and supply power, imposing stricter penalties for non-compliance with the RPOs and introducing a renewable generation obligation on thermal power producers, requiring them to set up or contribute towards renewable generation capacity. While the proposed amendments have not yet been finalised, the central government is exploring other initiatives with the state governments on measures to make the power sector more competitive.

The Department of Atomic Energy and the Atomic Energy Regulatory Board regulate nuclear energy in India. The government is also in the process of setting up a statutory, independent and autonomous Nuclear Safety Regulatory Authority to replace the Atomic Energy Regulatory Board.

In the past few years, the Ministry of Coal and the state-controlled Coal India Limited (CIL) have been at the receiving end of nationwide criticism for failure to supply the requisite quantity and grade of coal, leading to strong lobbying on the part of power producers for assured coal supplies by the government. In September 2014, the Supreme Court cancelled 204 out of 218 coal blocks allocated to various entities between 1993 and 2010 by holding the procedure of allocation to be illegal and arbitrary. However, with the enactment of the Coal Mines (Special Provisions) Ordinance 2014, and subsequently, the Coal Mines (Special Provisions) Act, 2015 (Coal Mines Act), there has been a push towards ensuring continuity in mining operations and transparency in allocation of coal blocks. In accordance with the Coal Mines Act, which now governs the coal block allocation process, the government has re-started auctioning the cancelled coal blocks and out of the re-auctioned blocks, certain blocks are now operational as well. Further, with the Coal Mines Act having lifted end-use restrictions on the coal mined from some of the re-allocated blocks to enable the sale of coal in the open market, the government has recently approved the methodology for auction of coal mines for the commercial mining of coal without any restrictions on sale or utilisation of coal. This methodology envisages that the auction will be an ascending forward auction with the bid parameter being the price (in rupees per tonne) paid to the government on the actual production of coal from the mine. The government’s release in this regard also sets out that this is the most ambitious coal sector reform since 1993 and is expected to better the energy security scenario in India.

In 2016, the Union Cabinet had approved a proposal for flexibility in utilisation of domestic coal with an aim to reduce the cost of power generation. The Central Electricity Authority has now devised a methodology for implementing the use of coal assigned to particular states in the power generating plants in such states, which will improve the

2 The Department of Atomic Energy is directly under the Prime Minister’s charge.
efficiency of coal-based thermal power plants by reducing cost of coal transportation and allow coal swapping among plants. The government has also put in place the Scheme for Harnessing and Allocating Koyala (coal) transparently in India (the SHAKTI policy), where the government coal companies will grant coal linkages on notified prices on an auction basis for coal-based power projects that have power purchase agreements (PPAs) in place. The bid parameter for this auction will be the levelised discount on the existing tariff that the independent power producer is willing to provide. The first bid under the scheme was completed in 2017 and saw nearly 27.18 million tonnes per annum of coal being booked by power developers. This scheme has received a favourable response from generating companies and is expected to result in an annual generation of over 47 billion units of electricity.

The Ministry of Petroleum and Natural Gas (MoPNG) deals with issues relating to petroleum, natural gas, coal bed methane, shale gas and other petroleum products. Along with exploration and production, the MoPNG also monitors its supply, distribution, marketing and pricing. The Directorate General of Hydrocarbons (DGH), which is under the administrative control of the MoPNG, regulates the upstream segments for issues relating to exploration and production of oil and gas. The Petroleum and Natural Gas Regulatory Board (PNGRB) is the midstream and downstream regulator that regulates the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas.

ii Regulated activities

Electricity generation, including captive generation, is a delicensed activity. While generation activities can be freely undertaken without a licence, approvals and procedures under other laws for land acquisition, environmental, corporate safety of electrical equipment and labour compliance must be adhered to.

Electricity distribution activities (except for distribution of electricity in rural areas) require a licence from the relevant SERC. Electricity trading is a distinct recognised activity for which a separate licence is required from the CERC or a SERC (for interstate and intrastate trading respectively). Licences are awarded by the CERC for interstate transmission activity by way of a competitive bidding procedure in accordance with CERC regulations. For intrastate transmission services, licences are awarded by the relevant SERC. The proposed amendments to the Electricity Act provide for disaggregation of distribution activities by requiring the supplier of electricity and distribution network provider to be separate entities so as to enable consumers to choose their supplier. If these amendments come into force, supply of electricity will also require a licence from the relevant SERC, and the supply and distribution of electricity will be governed by separate operative codes to be issued by the relevant SERC.

Exploration of oil and gas are separately licensed activities. The DGH awarded licences through international competitive bidding for natural gas exploration blocks under the New Exploration Licensing Policy (NELP) rolled out in 1999. The production-sharing contract (PSC) under the NELP programme stipulated conditions regarding pricing and sharing of total product obtained with the government. The DGH has successfully carried out nine rounds of bidding under NELP, in which 254 oil and gas blocks have been awarded.

The MoPNG notified the New Domestic Natural Gas Pricing Guidelines 2014, which provide for the prices to be fixed on the basis of the annual average of the price of gas at specified international hubs, and require notification of the prices determined by the government on a biannual basis.
The Coal Bed Methane (CBM) Policy 1997 offered blocks for exploitation of CBM through biddable revenue-sharing based on production-linked payment. The Policy specified modalities regarding the commercial development of CBM, identification and allotment of blocks and fiscal incentives or provisions. The government has also approved the marketing and sale of CBM by contractors on arm’s length prices in the domestic market. Recognising the constraints experienced in the present PSC format and differences in the fiscal and contractual regime for oil and gas and CBM, the government has framed the Hydrocarbon Exploration Licensing Policy (HELP), which provides for a uniform licensing system to cover all hydrocarbons, such as oil, gas and CBM, under a single licensing framework, allowing the possibility of exploring overlapping resources in a single block. Under HELP, both foreign and domestic companies can have a 100 per cent participating interest without the involvement of a government company in a joint venture. Among the ostensible reasons for concluding the NELP is the fact that blocks that were bid for under numerous PSCs are mired in disputes over the inflating costs of production and deteriorating production of oil and gas. Through HELP, a revenue-sharing arrangement has been implemented, where bidders will be selected based on their upfront revenue-sharing commitment offered to the government, which will be payable from the first batch of production. The revenue-sharing model will not be subject to cost recovery and therefore aims at eliminating the often tedious process of cost scrutiny that the government was required to undertake under the previous regime. Although the move to a revenue-sharing model has largely been well received, a few industry participants are likely to get discouraged under the new model as the investment recovery periods for companies will increase. The HELP has also introduced an open acreage policy in India (OALP), which permits the licensee to exploit the full range of hydrocarbons accessible in a single block and allows companies to approach the government at any time, expressing their interest in bidding for one or more blocks, after which the government would invite competitive bids from others interested in the same blocks. Contracts have been signed for nearly 55 blocks under OALP Bid Round I and the government has launched OALP Bid Round II for 14 blocks and OALP Bid Round III for 23 blocks. The government has also introduced policy guidelines for exploration and exploitation of shale gas and oil by national oil companies, pursuant to which, the oil companies have started the first phase of assessment and have initiated exploration activities in over 70 areas. While the potential shale gas reserves overshadow those of conventional gas, India has a long way to go in identifying shale gas-rich basins and acquiring the necessary technology and experience to extract shale gas, specifically in the absence of private participants.

Petroleum, natural gas and city gas distribution (CGD) networks can be developed either through an expression of interest to the PNGRB or under competitive bids invited by the PNGRB. Under the expression-of-interest route, the PNGRB must publicise upon receipt of such an expression of interest, to receive proposals or comments from different entities, and may invite competitive bids or allow for the proposal (with or without modification).

iii Ownership and market access restrictions

Over the past decade, the government has progressively liberalised the energy sector, although government companies continue to be active players. Up to 100 per cent foreign direct investment (FDI) is permissible in generation (except nuclear power), transmission,
distribution of electricity and power trading, as well as in the oil and gas sector and up to 49 per cent in power exchanges without prior regulatory approval. Such investments are subject to sector-specific laws and policies. The revised Consolidated FDI Policy, while maintaining the 49 per cent cap on FDI in power exchanges, has done away with the restriction that FII/FPI could only invest in power exchanges through the secondary market.

A majority of generation, transmission and distribution capacities are with either public sector companies or with state electricity boards (SEBs); however, private sector participation is increasing, especially in generation and distribution. The interstate transmission system is mainly owned and operated by Power Grid Corporation of India Limited, a state-owned company, and the intrastate transmission system is owned and maintained by state utilities. However, the public–private partnership (PPP) structure is increasingly preferred by the government for setting up interstate and intrastate transmission networks. Electricity distribution is largely in the control of government distribution companies, with privatisation being slow largely on account of the huge legacy liabilities of the state distribution companies. However, a few examples of privatisation in certain areas (such as Delhi, Orissa, Ahmedabad and Mumbai) have met with success. Apart from private participation in the distribution sector, distribution licensees in several states (particularly Maharashtra, Rajasthan and Odisha) have engaged distribution franchisees to discharge their universal supply obligations. Given that a distribution franchisee does not require a licence to function (unlike a distribution company), there has been considerable private interest in the sector with several companies submitting bids in recent auctions. The role of a distribution franchisee typically includes supply of electricity on behalf of the distribution company with related functions such as meter reading, tariff collection and operation and maintenance of distribution assets. That said, there have been multiple bid processes for selection of franchisees that have faced delays on account of reports of considerable aggregate technical and commercial losses that have to be borne by private franchisees.

In India, the ownership of all mineral resources, including oil and gas, vests with the government, and is administered through the MoPNG. The Gas Authority of India Limited and the Oil and Natural Gas Company are the largest owners of oil and gas pipelines in the country. Private players are increasingly entering the CGD space in urban areas.

iv Transfers of control and assignments

While there are no specific restrictions on transfer of control or assignment of a generating company, PPAs issued pursuant to certain renewable energy policies and bidding documents for thermal and renewable power procurement provide for shareholding restrictions for a certain period post-commercial operation. For instance, the Ministry of Power’s revised standard bidding documents for long-term (seven to 25 years) procurement of power from thermal power projects (Revised SBDs), provide for a lock-in period (though on a sliding scale) of up to 10 years following commercial operations.

Holders of licences for oil and gas exploration can transfer or assign all or part of their participating interest under the PSC, including any change in control of a party, with prior consent of the government.

3 Investments of up to 49 per cent are permitted in petroleum refining undertaken by public sector entities.
Other than these sector specific restrictions, provisions of the Companies Act 2013, Competition Act 2002, and the Securities and Exchange Board of India (Substantial Acquisition of Shares and Takeovers) Regulations 2011 (applicable to listed companies) will apply with respect to change in shareholding through mergers and acquisitions.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Under the Electricity Act, SEBs were required to be unbundled into separate generation, distribution and transmission companies and most states have now completed the process. Transportation, distribution and marketing activities in the oil and gas sector are yet to be unbundled. The PNGRB regulations provide for legal separation of entities engaged in marketing of natural gas and laying, building, operating or expanding pipelines for transportation of gas on common carrier or contract carrier basis on or before 31 March 2017. However, these regulations have been stayed by the Delhi High Court and the matter is currently sub judice.

ii Transmission/transportation and distribution access

In the electricity sector, transmission licensees must provide non-discriminatory open access to its transmission system for use by other persons (including electricity distributors, traders and generating companies). Open access to distribution networks is also granted to bulk power consumers (i.e., consumers of above 1MW), to procure electricity at unregulated prices from entities other than the area distribution licensee. Separately, the government has the ability to issue directions to generators on operation of their power stations in extraordinary circumstances, a tool that more often than not has been used by state governments to restrict supply of power outside the state (in the event of a shortage).

The PNGRB prescribes an access code for common or contract carrier natural gas pipelines, regulations for capacity release for natural gas pipelines and requires natural gas transporters to declare capacity available for common carriage on a monthly basis.

iii Terminalling, processing and treatment

The PNGRB regulates the storage and treatment of oil and gas, including prescribing the eligibility conditions for registration of liquefied natural gas (LNG) terminals and prescribing the technical and safety standards for pipelines and CGD networks.

For imported LNG, the price under the term contracts and spot cargoes are mutually determined and are usually very high. Consequently, the MoPNG is currently exploring options such as price pooling to average out the prices and now that new pricing guidelines have been introduced, it is to be seen whether a separate price pooling mechanism will be adopted by the government.

iv Rates

Under the Electricity Act, transmission schemes are implemented either through the tariff-based competitive bidding process or under a cost-plus mechanism where a regulated tariff is determined by the relevant electricity commission. The CERC adopts a ‘point-of-connection’ method for calculating interstate transmission charges and losses, which aims to develop a uniform transmission charge-sharing mechanism among grid constituents.
However, to help meet the proposed target of 175GW of renewable energy capacity by 2022, the government has, among other measures, exempted the payment of interstate transmission charges for wind and solar power projects under the new Tariff Policy. Recently, the CERC issued an order clarifying that in order to avail the exemption, the (i) project must be commissioned before 31 March 2022; (ii) the project must be executed pursuant to a competitive bidding process conducted by the government; and (iii) valid PPAs must be executed for sale of such generation capacity to all entities. The tariff for electricity distribution, comprising wheeling charges and cost of supply, is levelled and determined on a cost-plus basis by the relevant SERC. However, as renewable energy tariffs inch towards achieving grid parity, the government is slowly scaling back benefits allowed to renewable energy developers. For instance, the Ministry of Power has limited the exemption from payment of interstate transmission charges and losses to projects that are commissioned before 31 March 2022 and that are supplying power to all entities including distribution licensees for compliance of their renewable purchase obligation. The government has also decided against extending the exemption on corporate tax on power producers (including renewable energy developers), which expired in 2017. The PNGRB has enacted regulations for determination of transportation tariff for petroleum and petroleum products, natural gas pipelines and CGD network. The tariff for such pipelines is determined taking into consideration a reasonable rate of return on the normative level of capital employed plus a normative level of operating expenses in the relevant pipeline.

V Security and technology restrictions
With a sophisticated energy infrastructure and now smart grids being proposed, cybersecurity concerns are paramount. The Information Technology Act 2000 addresses hacking and security breaches of information technology infrastructure. The government issued a National Cyber Security Policy in 2013, which aims at creating a secure cyber ecosystem, encourages use of open standards to facilitate interoperability and data exchange, and provides for creating mechanisms for security-threat early warnings and vulnerability management.

Technology transfers into India are permitted in all sectors, including energy. All payments made for technology transfers into India are subject to Indian exchange control regulations. Export of technology transfers for specific sectors requires a licence under India’s Foreign Trade Policy.

IV ENERGY MARKETS
The National Electricity Policy 2005 envisions 85 per cent of power from new capacities being contracted through long-term PPAs and the remaining 15 per cent power capacity through market mechanisms. It is also expected that more merchant capacity will be available in the next few years as the Revised SBDs provide for a quantum of installed capacity to be sold at market-determined prices. The NITI Aayog (the Indian government’s think tank and planning wing) released a draft of the National Energy Policy for public comments in July 2017. This policy sets out four objectives that the government hopes to achieve in the energy sector: access at affordable prices, improved security and independence, greater sustainability and economic growth. To achieve these objectives, this policy contains several recommendations such as better coordination between government ministries, reducing dependency on imported coal, increased use of renewable energy and enhanced investment in rural electrification. Recently, the Cabinet Committee on Economic Affairs
India

has also provided an in-principle approval to the sale of the government’s stake in the Rural Electrification Corporation to Power Finance Corporation (which is a government backed financial institution).

The power market is dominated by long-term contracted power. For thermal power projects (coal and gas) and hydro projects, long-term power is procured through a negotiated route or pursuant to a competitive bidding route. The Ministry of Power has directed state governments and distribution companies to procure power under the competitive bidding route (except that mandatory competitive bidding for hydropower projects has now been postponed till the end of 2022). Bidding for long-term procurement from thermal power stations can be done on the basis of the Revised SBDs that provide for two modes of bidding and supply of electricity. Under the DBFOO model, a distribution licensee invites bids to procure a specified quantum of power, while also prescribing the type of fuel and technology that is to be used for the supply. Under the DBFOT model, a distribution licensee invites bids for setting up a project on the basis of the lowest tariff, while also specifying the fuel and location of the project (which is required to be arranged by the distribution licensees).

To specifically address stakeholder concerns on determination and impact of rising fuel import costs, the Revised SBDs provide for the cost of imported fuel to be benchmarked at actuals and linked to prevailing prices on international indices. In 2015, the government further amended the guidelines for procurement of power through the DBFOO route to revise the tenure to seven to 25 years and allowing the distribution licensees to deviate from the revised SBDs with the prior approval of the CERC or SERCs, allowing more flexibility for procurement of power. In 2019, the government issued new guidelines and bidding documents in order to facilitate use of coal as per the SHAKTI Policy and to introduce the e-bidding process of procurement.

While several states have commenced (and some have even concluded) the bidding process under the DBFOO model, the DBFOT model has met with severe criticism from market players, who have voiced concerns on the inequitable apportionment of risks. This has resulted in the Ministry of Power constituting a committee to review the DBFOT standard bidding documents, pursuant to which the further revised bidding documents for the DBFOT model are expected to be released by the ministry later this year.

While long-term procurement remains a top priority, the government is also determined to set up the short-term and medium-term markets for procurement of electricity. In January 2017, the government issued revised guidelines for procurement of electricity on medium term (one to five years) from power stations set up on a finance, own and operate basis. The revised guidelines mandate tariff determination through an open and transparent e-auction, with an overall aim of reducing power procurement costs. Similarly, guidelines for short-term (i.e., for a period of more than one day to one year) procurement of power by distribution licensees through a tariff-based bidding process have also been amended in 2016 to introduce the concept of reverse auction on an e-platform in the short-term supply of power. In April 2018, the Ministry of Power issued a pilot scheme to facilitate the purchase of power (aggregated power of 2,500MW for three years) from coal-based power plants that are commissioned but do not have a PPA in place. This scheme envisages that an aggregator will enter into PPAs with the generating companies along with back-to-back arrangements between the aggregator and distribution companies.

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4 The DBFOO model refers to a project set up on a design-build-finance-own-operate basis.
5 The DBFOT model refers to a project set up on a design-build-finance-own-transfer basis.
In 2015, the Ministry of Power issued a notification introducing a targeted gas supply scheme focused on gas-based thermal power plants with stranded capacity. The scheme envisaged facilitating the import of requisite quantities of gas with considerable incentives in the form of tax exemptions on the import and regasification of LNG as well as discounted gas transportation rates for financial year 2015–2016 and financial year 2016–2017. A target of 30 per cent plant load factor was set for the operational and stranded power plants, which was to be achieved towards the end of 2015–2016. Although the plant load factor remains around 30 per cent, the scheme has not been extended beyond financial year 2016–2017.

On the distribution front, the major problems plaguing the power sector in India are the abysmal credit ratings of the state distribution companies and their persistent failure to honour payments to generators under PPAs or extensive delays in doing so. Distribution companies have borrowed heavily to finance losses in their businesses, and are facing major hurdles in repaying their debt. The government launched the Ujwal Discom Assurance Yojana (the UDAY scheme) in November 2015, with the objective of improving the operational and financial efficiency of state-owned distribution companies. One of the major features of the UDAY scheme involves requiring participating states to take over 75 per cent of the debt of distribution licensees by way of a grant over a period of two years and issue non-statutory liquidity ratio bonds, including state development loan bonds for subscription by pension funds, insurance companies and other institutional investors. Under the UDAY scheme, lenders and financial institutions will not levy prepayment charges on a distribution licensee’s debt, and will waive off unpaid overdue interest, including penal interest. For financing future losses and working capital of distribution companies, state governments will take over and fund future losses in a graded manner until financial year 2020-2021. The state governments have come forward in their support of the scheme and, at the time of writing, 32 states and union territories have signed up for the UDAY scheme, with almost all major distribution companies covered by UDAY. The state distribution companies participating in the scheme have reported significant interest cost savings and a sharp reduction in revenue losses. While the UDAY scheme initially reduced the woes of distribution companies in poor financial health, it has done little to bring about a significant or lasting impact on the power sector. The Parliamentary Standing Committee on Energy has estimated that investments of about 1,750 billion rupees (in private power generation) are currently at the risk of being declared ‘non-performing assets’ by the Reserve Bank of India. One predominant reason for the decline in the financial performance of these assets has been the significant delay in payments by the distribution companies. On a related note, with the inception of the Insolvency and Bankruptcy Code 2016, several captive power assets (attached to steel manufacturing units for which insolvency proceedings have been initiated) and power generation companies have been brought to the National Company Law Tribunal (NCLT) for commencement of insolvency proceedings. There have also been reports of a generation company taking a state-run distribution company to the NCLT for failure to pay dues over a period of three years. Insolvency resolution experts in India are also apprehensive about finding suitable buyers for these stressed assets given significant project completion costs and low bankability in terms of timely payments from distribution companies.

For renewable energy projects, contracts are entered into with state utilities under specific state policies at preferential tariff or through competitive bidding depending on the state or central policy. Other modes of power sale include captive consumption and sale to
consumers through open access. The CERC, through its Power Market Regulations 2010, seeks to promote and regulate interstate electricity transactions in various contracts (such as ancillary services market contracts and trading in renewable energy certificates (RECs)).

In January 2019, the Ministry of Power, in consultation with the Ministry of External Affairs, issued new guidelines for cross-border trade of electricity with neighbouring countries like Bhutan, Nepal and Bangladesh to facilitate the cross-border trade with greater transparency, consistency and predictability. The tariff for the cross-border transaction is proposed to be determined through government-to-government negotiations, and then adopted by the relevant electricity regulatory commission for electricity exported and imported, but may also be determined by competitive bidding for electricity imported by Indian entities. The guidelines also aim at evolving a dynamic and robust infrastructure along with reliable grid operation for cross-border transactions of electricity.

The REC is a market-based policy instrument introduced to increase and promote renewable energy capacity. Renewable energy producers who opt for the REC route are issued tradeable generation-based certificates that represent the renewable energy component of electricity generated, in addition to the average pooled cost of electricity from non-renewable sources of electricity of the past year. Generators who opt for the REC route cannot opt for the preferential feed-in tariff offered by the state distribution companies. These RECs can be bought by certain obligated entities (such as electricity distribution licensees and captive power consumers) to fulfil their RPOs.

In 2016, the government introduced HELP to revive the ailing gas market by providing for pricing freedom for gas discoveries in blocks that were yet to commence commercial production. HELP also removed restrictions on the companies on exploration by allowing them access to the national data repository maintained by the government that has the data and gives them the discretion to explore the areas for gas as per their choice. In addition to HELP, the New Domestic Gas Pricing Guidelines were introduced with the underlying principle that producers in India should get a price similar to the rates prevalent in the international markets, which, in turn, is expected to increase investment in the sector and reduce the dependency on imports. However, the government recently issued a notification stating that the domestic gas pricing regulations will not be applicable on coal bed methane, and granted the coal bed methane producers marketing and pricing freedom to sell CBM at arm's-length price in the domestic market.

In relation to the allocation of coal blocks, the government had notified the Coal Block Auction Rules 2017 (2017 Allocation Rules) under the Mines and Minerals (Development and Regulation) Act 1957 on 13 July 2017, which set out the key aspects such as the cap on the number and quantity of coal that may be allotted to a private entity, the reverse auction-based tender process and relaxations for coal procured for ultra mega power projects (set up under the scheme of Ministry of Power in this regard). All allocations made under the erstwhile Auction by Competitive Bidding of Coal Mine Rules 2012 have now been migrated to the 2017 Allocation Rules.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The regulatory environment increasingly seeks to incentivise renewable energy, with favourable tariff regimes established by SERCs. The Electricity Act, the National Electricity Policy and the Tariff Policy encourage private sector participation in renewable energy through measures
such as providing for feed-in tariffs, fixing minimum RPOs for distribution companies and captive power users and providing incentives such as accelerated depreciation schemes, excise duty exemptions and reduced customs duty on renewable energy equipment. In addition, a renewable energy project developer is also entitled to receive RECs if it does not opt for preferential feed-in tariffs. Several states have put in place specific policies to promote renewable energy development; however, incentives and policies are not always consistent between states and developers often shop around based on the policy that best suits their financial model and operational expertise. Consequently, the development of renewable energy in India is geographically skewed.

**Onshore and offshore wind power**

The past few years have witnessed a transition in the onshore wind power sector in India. The policy framework for subsidy driven wind power procurement regimes (feed-in-tariff, generation-based incentive and accelerated depreciation) have given way to a more robust market price discovery regime of competitive bidding (reverse auction). This transition from early 2017 saw greater transparency in the determination of wind tariffs; however, the uncertainties regarding the new framework have also sharply reduced capacity addition of onshore wind power. The capacity added has seen a fall from the high of 5502.37GW in 2016–2017 to 1865.23GW in 2017-2018. To achieve the 60GW of wind power targeted by 2022, the Renewable Energy Ministry plans to bid out 10GW wind power capacity each year for 2018–2019 and 2019–2020.

The central government issued new guidelines in 2016 for onshore wind power projects after a gap of around 20 years. The guidelines contain, inter alia, clear timelines for completion of project to prevent land squatting; provisions to ensure installation of international-quality wind turbines compliant with grid regulations; and provisions regarding environmental suitability of wind projects. These guidelines, issued by the central government, are in addition to the wind policies issued by the various state governments. The government also issued the National Offshore Wind Energy Policy in September 2015 with the aim of promoting the country's offshore wind energy potential. The principal agency charged with the development of the sector is the National Institute of Wind Energy (NIWE). Under this policy, blocks are to be allocated through a competitive bidding route and developers are required to enter into seabed lease agreements with NIWE. In addition to allocation of blocks, NIWE is also required to carry out the initial wind resource assessment and assist the project developers in obtaining clearances. Taking steps towards harnessing this enormous potential, the Environment Ministry has given its approval to a wind measurement project in the Gulf of Kutch, near the Gujarat coast, for setting up an offshore data collection platform for survey, investigation, exploration, data acquisition and other related technical studies in territorial waters. Unlike the procurement of solar power, wind power procurement was not done on competitive basis until 2016. Wind tariffs as discovered by competitive bidding in recent years have been as low as 2.43 rupees per kWh.

The government has notified the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Wind Power Projects (Wind Guidelines) with a view to promoting transparent bidding in the wind sector, where traditionally electricity has been sold to distribution companies at the feed-in tariff determined by the relevant SERC. Some key incentives for wind power developers under the Wind Guidelines include that a single bidder will be allowed to bid for a minimum wind project capacity of 25MW, with at least one 5MW project at each site for intrastate projects, while for interstate projects a bidder
will be allowed to bid for a minimum wind project of 50MW at one site. The procurer can also specify the maximum capacity to be allotted to a single bidder, including the bidder’s affiliates. The maximum capacity for a single bidder or company or group of companies can be fixed by the procurer taking into consideration economies of scale, land availability, expected competition time frame, and the market need.

In the offshore wind sector, the government of the India through the NIWE has invited expressions of interest from developers for India’s first offshore wind project. The government aims to develop 5GW of offshore wind capacity by 2022. The government has currently identified the states of Gujarat and Tamil Nadu for development of offshore wind projects.

In May 2018, the government has introduced the National Wind-Solar Hybrid Policy with the main objective to provide a framework for promotion of large grid connected wind-solar PV hybrid system for optimal and efficient utilization of wind and solar resources, transmission infrastructure and land. In this regard, SECI has floated a tender for setting up a 1200MW solar-wind hybrid power project.

**Solar energy**

Solar plants can be set up under the Renewable Energy Ministry’s National Solar Mission (NSM, previously the Jawaharlal Nehru National Solar Mission), as well as under state policies. As is the case with wind energy projects, the accelerated depreciation limit has been reduced to 40 per cent on solar assets. Other incentives such as achievement-based incentives, subsidy programmes and tax benefits continue to be allowed on solar assets.

After successfully implementing both batches of Phase I, and Batch I, II and III of Phase II of the NSM, the Renewable Energy Ministry has issued final guidelines for Batch IV of Phase II of the NSM, which proposes to add capacity aggregating 5,000MW. On the date of writing, several auctions are under way under Batch IV of the NSM. In a departure from Batch II Phase II (but similar to Batch I Phase II and Batch III Phase II), recent bids under Batch IV envisaged procurement under the viability gap funding (VGF) scheme, where the tariff is predetermined and bidders are selected on the basis of the quantum of discount they are willing to accept on the VGF to be provided by the government. The MNRE has issued the Payment Security Mechanism (PSM) guidelines in order to operationalise the payment security fund of 5 billion rupees, through which SECI will cover delays in payment by buying entities towards projects set up on the basis of offered VGF incentives under the NSM.

Giving a major push to the solar power development, especially the large-scale photovoltaic (PV) projects, the government has increased the capacity of solar parks (involving projects of multiple developers) from the existing 20,000MW to 40,000MW. In an ambitious attempt to meet its renewable energy target of 175GW, the Renewable Energy Ministry has proposed development of solar power projects with capacity of 67GW, as well as an integrated solar module manufacturing capacity addition of 20GW. The new plan put in place by the Renewable Energy Ministry provides new annual targets – 17GW to be tendered out by March 2018, another 30GW in the next 12 months and a further 30GW in the subsequent 12 months.

The government has notified the Guidelines for Tariff Based Competitive Bidding Process for Procurement of Power from Grid Connected Solar PV Power Projects (Solar Guidelines) to promote standardised competitive procurement of electricity from solar PV projects and appropriate risk sharing between stakeholders. The Solar Guidelines envisage that standardised bidding documents (i.e., a request for selection, a PPA and a power sale agreement) will be prepared pursuant to the guidelines; these documents are expected to
be in place over the next couple of months. The Solar Guidelines also provide several other incentives for solar power developers such as better payment security terms (a revolving letter of credit for one month of billing, payment security fund or a state government guarantee with an amount equivalent to three months’ billing), handover of land (90 per cent of land within one month from execution of the PPA) for solar parks and compensation to developers in situations where the project is available to supply power but the grid is unavailable.

On the domestic manufacturing front, the sector suffered a setback in 2016 when the World Trade Organization (WTO) ruled against the inclusion of certain domestic content requirements (DCR) in the tenders under the NSM. The guidelines under the NSM had prescribed certain DCR to promote local manufacturing capability and attract efficient and advanced technology. In response, the United States raised a dispute at the WTO following failed consultations regarding the DCR for solar cells and modules (having once challenged the requirements under Phase I as well). It has claimed that the requirements (although for a portion of the total capacity) are in violation of India’s international trade obligations, as they discriminate against foreign suppliers. The WTO in its findings, stated that India’s DCR are trade-related investment measures, thereby violating the Trade Related Investment Measures Agreement and provisions of the General Agreement on Tariffs and Trade (GATT) by providing less favourable treatment within the meaning of GATT. India appealed the WTO’s decision before the WTO Appellate Body, which was rejected. Following the WTO ruling, the government has since restructured the Solar Guidelines to remove DCR related obligations. In another related development, the government has rejected a proposal to implement anti-dumping duties against imported solar cell technology. This decision of the Renewable Energy Ministry acknowledging that the current capacity of domestic manufacturing is inadequate to meet the targets for solar capacity addition, and focusing on growing the market first before promoting domestic manufacturing, has been hailed as highly pragmatic and investor-friendly. There are currently ongoing trade investigations for the imposition of safeguard and anti-dumping duty on import of PV cells and modules. The Ministry of Finance has proposed a provisional duty of 70 per cent for 200 days on solar cells and modules. However, this proposal has received resistance from the Indian manufacturers in the sector who propose to file a petition in relation to investigations over the past year. To further address issues regarding additional taxes being imposed on solar power projects (in terms of components or services), the Renewable Energy Ministry has explicitly clarified that a protection under change in law provisions will include a change in the rates of applicable taxes, duties and cesses. This move is expected to decrease the uncertainty around tariffs becoming commercially unviable on account of increase in taxes. However, the imposition of safeguard duty (currently 25 per cent ad valorem) on solar panels imported from all countries, except for developing countries other than Malaysia and China has resulted in a slowdown in import of solar panels in the country.

To combat global warming and climate change, the International Solar Alliance (ISA), which is a partnership of more than 120 solar resource rich countries (now open to all UN countries), was officially launched in 2015 with its headquarters in India. The objective of the ISA is to create a coalition for addressing the special energy needs and capacity building among the member countries in a collaborative manner. More than 70 countries, including India, have signed the Framework Agreement to see the ISA becoming an intergovernmental body under the UN charter. India has been chosen as the host country of the ISA and a framework agreement between the Ministry of External Affairs, Government of India and
the ISA has been signed in March 2017. This framework agreement gives the ISA a juridical personality and gives it power to contract, acquire and dispose of movable and immovable properties, to institute and defend legal proceedings in India.

In addition to setting up solar generation capacity through solar power plants and solar parks, various states are also looking to promote the setting up of both grid-connected and off-grid solar rooftop systems. The government launched a US$750 million subsidy scheme for rooftop solar projects to provide close to 30 per cent of the capital subsidy required. The government has already allocated around US$90 million in subsidies to various states in the country. In a bid to further encourage the use of solar rooftop systems, the government has recently exempted customs and excise duty on materials used in solar rooftop systems. Additionally, state governments are promoting the installation of such systems by introducing enabling legislation, such as net metering regulations. Solar Energy Corporation of India, which is a central government company under the administrative control of the Renewable Energy Ministry, issued a tender for 1,000MW capacity for the development of grid-connected rooftop solar capacity, utilising the rooftops of central government ministries and departments, reduced to 500MW after reassessment of the potential capacities of all the government ministries and departments.

**Biopower and waste-to-energy projects**

The Renewable Energy Ministry has proposed to launch the National Bioenergy Mission (along the lines of NSM) to boost power generation from biomass by facilitating capital investments and reducing use of fossil fuels.

In the context of municipal waste-to-energy projects specifically, there is significant scope in Indian cities for business; however, several challenges are being faced by ongoing projects. While there is opposition on account of environment and health hazards for the communities living in proximity to these projects, and low quality of waste because of lower calorific value, the government is trying to promote schemes to encourage cities and municipalities to take up waste-to-energy projects in PPP mode. Recently, India launched its largest waste-to-energy plant in Delhi, which will consume 2,000 metric tonnes of waste every day and shall generate 24MW of energy. The revised tariff policy mandates power distribution companies to buy 100 per cent of the electricity generated from the waste-to-energy plants in their respective states. The MNRE has issued a scheme in May 2018 where central financial assistance will be provided to bagasse based co-generation projects at the rate of 2.5 million rupees per MW and non-bagasse based co-generation projects at the rate of 5 million rupees per MW.

**Energy efficiency and conservation**

To institutionalise energy conservation efforts, the Energy Conservation Act 2001 was enacted and the Bureau of Energy Efficiency (BEE) was established under the Ministry of Power in 2002. Periodic energy audits have been made compulsory for power-intensive industries under the Energy Conservation Act.

The National Electricity Policy affords high priority to energy conservation and demand-side management through the BEE. To further enhance efficiency in thermal power projects, the Revised SBDs specify the station heat rate at which the power stations must be operated, failing which the developer is heavily penalised by a decrease in the fixed charge.
Additionally, the CERC tariff regulations provide for operational norms such as reduction in heat rate for existing bigger units, linking of allowable heat rate to design heat rate, tightening of working capital norms, and norms on reduction in secondary fuel oil consumption.

iii Technological developments
The National Electricity Policy envisages special efforts being made for research, development demonstration and commercialisation of non-conventional energy systems. Further, it envisages the gradual introduction of efficient technologies (such as super-critical technology and integrated gasification combustion cycle) for generation of electricity. It also requires cost-effective technologies to be developed for high-voltage power flows over long distances with minimum possible transmission losses.

iv Connectivity of renewable energy
In 2018, the CERC substantially revised the procedure for connectivity for renewable energy sources by issuing the Procedure for making application for Grant of Connectivity in ISTS, as approved by the CERC on 15 May 2018 (Procedure for Renewable Connectivity) and amending the connectivity regulations. The Procedure for Renewable Connectivity was introduced to address concerns of pre-booking and squatting of connectivity bays by entities, which leads to under-utilisation of connectivity bays and restricts connectivity to genuine connectivity applicants.

VI THE YEAR IN REVIEW
In the past few years, the government has continued to introduce a spate of reforms across the energy spectrum, backed by swift executive action, which have enthused stakeholders in a hitherto stagnating market. The mainstay of the Indian electricity market over the past financial year has been the promotion and stabilisation of the renewable energy sector, with the introduction of competitive bidding in the wind and solar sectors that have witnessed a significant lowering of tariffs. With capacity addition of about 62GW in renewables alone, the Central Electricity Authority currently estimates that there is no coal-based capacity addition required until 2022, especially given that about 50,000MW of coal-based projects are currently under construction in the country. On the distribution front, the UDAY scheme has outlived its initial push to distribution licensees, with distribution companies focusing on operational inefficiencies (transmission and distribution losses, metering and collection issues) to lessen the financial burden on them. With the strengthening of the law governing insolvency in India, there is a significant risk of power sector assets being brought before the NCLT for insolvency proceedings.

The Reserve Bank of India has recently withdrawn several debt restructuring schemes and is in the process of strengthening the norms and procedures for declaration of non-performing assets. This would mean greater accountability for power producers and perhaps an increase in insolvency proceedings being initiated for entities in the energy sector.

In the transmission sector, giving a boost to large-scale transmission projects – which includes setting up the ‘green energy corridor’ to provide for additional large-scale renewable energy capacity – the government has launched the National Smart Grid Mission (NSGM), with a broad aim of planning, implementing and monitoring all the smart grid projects in the country. Through the NSGM, the government plans to develop smart microgrids by using...
state-of-the-art technology to monitor and control power flows. However, renewable energy project developers believe that the current grid infrastructure is inadequate to complement the rapid growth witnessed by the renewable sector.

In the nuclear power sector, India’s failed attempt to gain membership of the elite Nuclear Suppliers Group despite an unprecedented diplomatic push has been a major setback to India’s aim for energy security and combating climate change. India’s commitment to reduce its dependence on fossil fuels, and to ensuring that 40 per cent of the country’s energy requirements are met from non-fossil fuels, requires a significant ramp-up in nuclear power production. There were certain concerns of suppliers and manufactures of nuclear material and equipment who feared the possibility of exorbitant liability being passed on to them by an operator under the Civil Liability for Nuclear Damages Act 2010 in the event of a nuclear accident. The government of India has clarified that while the legislation would not be amended, it was not mandatory to include a civil liability clause in the contractual arrangements between the foreign supplier and the Indian operator. Critics are of the view that the government’s interpretation of the law is problematic in that liability will not be traced back to a supplier of nuclear equipment or material as they would rarely agree to a civil liability clause when it is not mandatory under Indian law. However, to allay the concerns of suppliers regarding their liability, the India Nuclear Insurance Pool, with a capacity of 15 billion rupees, was launched by Indian insurance companies. It provides coverage to operators and suppliers for any nuclear liability towards third parties.

At the international policy arena for energy sector, India has been successful in being at the forefront of the ISA, which is an Indian initiative and could help India in aligning its energy ambitions in the future. India has also joined the International Energy Agency this year as an associate member, which would help India to move to the centre stage of the global energy dialogue and to better represent the interests of the emerging markets. India also houses the headquarters of the ISA and is at the forefront of activities proposed by the ISA.

Under the Tariff Policy, solar RPO was fixed to 8 per cent by 2022 and the renewable generation obligation on thermal power plants were introduced, which has been well received in the renewables market. While the introduction of the once promising system of RPOs and RECs resulted in a market where supply of RECs greatly outstripped demand on account of non-enforcement of RPOs, recent amendments by the CERC to the floor and ceiling price of solar RECs has resulted in a marked rise in the number of solar RECs traded on the market, albeit at the floor price. Further, the Supreme Court has made it mandatory for industries with captive power plants to procure a percentage of their energy from renewable sources and empowered the SERCs to impose penalties on units that failed to fulfil its obligations, which has further shored up the REC market.

The government has been striving for increase in production of renewable power through the use of advance technology by proposing installation of ‘ultra-mega solar power projects’, and through innovative solutions to capitalise on abundant solar energy by proposing solar parks along canal banks and solar power-driven agricultural pump sets and water pumping stations. The government has also proposed feeder separation to augment power supply to rural areas, and to strengthening transmission and distribution systems.

The tariffs determined by the competitive bidding process for the procurement of solar power have fallen steeply over the past few years, with India achieving record low tariff of US$0.035/kWh in solar power bids. India achieved its record-low tariff of US$0.044/kWh in the bid for a 750MW solar PV project at the Rewa Solar Park in Madhya Pradesh, which is one of the largest single-site solar projects in the world. Industry experts are attributing such
a low tariff to the overall project design, with bidding documents that were largely seen as developer-friendly owing to provisions such as state guarantee, identified buyers and deemed generation benefits. The government has also given a massive thrust to increase the share of wind energy in the overall installed energy capacity of the country by introducing various policy initiatives in the past few years in the wind energy sector that include the introduction of bidding in the wind energy sector; the Re-powering Policy; the Draft Wind-Solar Hybrid Policy; the New Guidelines for Development of Wind Power Projects, etc. Further, the promotion of solar rooftop projects by various state governments is a discernible trend, with a number of states issuing net metering regulations and upgrading local grids to match the growth of the solar rooftop sector. The introduction of competitive bidding guidelines in the wind and solar sectors has led to a fresh impetus in the provision of better risk allocation, which has led to greater investor confidence and significantly lower tariffs.

As regards interstate scheduling and forecasting obligations for wind and solar plants, the CERC amended the Indian Electricity Grid Code and Deviation and Settlement Regulations, making scheduling mandatory for wind and solar plants with a capacity of over 50MW. The deviation settlement mechanism, which has replaced the unscheduled interchange mechanism, allows scheduling with a plus-or-minus 15 per cent range, with penalties payable by the generators for exceeding the permissible range, based on the tariff under their respective PPAs. To complement the interstate regulations, several states, such as Andhra Pradesh, Maharashtra, Telangana, Karnataka and Gujarat, have issued their draft intrastate scheduling and forecasting regulations. On the natural gas front, welcome signs for beleaguered gas-based power plants include the significant fall in the price of gas following the bi-annual revision of gas prices under the New Domestic Gas Pricing Guidelines, and the diversion of gas from fertiliser plants to standard power stations in coastal states. In 2014, the government announced that it would lay an additional 15,000km of natural gas pipelines on a PPP basis; however, this proposal has not materialised due to lack of financial viability.

One key development revolves around the Supreme Court’s decision to deny compensatory tariffs to various power producers whose power plants are lying idle, underutilised or facing delays on account of a change in the Indonesian coal pricing regime. In 2014, the CERC and certain SERCs found that the difficulties faced by such power producers were genuine, and sought to provide relief to these power producers in the form of a ‘compensatory tariff’, to compensate the losses suffered and additional costs incurred by them. However, the Appellate Tribunal for Electricity (APTEL) in its judgment in 2016 held that the CERC does not have jurisdiction when it comes to varying or modifying tariffs or granting compensatory tariffs in cases where a tariff has been determined through a tariff-based competitive bidding route. The APTEL did state, however, that the CERC would have the power to grant relief in the event that a force majeure or change in law were to be established. The Supreme Court has set aside the order of APTEL and held that the change in the Indonesian coal pricing regime is neither force majeure nor change in law as per the PPA. However, the Supreme Court held that the amendment to the New Coal Distribution Policy in 2013 would be considered as change in Indian law, and that the power projects that have been impacted by the shortfall in domestic coal supply due to such amendment may be compensated as per the change in law provisions in the PPA. In this regard, the Supreme Court has asked CERC to take a fresh look at the matter to determine the relief that should be granted due to the change in Indian law, if any. However, the coal sector is unlikely to be a key focus area for the government given the current energy mix in the country, and estimates that coal based capacity need not be added till 2022 at the least.
In the oil and gas sector, the government has approved a policy for extension of production-sharing contracts for oil blocks granted prior to NELP to enable and facilitate investment to extract the remaining reserves by advanced technologies. Bidding for oil and gas blocks is also being conducted under the OALP, which adopts all features of HELP such as reduced royalty rates, no oil cess, uniform licensing system, marketing and pricing freedom, and exploration rights for full contract life.

VII CONCLUSIONS AND OUTLOOK

The government has tackled policy reform in the energy sector with enthusiasm and aggression, bringing about significant key changes with the aim of increasing the bankability of power projects. The government’s policy reforms reveal a clarity of vision and a push for stability in the energy sector with a renewed commitment to non-conventional sources of energy. This is apparent from the government’s aim of restructuring financially stressed distribution companies, bringing consistency in all the standard bidding documents for procurement of power, and introducing a new pricing regime for natural gas coupled with the shift to HELP. In respect of renewable energy, the new government is making significant strides by introducing key incentives for solar and wind power producers, a push for rooftop solar plants and ultra-mega solar power plants. The recent regulatory and policy changes made in the energy and infrastructure sector are indicative of the fact that the government is committed to greater transparency and openness in the sector, with most of the procurement moving towards a competitive bidding regime. The judicial authorities are also taking a serious look at irregularities and inconsistencies in government policies and awards, which is evidenced by landmark judgments by the Supreme Court, including in the coal block deallocation cases, compensatory tariff cases and the CCI’s decision to levy a penalty on CIL.

However, there are persisting concerns, such as inadequate transmission infrastructure to support growth of renewable energy and lack of affordable financing. While the policy reforms have led to an initial spurt in capacity addition, achieving India’s aim of energy security is quite a way from being accomplished. That said, although the government seems to gaining some ground, it will require continuous and persistent reforms over the coming years to ensure that India achieves its ambitious targets in the energy sector.
Introduction

The Energy Regulation and Markets Review included a chapter on Iran for the first time in 2016, when the conclusion of the Iran deal and the subsequent reopening of the country to foreign investors and companies promised a new period of potential transformations for its energy sector. Following the implementation day and the partial lifting of the sanctions, Iran’s energy sector, having previously lagged behind compared to other countries as a result of decades of isolation, saw moderate progress. The US withdrawal from the multiparty international agreement in 2018 affected the continuation of that progress, insofar as it concerned foreign investment. This chapter aims to be a practical and useful business tool, and therefore focuses and analyses recent changes and developments; looks ahead to expected trends; provides an overview of the key entities in the Iranian energy sector; and looks ahead to the likely future developments in the Iranian energy sector. We provide a short summary of key aspects of the Iranian legal system to be aware of, and key considerations for operating or establishing an energy business in Iran.

Overview

Iran’s energy sector has been affected and constrained by US sanctions since the 1979 Iranian Revolution, and UN sanctions since 2006. These have hampered development and progress for a country that was otherwise a key player in the energy sector. Economic sanctions affected this sector in another manner as well. They impelled Iran to develop a strong home-grown industry capable of developing and operating assets that were for the most part independent from foreign and global players.

As with other jurisdictions that have sought to transform a state-dominated energy sector into a modern industry capable of attracting significant private capital, Iran has had to deal with issues arising from that transformation, not least of which were the cross-subsidisation and artificially depressed energy prices. However, the prize is large. Both

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1. Shaghayegh Smousavi is a partner at CMS Hasche Sigle.
2. Iran holds the world’s fourth-largest proved crude oil reserves (accounting to almost 10 per cent of the world’s reserves) and the world’s second-largest natural gas reserves. The country ranked ninth in total primary energy production and 10th in total primary energy consumption in 2014. The US Energy Information Administration (EIA), Iran country profile, updated 19 June 2015. Retrieved from https://www.eia.gov/beta/international/analysis_includes/countries_long/Iran/iran.pdf.
the size of the Iranian energy sector and its influence in the region is expected to grow. Energy prices are significantly lower and energy consumption significantly higher than international and regional averages.

This, together with the relaxation of sanctions against Iran in 2016, opened up opportunities in a potentially significant market for Western power and renewables companies in spite of the lingering effect of sanctions as well as those that were still in force, most notably those prohibiting US companies from engaging in transactions involving Iran. In 2018, the US re-imposed sanctions, including those targeting Iran’s energy sector that had previously been lifted under the JCPOA.

III SANCTIONS REGIME: KEY CONSIDERATIONS

On 14 July 2015, the Guardian Council of the Islamic Republic of Iran approved a multilateral nuclear agreement as consistent with the country’s constitution and Islamic law. Pursuant to the agreement between Iran and the permanent members of the United Nations Security Council (China, France, Russia, the United Kingdom and the United States), plus Germany and the European Union (referred to as the E3+3) the International Atomic Energy Agency (IAEA) confirmed to the UN Security Council on 16 January 2016, formally known as Implementation Day, that Iran had complied with the programme set out in the Joint Comprehensive Plan of Action (JCPOA). In return, the E3+3 lifted the nuclear-related sanctions on the same day.

While the EU and UN nuclear-related economic and financial sanctions were terminated, some sanctions remained in place and were not affected by the nuclear deal, in particular sanctions related to human rights, proliferation and support for terrorism. The major sectors that were affected by this initial phase of sanctions relief included the energy sector.

In May 2018, the Trump administration withdrew from the JCPOA. Following the withdrawal, two wind-down periods were introduced; by the end of each certain sanctions were to be re-imposed in full effect. The 90-day wind-down ended on 6 August 2018 and the 180-day wind-down period ended on 4 November 2018. Consequently, sanctions on Iran’s energy sector were re-imposed on 5 November 2018.

In response and as part of an attempt to ensure that other signatory parties to the JCPOA would be able to implement its terms, the EU updated the Blocking Statute (originally adopted in 1996 in response to US sanctions against Cuba), adding the US sanctions against Iran to the regulation’s scope. The statute prohibits EU persons from complying with the extraterritorial sanctions, except where granted permission by the EU Council, while also giving them the right to seek compensation for damages caused by implementation of those sanctions.

In another attempt aimed at facilitating trade with Iran and protecting European businesses against US sanctions, Germany, France and the UK (E3) established the Instrument in Support of Trade Exchanges (INSTEX). INSTEX is a special purpose vehicle, based in

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Paris, whose shareholders are the E3 governments and which has therefore a certain level of sovereign immunity. Not yet operational, its initial focus is expected to be on humanitarian trade with Iran (i.e., those activities that are exempted from US sanctions). Other EU and non-EU countries have reportedly expressed an interest in joining INSTEX.

Iran’s local counterpart needed to operate with INSTEX, called the Special Trade and Finance Institute (STFI), was established on 20 March 2019.

Eight countries were granted waivers exempting them temporarily from sanctions. This is apart from one-off waivers given to some countries on an individual basis such as the United States granting Turkey a 25 per cent exemption from sanctions on Iran, or Iraq receiving a sanction waiver for importing gas and electricity from Iran. To this end, Fuji Oil, jointly with Showa Shell Sekiyu loaded the first Iranian crude oil cargo lifted by Japanese refiners since the sanctions’ re-imposition.

The current US sanctions regime, which includes an ever growing list of sanctioned persons and entities, means it is crucial, particularly for EU companies, to conduct due diligence and assess their exposure to the US sanctions and ensure compliance with the remaining EU sanctions before signing business contracts in or relating to Iran. A further risk for investors in the energy sector is the possibility that Iran violates its undertakings in the JCPOA. In such a case, the EU has reserved the right to reimpose sanctions on Iran – the ‘snapback’ provisions. Entities that have contracted with Iranian companies may, therefore, find themselves bound by contracts that they cannot perform.

It should also be noted that Iran, at 128th, ranks low on the World Bank’s Doing Business ranking of economies on their ease of doing business. Key challenges for Western companies, include being alive to the risks of bribery and corruption, as Iran scores high on the Corruption Perceptions Index. Inflation, price control and subsidies reduce proper price discovery and therefore reduce the prospect of merchant projects. A long-term lack of investment in infrastructure means that delays can arise from limitations imposed by wider infrastructure development needs.

As with other energy markets that have opened up in recent years, a common strategy for Western companies is to partner with a local (in this case Iranian) entity that can guide them through the domestic landscape (see Section IV on joint ventures with Iranian entities). However, initial experience has been that cultural and other barriers can make the process of effective partnering often difficult and, while it is important to know your counterparty well, reliable information on Iranian companies is not always straightforward to procure.

IV OVERVIEW OF THE OIL AND GAS SECTOR IN IRAN

Iran’s oil and gas industry was looking to attract something close to US$200 billion over five years in investment to capitalise on the opportunities presented by the opening up of the

6 See also: https://www.ecfr.eu/article/commentary_trading_with_iran_special_purpose_vehicle_how_it_can_work.
7 Ibid.
sector following Implementation Day. The timing was perhaps unfortunate, with oil prices languishing without immediate evidence of an imminent recovery. Nevertheless, the costs of production in Iran were estimated to be significantly lower than the international average, and well below the low current oil price. In these circumstances, Iran has been pushing ahead with reforms to further open up its oil and gas sector to foreign investors.

On 1 October 2015, in response to criticisms of the previous buy-back contracts, the Iranian cabinet endorsed a new upstream oil and gas document known as the Iran Petroleum Contract (IPC).\textsuperscript{10} The purpose of the IPC is to facilitate foreign investment. The document consolidates the previous model agreements into one, and covers the exploration, appraisal and development phases.

The general terms and structure of the contractual framework of Iran’s upstream oil and gas was ratified in September 2016. This ratification finally took place with many amendments after political discussion.\textsuperscript{11}

The nature of the IPC was, from the beginning, a controversial issue. This is because Articles 77 and 125 of the Iranian Constitution require that international agreements have parliament’s approval. However, it has been previously held that contracts in which one side is a government entity or company and the other side is a privately owned foreign company are not international agreements subject to Article 77. The criticisms also seem to rely on Article 45 of the Constitution, which requires state control of major industries and large mines (including oil and gas reservoirs).\textsuperscript{12} The IPC seeks to navigate the constitutional position by avoiding a production-sharing structure, and does not create ownership rights in reservoirs for foreigners. The contract is more akin to a risk service contract arrangement, with an exploration phase of four to six years, an appraisal phase of two years and a development phase of 20–25 years. The Oil Ministry supervises operations and the government-owned NIOC retains ownership of reservoirs, assets and extracted commodities. As NIOC remains responsible for oil exploration and extraction, and as all operations under the IPC are carried out on behalf of NIOC, all the assets, including equipment, wells, etc., belong to NIOC.

In contrast to the previous buy-back approach, the IPC provides for a joint-venture model, among other things, to allow collaboration and technology transfer, with decisions escalated to a committee comprising representatives of NIOC and the international oil and gas company (IOC). If oil is discovered and economical to extract then NIOC and IOC establish a joint operating company or joint venture to take implementation forward and develop, operate and produce from the field. Decisions would continue to be made through a joint committee. Further Iranian ownership participation in the company is also possible. This is a fundamental opportunity as foreign IOCs have not been able to be involved in oil production in Iran since the Revolution in 1979.

Nevertheless, the IPC sought to attract IOCs from across the world – such as Total, Statoil, BP, Royal Dutch Shell, OMV, Wintershall, Repsol, Sinopec, as well as companies from Asia and the Middle East region – to its sector by providing attractive terms. These include a form of hedge against oil price volatility, with payments where there are significant changes in oil price, and providing some protection on risks relating to the ability to develop a field. This contrasts with the previous buy-back arrangements under which payments were linked to capital costs (typically providing a return of 15–17 per cent) and did not incentivise

\textsuperscript{10} See http://rc.majlis.ir/fa/law/show/944062.
\textsuperscript{11} ‘Iran’s Cabinet Approves IPC’, NIOC, 6 August 2016.
\textsuperscript{12} See https://www.reuters.com/article/us-iran-oil-contracts-idUSKCN12K1M1.
additional recovery in oil or account for changes in oil price. Among other things, the IPC also moves away from the previous approach under the buy-back arrangements that capped cost recovery and required the IOC to take all delay and cost-overrun risks. While costs will be recoverable under the IPC, costs and annual budgets are to be jointly agreed under a collaborative approach. The IOC would effectively take all exploration risks in the event that exploration and production targets are not met.

Also, notwithstanding ownership remaining with NIOC, the IPC could in some situations allow reserves to be booked, which is important for IOCs in terms of demonstrating their market value. The IOCs would take the risks on the costs of operation. As noted, there is also an emphasis on a collaborative approach in the IPC and a requirement on knowledge transfer into Iran.

Putting aside the single IPC-based agreement concluded with a local company, Iran signed a US$4.8 billion deal with a consortium led by French oil company Total in July 2017 to develop the South Pars gas field in cooperation with China National Petroleum Company (CNPC). In March 2018, Russia’s state-owned oil company Zarubezhneft signed a trilateral deal with the National Iranian Oil Company and Dana Energy Company for the development of the Aban and West Paydar oilfields near the Iran-Iraq borders. This is the second major energy deal signed in Iran since the lifting of international sanctions. Once Total failed to obtain a waiver from US sanctions against Iran, it announced that it would withdraw from the project in South Pars gas field. According to the Ministry of Petroleum, CNPC has replaced Total in phase 11 of South Pars.

Another development in oil industry was the reintroduction of the option to purchase oil and petroleum products in the Iran Energy Exchange (IRENEX) allowing the Ministry of Petroleum to sell crude oil and petroleum products at a competitive price in the international ring of IRENEX. IRENEX was initially established in July 2012 with the licence of the Supreme Council of Securities and Exchange. It works under the supervision of the Securities and Exchange Organization and operates with the aim of organising and supervising the trade of energy carriers, providing non-discriminatory and fair access of trading platforms. From October 2018, in different rounds of the supply, crude oil has been purchased via IRENEX.

V OVERVIEW OF THE POWER SECTOR IN IRAN

The Iran Electricity Regulatory Board (IERB) was established around the turn of the millennium. Its work is overseen by the Minister of Energy and it often works with external third-party consultants. It comprises an executive, called the Regulatory Board Secretariat, which runs a Logistics Unit, a Judicial Unit, a Market Process Planning and Scheduling Unit, and a Market Monitoring Analysis and Adjustment Unit. The IERB is responsible for monitoring, researching and supporting the electricity market, and suggesting regulations and electricity-related tariffs to the IERB. The IERB also has a role in maintaining an orderly functioning of the industry by managing relationships between industry participants. It is also

13 Iran’s Oil Ministry signed a US$2.2 billion worth agreement with Tadbiri Energy group, affiliated with the Execution of Imam Khomeini’s order company (EIKO), which was responsible for increasing the recovery rate of three fields (Yaran, Kupal and Marun).
empowered to manage claims arising between such entities. When making recommendations on regulatory changes and similar matters, the IERB may consult stakeholders and take into account comments and recommendations from industry.

Historically, Iran’s electricity market was a local, private and vertically integrated monopoly in Tehran, starting in 1905. An early Law of Iran Electricity Organisation was passed in January 1963, creating regional electricity companies, and followed by the establishment of the Ministry of Water and Electricity in 1964 (the Ministry of Energy since 1975), generally regulating the electricity sector. A year later, legislation was introduced that required all non-governmental electric companies to accept mandatory retail tariffs. As these tariffs proved to be below cost, a subsidy was required to maintain the companies as solvent and the companies in due course became Ministry subsidiaries.

The Generation and Transmission Company of Iran (Tavanir) was established in 1970, primarily to implement transmission and generation plans, and operate generation facilities and the transmission network. Today, Tavanir has been restructured to be the holding company responsible for these activities.

Pursuant to the decision of the Iranian High Administrative Council, dated 18 December 2004, ‘all legal missions and activities regarding new energies (renewable) and all affairs regarding policymaking, planning supervision and supporting the relevant activities in the non-public sector shall be concentrated in the Ministry of Energy’.

The Iran Grid Management Company (IGMC) was formed in 2004, following the establishment of a wholesale electricity market for the trading of electricity by the IERB. The IGMC acts as the market and system operator.

An impediment to private sector participation has traditionally been Article 44 of the Iranian Constitution, which required all large-scale industries and power generation (among others listed) to be fully state-owned. In 2004, this article was amended to require the state to cede at least 20 per cent of control of power companies to private and ‘cooperative’ entities. This has led to a privatisation process in relation to this element of the generation sector (except in relation to ‘must run’ plant) and this privatisation process remains ongoing.

There is a wholesale electricity market in Iran (referred to as the IEM) comprising a day-ahead market for generators and retailers (typically the regional electricity companies) to buy and sell power. A power exchange and bilateral contracts sit alongside the market. Tavanir remains responsible for exporting power to neighbouring countries. However, as there is limited competition in the market, it functions as a fairly basic auction mechanism. Bids are submitted to offer power at specified prices. Purchasers of power specify quantities required. The market operator, IGMC, then clears the market. Generators are paid for capacity even if they are not successful in the bids to provide power to incentivise the provision of capacity to the market. The maximum bidding price is capped by regulation.

Private generators can contract to sell power bilaterally to purchasers via the power exchange or through futures contracts for power delivery. These prices are privately set and not subject to regulatory intervention. Power sold in the power exchange is excluded from

18 For further information on the power sector, see www.igmc.ir.
19 For further information on the IEM and power exchange and trading arrangements, see further on www.igmc.ir.
the day-ahead market. On a longer-term basis, generators and purchasers of power can also contract long-term power purchase agreements at a negotiated price. Trades are then notified to the system operator, IGMC.

Despite considerable hydroelectric and renewables capacity, Iran remains significantly reliant on thermal and gas generation, with thermal power plants’ 15,829MW and gas plants’ 25,919MW accounting for 20.1 per cent and 33.9 per cent of the total installed capacity respectively by the end of the previous Iranian year (21 March 2018).\(^\text{20}\) The power system and the use of energy in Iran are both notoriously inefficient, principally because of cross-subsidies, ageing infrastructure and lack of investment in advanced technologies. There is a plan to shift away from such implicit subsidies to ones that are targeted to fuel poverty. On technology and capital requirements, the focus remains on attracting foreign direct investment despite the imperfect sanctions position, volatility in the market, political uncertainties and the residual risk of a snapback occurring on sanctions.

In terms of policy, the current Sixth Five-Year Economic, Cultural, and Social Development Plan for 1396-1400 (2016–2021) has established a target of 5 per cent of the country’s total energy generated to come from renewable sources by the end of the Plan, projected to equal 5GW. Owing to the overall effects of partial lifting of sanctions and the new policies in the renewables sector, Iran has become an increasingly attractive market for foreign investment. Mindful of the need to compensate for the hold back of the sanction years, the government has been pursuing a policy shift with a view to systematically incentivise the deployment of renewable energy, to establish a revised and more stable regulatory regime under the Renewable Energy and Energy Efficiency Organisation of Iran (SATBA (formerly SUNA)),\(^\text{21}\) and to offer feed-in tariffs that are nominally high when compared internationally.

Among the incentives is a purchase scheme for any electricity produced from renewable sources (solar, wind, biomass, geothermal, small hydro power plants, and more recently fuel cells and turbo-expanders) established by the Ministry of Energy for a recently increased period of 20 years.\(^\text{22}\)

The current feed-in-tariffs that have remained in force since 2016 vary between 3,400 to 4,200 rials/KWh in the wind sector, and 3200–4900 Rials/KWh in the solar sector, based on the capacity of the plant-taking into account the adjustment factor, namely inflation. Under this scheme, more than €3 billion are expected to be invested in the renewable sector.\(^\text{23}\)

The success of the new tariff regime, which led to a 70 per cent growth in development of renewable power plants between March 2016 and March 2018, plus another 30 per cent by March 2019\(^\text{24}\) had encouraged a continuance along the same path.

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\(^\text{21}\) An Act passed by the parliament in December 2016 merged SUNA with the Iran Energy Efficiency Organisation (SABA). According to the act, all functions, obligations and authorities of SUNA, as well as its personnel will be transferred to the new organisation, called SATBA.

\(^\text{22}\) Prior to July 2015, contracts were limited to a five-year period and did not differentiate between technologies.

\(^\text{23}\) Statement by the president of the SATBA: https://www.isna.ir/news/97081407155/.

For the time being, the Iranian contractual practice is based on the PPA model, a new and partially revised version of which is to be publicly announced within the coming months. However, an additional tender-based system for large utility-scale RES projects is also under examination.

Key points in the PPA include, among other points:

a. while the PPA provides for a conditional purchase price, this price may be decreased if the project is delayed in commissioning;
b. the possibility of an increase in the purchase price if locally made equipment is used;
c. the seller is responsible for any work concerning the design, construction, testing and commissioning of the grid connection facilities;
d. the purchaser has no responsibility for connecting the plant to the grid: any expenditure in connection with these rests with the seller;
e. the seller is responsible for obtaining all applicable permits at its cost. However, the purchaser has an obligation to assist the seller in obtaining the required permits;
f. the purchaser to provide a revolving letter of credit (LC) from an Iranian bank, with a validity period not less than six months and a value equivalent to the amount to be paid by the purchaser. The expenses associated with the LC shall be shared between the purchaser and the seller;
g. the PPA is governed by Iranian law, with a dispute settlement mechanism requiring, first, negotiation, then referral of the dispute to an expert and, finally, to a court;
h. where changes in law provisions require an adjustment to the PPA terms and the changes are a result of new decrees and directives, any additional expenditure shall be borne by the purchaser;
i. force majeure provisions allowing, upon the request of the seller, the performance to be suspended for a period of six months, without any payment. If not remedied within the period of six months, the purchaser may terminate the contract; and
j. termination rights in the event of certain circumstances arising, such as insolvency, assignment without consent by the seller, or loss of required permits (subject to cure periods).

A key question for the success of the new tariff regime, in particular in respect of large-scale projects and bankability issues, in general, will be the availability of project finance. Linked to the bankability of the PPA, will be the question of availability of sovereign guarantees or another structure, such as a standing fund, as a backstop for payments over the long term.

The decline of the Iranian currency in the past year imposed an additional challenge on projects that had foreign financing. The adjustment formula used in the PPA is based on the official euro to rial exchange rate. Whereas this official exchange rate was kept unchanged throughout the year, the secondary market rate, which was the only rate available to project owners for converting their income to foreign currencies, fluctuated drastically. The difference between the two had an impact on project owners’ income and their ability to pay back their loans. In response to voiced concerns, officials reviewed proposals to amend the PPA adjustment rate. The amendment was not yet in force as of May 2019.

Another development was the adoption of a resolution of the Ministry of Energy, allowing the export of electricity from renewable energy resources in the Iranian calendar year beginning on 21 March 2019.

Obtaining all required licences, concluding a PPA with the buyer followed by a transit contract with the SATBA are prerequisites for export. Operation of the power plant and
the transit contract will be supervised by the SATBA. During the contract term, the plant is obliged to observe all the export regulations and must pay the royalty and transit fee to the SATBA. Before operation activities, the applicant is required to conclude a support contract for transit and export of electricity with IGMC and determine all the conditions and requirements, including the costs and compensations, for a five-year period.25

VI LOOKING AHEAD: COMPETITION IN THE IRANIAN POWER AND OIL AND GAS SECTORS

Ultimately, whether competition is introduced into Iran’s energy sector will depend on the outcome of an ongoing debate between conservatives arguing for energy independence and self-sufficiency, and moderates (led by President Hassan Rouhani and his administration since he first took office in 2013) looking at the best way to promote and advance the economy. With the energy industry having been in public hands during the era of sanctions, with significant involvement of the Islamic Revolutionary Guard Corps (IRGC), there are significant vested interests to overcome in the industry, and any opening up of the sector could be viewed with suspicion by the IRGC and Iran’s home-grown energy sector supply chain, particularly as the reforms promise to fundamentally redefine and rescope the role of NIOC and bring in substantial foreign investment and technology.

Introducing competition and tariff reform has a number of potential benefits for the energy sector in Iran. The purpose of such reforms is to ensure that the risks associated with investments in the energy sector are allocated to the entity that can best manage them and also to force better investment decisions. Competition and liberalisation seeks to transfer greater performance risk to the private sector, harness the benefits of competition by introducing new technology and international best practice into the sector, and share financial gains with taxpayers and consumers.

Where the Iranian Ministry of Energy is also the regulator and direct investor in the power sector, the conflicts of interest can be significant. For effective regulation, a separation of key aspects of the state from the sector holds many benefits. However, Iran may wish to take a staged approach to liberalisation of the sector, to ensure that the process does not place undue upward pressure on energy prices (which can be politically difficult) or pressure on existing entities to reduce costs that create financial difficulties and unsettle the sector.

Competition will also require capacity-building in key institutions that will need to manage the capabilities and expertise in managing new market processes, as well as educating the full supply chain on the approach in Iran. Key elements that Iran may need to consider include establishing an independent transmission company and considering which entity should procure new power generation projects (as well as potentially other types of projects in the sector). A key goal is to make electricity a liquid commodity that can be traded in spot markets and wholesale markets. Where Tavanir is restructured, a regulated price control also needs to be established for the network and monopoly businesses, and the process for setting the initial tariffs involves considerations including ensuring adequate revenue, promoting efficiency and driving key policy objectives.

Iran does already have independent power projects and a number of power plants have been privatised or are scheduled to be privatised. For international investment, the sustainable PPA offered by Iran is designed to create a predictable revenue stream to facilitate the raising

of finance and protect independent power projects from political risk. Also, perhaps most importantly, there has to be a clear ability for international investors to rely on the legal ‘sanctity’ of contract terms and pursue international arbitration. The existing Iranian PPA needs to be improved to provide a sustainable PPA framework and to be bankable according to international standard if international investments are to materialise. Further, while competitive procurement of new large-scale projects is usually the recommended approach, it is often the case that initial projects are not competitively procured and instead are procured on a negotiated basis.

Policy and sectoral changes in Iran will also create a question on how to deal with power purchase agreements held by existing power projects in Iran, which may not have contemplated significant market changes. As a basic principle, it will be important for Iran to honour existing contract terms and maintain confidence in the pipeline of projects. Any other approach would have an effect on market liquidity and could create above-market costs, as well as deter new entry and inhibit the gains associated with competition and market opening. They could also lead to claims and litigation. While it is worth making an effort to integrate independent power producers (IPPs), the magnitude of IPP contract terms affected can be a factor in the approach taken.

Iran is also looking to develop further its role as a major regional participant in the Middle East power market and this will be enhanced as it takes steps to implement arrangements drawing from international best practice and that are appropriate to the Iranian context.

VII ESTABLISHING AN ENERGY BUSINESS IN IRAN AND DISPUTE RESOLUTION

While it is beyond the scope of this chapter to detail the broader considerations on the appropriate form of investing or establishing a business in Iran, the recent opening up of the Iranian market means that this is a very relevant topic for entities wishing to become involved in the Iranian energy sector.

Investors, developers and supply chain entities looking to operate in the energy sector in Iran post-Implementation Day (see above) will need to decide on the form of their engagement and entry into Iran. Many entities will operate from overseas, some will consider opening up a branch office in Iran and, for more involved operations, an Iranian legal entity may need to be established or dealt with. Branch offices tend to be used typically for activities such as marketing, aftersales and certain service provision activities. However, engagement in direct commercial activities would affect the tax treatment of branch offices. Longer term and deeper operations would tend to be pursuant to the establishment of Iranian companies, such as a private joint-stock company or limited liability company. Alternatively, another route for engagement in Iranian projects is to set up a joint venture with a local entity. The joint venture could then participate in tender rounds, and this can also help on meeting local content requirements.

A foreign investment licence under the Foreign Investment Promotion and Protection Act (2002) permits the foreign investor to incorporate a company without restriction on the level of foreign ownership. It is possible, following changes to regulations that came into effect in 2008, to incorporate a fully foreign-owned entity for specified activities.

A further useful consideration is to establish a business in a free trade zone (FTZ) such as Anzali, Aras, Arvand, Chabahar, Makoo, Kish or Qeshm. Existing and planned FTZs in
Iran are subject to the Law on the Administration of Free Trade and Industrial Zones 1993. Each FTZ has an authority that manages the activities in the zone and issues permits. While FTZs look to streamline and ease the process of establishing a business in Iran and may impose attractive tariffs and customs duties to act as incentives, as noted above the recent changes following the Foreign Investment Protection and Promotion Act (2002) make it viable for foreign entities to establish wholly owned businesses generally in Iran. Iran’s 29 Special Economic Zones (SEZs) may also be a viable option for some foreign entities looking to establish themselves in Iran, and they provide many of the advantages associated FTZs.26

The FTZs are distinct from the SEZs, the difference is geographic: FTZs are established in border regions while SEZs can be set up anywhere on the mainland.27 In contrast to the FTZ, SEZs are considered as part of the mainland according to Iranian legal terms.

Furthermore, the law and regulations governing the FTZs are different from those applicable to SEZs. For instance, no visa is needed to be obtained beforehand to enter into the FTZs (visas are issued on arrival), but in the SEZs, entrance of foreigners is subject to mainland regulations.28 In addition, in the FTZs, applying for investment is subject to the relevant FTZ regulations, whereas the law of the mainland remains applicable in the SEZs.29

As such, it is important for entities looking to enter the energy sector in Iran to understand the broad array of laws, regulations and industry frameworks currently in effect in Iran. The Constitution of the Islamic Republic of Iran requires all laws and regulations to be based on Islamic criteria. Iran has two coexisting systems of law, namely the law of Islamic lawyers and codified law. It is beyond the scope of this chapter to provide a detailed overview of the Iranian legal system. We set out below some aspects of particular note in conducting transactions in the energy sector.

Iran has promoted foreign participation through the Foreign Investment Promotion and Protection Act (FIPPA), 2002. According to FIPPA, sectors including industry, mining, agriculture and services in greenfield and brownfield projects are open to investment in Iran subject to satisfaction of certain criteria.30 Foreign direct investment (FDI) may be admitted in fields where private sector activity is permitted. However, purely commercial activities are not considered to be foreign investment.

Therefore, foreign investors may choose the investment method in the project as FDI or foreign investment in all sectors within the framework of ‘civil participation’, buy-back and build-operate-transfer schemes.31

A licence for foreign investment under FIPPA is issued by the Organization for Investment Economic and Technical Assistance of Iran (OIETAI).32 The licence provides for foreign investment to be treated on a par with Iranian investments,33 allows for disputes to be resolved outside Iran and also allows for the repatriation of profits. It, generally, facilitates investment and secures against non-commercial risks including currency transfer.34

26 See www.freezones.ir.
27 ibid.
28 ibid.
29 ibid.
30 Article 2 FIPPA.
31 Article 3 of Implementation Regulation of FIPPA.
32 Article 15 of Implementation Regulation of FIPPA.
33 Article 8 FIPPA.
34 Article 4 of the Implementation Regulation of FIPPA.
nationalisation, expropriation,\textsuperscript{35} government intervention and breach of contract by government.\textsuperscript{36} As to the major questions of expropriation and nationalisation of foreign investors’ assets, FIPPA recognises the right to receive immediately compensation based on the fair market value of the expropriated assets on the day before expropriation takes place.\textsuperscript{37} Besides, foreign investors have direct access to and possibility of withdrawal of export proceeds out of escrow accounts established in banks outside Iran.\textsuperscript{38} Foreign investors may export their goods and services without any commitment to reintroduce export proceeds into the country.\textsuperscript{39} Also, travel for foreign investors, directors, experts and their immediate family in relation to the investment covered by FIPPA is made easier by the grant of a three-year multi-entry visa, a residence permit, a work permit for each individual with a right of entry and a three-month residence permit on each occasion.\textsuperscript{40} Furthermore, all bilateral investment treaties concluded with other countries contain a provision whereby they are only applicable to investments for which the FIPPA licence is acquired.

According to statements from the OIETAI officials, foreign investment applications are processed within 15 days, although, in practice, such a process can take up to 30 days to complete.\textsuperscript{41}

The FIPPA licence validity can be extended upon request by the foreign investor (for example, if the foreign investor fails to bring in the investment capital within the determined period and needs an extension). Otherwise, the licence will be considered null and void.\textsuperscript{42}

In the renewable energy sector, applications for foreign investment licences are submitted to the OIETAI, once the necessary permits have been obtained from the SATBA.

In addition to the judiciary (court) system, the settlement of disputes through other methods such as arbitration has been recognised by the Iranian legislator and has developed significantly in recent years. This is aided by the considerable experience derived from the example of the Iran–United States Claims Tribunal and the work performed by different institutions providing specialised services in arbitration matters.

National arbitration in Iranian law is governed by the 2000 Civil Procedure Code (Articles 454–501). For international arbitration, a framework was established by the Iranian Law on International Commercial Arbitration of 1997. To complete the efforts in furthering the position of international arbitration under the Iranian legal system, Iran has ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958.

There are two major arbitration bodies in Iran: the Tehran Regional Arbitration Centre, 2004, and the Arbitration Center of Iran Chamber, 2001. As is standard in international arbitration, there is no right of appeal against an award. A party may, however, apply to have an award set aside on certain grounds.

\textsuperscript{35} Article 9 FIPPA.
\textsuperscript{36} Article 17 of the Implementation Regulation of FIPPA.
\textsuperscript{37} Article 9 FIPPA.
\textsuperscript{38} Articles 13–18 FIPPA.
\textsuperscript{39} Articles 13–18 FIPPA.
\textsuperscript{40} Article 20 FIPPA and Article 35 of the Implementation Regulation of FIPPA.
\textsuperscript{41} Article 6 FIPPA.
\textsuperscript{42} Article 32 of the Implementation Regulation of FIPPA.
As far as arbitration of disputes relating to public and state property is concerned, particular attention should be given to cases where the subject matter concerns public and governmental property, or if a party is foreign, since the approval of the Consultative Assembly (the parliament) is also required in such cases.43

VIII CONCLUSIONS AND OUTLOOK

The easing of sanctions marked the beginning of a new chapter in the Iranian energy sector, characterised by increased determination for progress and ambitious goals for development on the part of the Iranian government accompanied by higher, if still somewhat cautious, interest from the foreign investors’ side.

The re-election of President Hassan Rouhani in 2017 was a positive sign that the policy path already taken to incentivise foreign investment in the Iran energy sector will be continued over the next two years. Despite the progress made, financial challenges still persisted as valid concerns.

However, the turbulence caused by the current US administration’s policies towards Iran and the aftermath of the withdrawal from JCPOA has taken a toll on the energy sector and the wider economy. It now remains to be seen whether and how the efforts initiated by the current administration aimed towards attracting large-scale foreign investment while also localising know-how in the energy sector will continue in the coming year.

Nevertheless, it is undeniable that Iran, with its vast energy resources and all its potential, remains a significant player in the energy sector.

43 Article 139 of the Iranian Constitution provides that:

The settlement, of claims relating to public and state property or the referral thereof to arbitration is in every case dependent on the approval of the Council of Ministers, and the Assembly must be informed of these matters.

In cases where one party to the dispute is a foreigner, as well as in important cases that are purely domestic, the approval of the Assembly must also be obtained. Law will specify the important cases intended here.
I OVERVIEW

Certain key historical and constitutional matters

Prior to 2003, when the government headed by Saddam Hussein was replaced, Iraq was governed by a socialist-leaning government with a very limited private sector in place. This has continued to be the case since the overthrow of the monarchy in 1958 and, with various exceptions, continues to be the case today. A series of steps were taken by the various republican governments that nationalised the principal components of the economy, culminating in the 1972 nationalisation of the oil sector. Iraq had therefore become a centralised economy, with various ministries controlling most aspects of the economy.

Between 1980 and 1988, Iraq was involved in a war with the Islamic Republic of Iran, which was followed in 1990 by the invasion of Kuwait and the subsequent Gulf War I. Immediately after Kuwait was invaded, a series of UN Security Council resolutions imposed sanctions on Iraq, which were followed by a series of nationally imposed sanctions. These sanctions were widespread and extended into most imports, including key oil and gas and technological imports.

Following Iraq’s expulsion from Kuwait, the sanctions continued (until 2003), but more importantly, the central government lost effective political and security control over a significant portion of Iraq, to be referred to as the Kurdistan Region. In 2004, the Transitional Administrative Law (the Interim Constitution) recognised the boundaries of the Kurdistan Region, with the same boundaries adopted in the Permanent Constitution of 2005 (the Constitution). The Constitution was structured in a way that provided limited powers to the central government and shared certain powers between the central government and regional governments (the Constitution provides that other regions could be formed). All remaining powers are to be vested in the regional governments.

The matter of oil was hotly debated in the constitutional process, with a compromise reached that provided that the existing fields continue to be managed by the central government, and new fields are jointly managed with the revenues going to the central government. However, in the event of a dispute between the central government and the regional government over the development of new fields, the general view is that the position of the regional government would prevail. Issues relating to gas are treated in the same way. The Constitution further provided that Iraqi oil and gas is owned by the Iraqi people, and that the management of the oil fields is to be based on a federal oil and gas law that, to date (14 years after the Constitution was approved), has not been passed.

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1 Salem Chalabi is a partner at Stephenson Harwood Middle East LLP.
There have been disputes between the Kurdistan Regional Government (KRG) and the central government on a number of oil and gas issues, in particular the methodology relating to the development of new oil fields, as well as the revenue from such the sale of oil produced from such fields. The KRG has entered into production-sharing agreements with a substantial number of oil companies, agreements that the Iraqi Ministry of Oil (MOO) has been critical of. As a result of these disputes, the MOO has claimed on a number of occasions that the KRG has been selling its oil directly in the oil markets (through Turkey) and keeping the income from such oil sales. In response, the KRG has claimed that the central government has withheld amounts owing to it in the budget and accordingly it has to sell crude oil produced in the Kurdistan fields to finance its expenditure. Despite certain interim deals, the disagreements between the central government and the KRG continue at the time of writing. These continuing disagreements have led to various court and arbitration claims in various jurisdictions. These disputes have also involved the Republic of Turkey in connection with disputes relating to the Iraq-Turkey export pipeline, from which both Iraqi and Kurdish crude is exported to Ceyhan, Turkey.

In light of the constitutional separation of powers between the central government and the KRG, the electricity sector is effectively two separate sectors: one for the areas governed by the central government, and the other governed by the KRG. Each has developed in a different manner over the past few years.

ii Developments in 2014

The year 2014 saw two key developments: the takeover of certain parts of Iraq by the Islamic State and the drop in the price of oil.

In June 2014, the Islamic State took over significant areas in Western and Northern Iraq, such as the cities of Mosul, Tikrit and parts of the governorate of Tikrit. These areas were mainly governed by the central government, and therefore the central government was unable to continue providing electricity services to those areas that fell to the Islamic State. Simultaneously, in the governorate of Kirkuk, the Islamic State took over certain oil fields and was able to sell crude oil directly. Ultimately, troops belonging to the KRG were able to take back some of these fields, which are now under their control. Constitutionally, these fields are to be managed by the MOO (through North Oil Company) but, following certain negotiations, the KRG was unwilling to hand these back to the MOO, and is now operating the fields itself. This has increased tensions between the central government and the KRG.

As for the drop in oil prices, the impact had affected the Iraqi budget in 2014 significantly, and therefore the MOO was required by the parliament to consider amending the terms of its existing service contracts with the existing international oil companies. To that effect, it looked at different alternatives to propose to the international oil companies. However, in 2016, it decided to maintain the structure of the contracts, at least for the near future.

iii Developments in 2015

The year 2015 saw several developments that affected the energy sector, in particular the continued drop in oil prices, which affected the Iraqi economy significantly. On the positive side, there were various offensives against the Islamic State that ended up with the recovery of certain towns and cities that had fallen to the Islamic State, including Tikrit and Al-Ramadi. These victories were coupled with an almost total destruction of the capacity of the Islamic State to produce oil from fields under its control.
In order to address significantly reduced oil revenues, the Iraqi government significantly reduced its expenditures, in particular its capital expenditure on infrastructure projects. The impact of such reduced infrastructure expenditures on the growth of the Iraqi economy has not been positive as projects stalled, causing significant arrears to Iraqi companies and, more importantly, to international oil companies. The latter, accordingly, began to reduce their expenditures in the oil fields under the technical services agreement.

iv  Developments in 2016

The year 2016 was a year in which the fiscal consolidation that commenced in 2015 became more entrenched, but was also a year in which Iraq engaged with the International Monetary Fund in a Stand-By Arrangement (SBA).

As oil prices dropped further in early 2016, the government decided to commence negotiations with the International Monetary Fund (IMF) for an SBA programme that would not only lead to loans from the IMF of US$5.4 billion over a three-year period, but also would unleash facilities from the international community for a total of approximately US$18.6 billion over a three-year period. The IMF programme was premised on three pillars:

a  the maintenance of sustainable debt over the next five years;

b  the repayment of arrears as well as the non-incursion of new arrears;

c  the maintenance of decent levels of central bank reserves; and

d  the reduction of Iraq’s non-oil primary deficit.

In order to achieve these goals, a principal condition precedent was that the MOO was required to become current on its arrears to the international oil companies by the end of 2016 (which it did). The IMF programme also required a restructuring of the Iraqi economy away from a state-controlled economy and also towards increasing non-oil revenues.

Throughout 2016, the government was able to stabilise its expenditures. However, it was also required to carry out an audit of all of its arrears, which it was able to do. These proved to be larger than expected and therefore Iraq’s investment expenditures, including those in the oil and electricity sectors, were required to be reduced.

At the same time, the MOO began to consider some new large-scale investment projects, including the Basra-to-Aqaba pipeline. Moreover, there have been proposals relating to the refinancing of some large infrastructure projects, in particular, the Karbala refinery (which is no due to be completed in 2021).

v  Developments in 2017

The year 2017 saw a number of major developments in Iraq on a number of fronts. First, the government was able to recapture all of the territory that had been held by the Islamic State in previous years, including the city of Mosul. This allowed for large-scale returns of refugees to their homes, although there are still a large number of refugees in camps (in particular in Kurdistan). However, it also clarified the enormous requirements in order for Iraq to rebuild its destroyed infrastructure (with the estimated needs being US$50–90 billion). Second, and more closely linked to the energy sector, following a referendum in the Kurdistan region and disputed areas in September 2017 that was opposed by the central government, the central government recaptured the city of Kirkuk and the majority of adjoining oil fields (which had been under the control of the Kurdistan regional government from late 2014). The effect of this was twofold. First, the exports of oil from the Kirkuk fields (approximately 300,000 barrels per day) effectively stopped. Second, as a result of such stoppages, the revenues of the
Kurdistan regional government from oil exports declined dramatically and the Kurdistan regional government began to face a very difficult financial situation. Since the budget deal between the central government and the Kurdistan regional government had not been implemented since 2015, the halt in oil revenues from the sale of Kirkuk oil has reduced the revenues of the Kurdistan regional government by over 60 per cent. Discussions between the two parties commenced but, by the end of 2017, no new deal had been reached.

In 2017, Iraq also completed its first real entry into the international financial markets. In January, it sold US$1 billion in bonds guaranteed by the United States Agency for International Development. This was followed in August by an offering of US$1 billion in unguaranteed bonds. The average interest rate was approximately 4.5 per cent. The banks who arranged the offerings for the Republic of Iraq were Citibank, Deutsche Bank and JP Morgan. Iraq also commenced a series of transactions with export credit agencies to complete various projects in the electricity sector, with support coming from UKEF, SACE, Euler Hermes, SERV and EKN. This is being followed by other financings for other sectors.

vi Developments in 2018

The year 2018 saw a large number of developments in both the economic and the oil and gas sector. These included:

a As a result of the fiscal requirements of the IMF, which Iraq was unable to meet (in particular spending cuts), Iraq in effect pulled out of the SBA. The IMF requirements were intended to create fiscal space for Iraq to be able to spend on the reconstruction efforts and on infrastructure.

b A reconstruction donor’s conference was held in Kuwait in February, during which several billion dollars were pledged in different forms to Iraq. Unfortunately, due to a number of factors, very little of the pledged money has been paid or invested, leaving the reconstruction problem un-addressed. Both the 2018 and 2019 budgets did not allocate significant funds for reconstruction.

c Parliamentary elections were held in May 2018, with the votes split among a number of blocks, none having any parliamentary control. A clear result was that the Da’awa Party, from which the prime ministers for the years 2006–2018 had come, lost out. Eventually, agreements were reached and a new government, headed by Adel Abdul Mahdi, was voted in.

d The Trump administration’s imposition of sanctions on Iran created a very tenuous situation for Iraq, as approximately 40 per cent of Iraq’s electricity is dependent on Iranian gas. Iraq reacted methodically with respect to this matter but has still to put in place a mechanism to replace Iranian gas in due course.

II THE IRAQI ELECTRICITY SECTOR

i The Ministry of Electricity – Baghdad

The Iraqi Ministry of Electricity’s (MOE’s) role in the electricity sector is, to say the least, all encompassing, with it being the principal policy maker, power producer, service provider, regulator and operator. As with most other ministries in Iraq, the MOE is beset with bureaucracy and corruption, and therefore is not conducive towards structural innovation and reform. The senior staff of the MOE are, by contrast, technically trained to a good standard and have significant knowledge of technical developments in the electricity sector.
The legislative basis for the MOE is currently vague, which has made it difficult to clarify its powers. Accordingly, the MOE’s powers are somewhat broad in the power sector. In recent years, however, it (together with the various arms of the executive branch) has prepared two drafts of an MOE law. In late 2016, the draft law was passed. The following is a brief summary:

- The MOE is designed to organise the electricity sector in Iraq, including the introduction of the private sector into the generation and distribution sectors. In connection therewith, one of the goals of the law is to transfer the electricity sector from a purely public enterprise to a mixed or private sector enterprise.
- It is also designed to make the electricity sector less centralised (with everything controlled by the office of the Minister of Electricity), by among other things encouraging the role of the provincial governments.
- It is designed to encourage renewable energy.

Administratively, the MOE is currently divided into various central departments (generation, transmission, distribution, etc.) and various regional departments (e.g., south generation). The passing of the law, which has not yet been fully implemented, has at the time of writing not amended too much administratively within the MOE. In an effort to carry out the above, the electricity law keeps more or less the same central departments within the ministry (generation, transmission, distribution, etc.) but then plans to convert the regional departments into public companies. In total, there will be 10 such separate public companies (mirroring the existing departments now). The idea is that assets of each of the departments would be transferred to the relevant public company. Ultimately, the law proposes that these companies would be converted into publicly owned companies (listed on the Iraq Stock Exchange). The issue to be considered is that, absent appropriate revenues from electricity, these companies would continue to make losses and therefore would be unable to be privatised.

The law also contemplates opening private investment opportunities in the electricity sector. These include the introduction of private companies in the electricity distribution sector, which will charge tariffs. This could be a problem for such companies and for the MOE. In early 2015, the MOE announced the introduction of higher tariffs to be paid by the consumers. (Currently, only a small percentage of consumers pay what they actually consume in electricity, principally because of meters that are old and have been tampered with, corruption in the collection of electricity bills (which are manually collected) and rewiring of home electricity lines.) The introduction of higher tariffs caused public uproar as the public at large felt that the new tariffs would be unduly burdensome at a time of economic hardship, an uproar that was picked up on by powerful political actors who ended up opposing the new tariff. The MOE was therefore forced to withdraw this proposal. Later in 2016, as part of Iraq’s entry into the IMF SBA, the Iraqi cabinet voted on a resolution that reintroduced higher tariffs. These new higher tariffs were structured to be less strenuous on the poorer elements in Iraqi society. Transferring this task to the private sector may work better, as the private sector may prove less responsive to political pressures; but at a time in

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2 The Ministry of Electricity (MOE) was established during the time of the Coalition Provisional Authority (2003–2004). Prior to that, the various components of the MOE, which were organised as state-owned enterprises, were part of the Ministry of Industry and Minerals. Once the MOE was established, such state-owned enterprises were de facto converted into directorates of the MOE.
which electricity shortages and cuts are the norm, the public at large may not favour such a move. In 2016, the MOE embarked on a pilot programme in a neighbourhood in Baghdad to privatise distribution and collection of electricity tariffs. This programme was followed by a wider plan, announced in the form of a ‘request for information’, for privatising the collection of electricity tariffs throughout the country. By early 2017, the tariff collection programme was introduced into several areas, although there have been demonstrations against the introduction of the programme in cities such as Basra. Since then, the privatised tariff collection programme has had very limited success and the MOE is currently reviewing the programme.

The law has the right intentions, but it suffers from some of the same legislative basis that makes it difficult for the private sector to flourish in Iraq. Or rather, although the draft law itself may have the right incentives, there are a large number of legal and regulatory hindrances that make it difficult for the private sector to carry out business in Iraq. For example, there is a law in Iraq (Law No. 56 of 1977) that provides that the government or any governmental entity need not obtain judicial decisions prior to attaching private assets if they are seeking to recover their debts. Coupled with the fact that Iraq is not party to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, such laws make it very hard for international financial institutions and investors to feel comfortable doing business in Iraq generally.3

ii The private sector in the Iraqi electricity sector

There were significant developments in the private sector entering the electricity business in 2014. First, however, by way of background, there are a few matters to keep in mind:

a The Iraqi transmission and distribution network is owned completely at this stage by the MOE. There is no direct private ownership interest in the transmission and distribution sector. The MOE, in conjunction with the World Bank, has indicated that it intends to privatise these two sectors, although no concrete steps have been taken in connection with it. Accordingly, other than as mentioned above with respect to the attempted privatisation of the collection of electricity tariffs, the only private sector involvement in transmission and distribution has been in the fulfilment, construction and implementation of MOE procurement orders.

b In 2010–2011, the MOE conducted a tender for four independent power producer (IPP) projects in the generation sector, using GE Frame 9E turbines that had been recently acquired by the MOE (and which it was to sell to the winning bidders). The total of these projects combined was 2,750MW. However, owing to certain structural difficulties, in particular to do with the supply of fuels (the MOE did not want to assume the risks of supply and requested that the developers enter into separate supply agreements with the MOO), there was little or no international interest in these tenders. Accordingly, only local companies bid (with some international participation in the consortiums) and, with one exception, these bidders had no experience of the IPP sector. Shortly after the bids were analysed by the MOE’s IPP team, a new minister

3 Recently, in an effort to ensure a more advantageous dispute resolution venue for international investors, Iraq joined the International Centre for the Settlement of Investment Disputes, which is a part of the World Bank.
was appointed who was not in favour of these projects. He therefore cancelled the tendering process, and ran tenders to award these as engineering, procurement and construction contracts.

In late 2013, the Iraqi cabinet instructed the MOE to commence negotiations with three independent Iraqi companies to develop independent power plants in Iraq. In February 2014, the Iraqi cabinet passed resolution 90 of 2014, authorising the MOE to enter into power purchase agreements with these three companies, pursuant to which these companies were to develop up to 9,000MW. Some of the locations were allocated in the cabinet resolution. In particular, one of the developers was to develop a 3,000MW power plant in the Al-Rumailah area of the Basra Governorate, while another developer was to develop a 1,500MW power plant in the Besmaya area south of Baghdad (adjacent to a new real estate development project), subsequently extended to 3,000MW. In April 2014, two of the developers entered into heads of terms with the MOE and the National Investment Commission to develop combined cycle plants, which were followed in June 2014 with the execution by the MOE of power purchase contracts with these two developers.

In late 2015, two further projects were entered into with one developer. These projects, one of which is in Al-Rumailah and the other in Shatt Al-Basra, are somewhat uniquely structured. They involve the expansion of open cycle power plants to combined cycle power plants, with ownership of the open cycle power plants remaining in the hands of the MOE and ownership of the steam turbine portion of the plant remaining in the hands of the developer, with the developer operating the whole plant. This structure has many of the characteristics of a build-operate-transfer structure. Although negotiations have been completed with respect to these two projects, at the time of writing, there are various practical and technical matters that are still being discussed.

In late 2016, a fourth developer, Raban Al-Safina, entered into a power purchase contract to develop a 750MW combined cycle plant in the Maysan Governorate in Southern Iraq. This company was also granted the right to expand one open cycle power plant to a combined cycle power plant, with a capacity of 250MW.

From a regulatory perspective, key issues facing these projects include the following:

- There have been difficulties in transferring the land to the projects. Again, by way of background, the vast majority of land in Iraq is owned by the Iraqi Ministry of Finance (MOF), which has been somewhat reluctant to transfer land (even by way of lease) to developers of various projects, including electricity projects. Other government entities have followed the lead of the MOF. This matter has proved to be a hindrance to private investment in Iraq in general.

- Although a grid code has been developed by the MOE, which the companies have been willing to comply with, in practice this has not been tested by the private sector and it seems certain integrating difficulties are being experienced at the early stages of these projects.

- The companies have covenanted to comply with the environmental laws and regulations in Iraq, which have generally been developed by the Ministry of the Environment. The process will entail the projects having to obtain environmental licences from the Ministry of the Environment, which grants these after conducting an examination similar to a Phase I environmental impact study. However, the Ministry of Environment is not very experienced in the electricity sector and has not developed specific regulations for this sector. In practice, therefore, at this stage, environmental compliance is still untested.
and, since the financing of these projects are not contingent on international project finance, one is not sure whether these projects would comply with the World Bank Group Environmental, Health and Safety Guidelines.

d Learning from the experience of 2011, the MOE has assumed the obligation of providing fuels to these companies. The MOE is looking at ways of securing these fuels, including the natural gas that Iraq lacks. Although both the MOO and the MOE are experienced with respect to the laying out of pipelines (and have processes for usage of the land on which the pipelines may be located), difficulties could arise in particular due to the security situation in certain parts of Iraq. Certain difficulties have also arisen with respect to the supply of water, in particular with respect to the needs of steam turbines (in the combined cycle power plants).

e The cabinet further approved the issuance by the Ministry of Finance of payment guarantees to the developers, which are the international norms for such power purchase contracts. These payment guarantees have been issued and, to date, they have been accepted by the lenders to these projects.

f The tariffs were agreed between the cabinet and the developers, and therefore were not left for market forces. These tariffs were not divided into capacity charges and output related charges, but one tariff was agreed for the production of each of the simple cycle and the steam turbines productions. These tariffs have since become the benchmark, although there are new tenders in various stages of development that could impact these benchmarks.

g As the first two projects are groundbreaking projects, the licensing processes have not been tested out and are not fully clear. The National Investment Commission established a one-stop shop mechanism to assist in moving matters forward, but this has not been successful. As a result, there have been substantial delays in every single step. Indeed, Iraqi bureaucracy is stultifying. For example, in discussing with international oil companies the difficulties that they face, near the top of the list is always the matter of obtaining visas. Whereas in most developed countries, the process for obtaining visas is a relatively simple process, the Iraqi Ministry of Interior intentionally makes things difficult, ostensibly for security reasons.

The first IPP in the electricity sector, in the town of Besmaya, near Baghdad, commenced production in the second quarter of 2017, and by the end of the year it was producing approximately 1,500MW. The plant is currently producing 2,500MW. Another power plant, in Al-Rumaila, Basra Governorate, is currently producing approximately 840MW.

As these new projects move forward and get implemented, Iraq would be faced with a significant portion of its power generation sector in private hands, and with the MOE paying significant sums for electricity under the various power purchase contracts. However, the transmission and distribution side of the grid requires significant upgrade to be able to receive the additional generated power. Accordingly, at this stage, the focus is on moving forward with the transmission and distribution side of the electricity sector.

There is significant potential for investment in the transmission and distribution side of the electricity sector; yet, at this stage, there is no regulatory framework for this. Accordingly, the MOE continues taking steps to improve its transmission grid, which it owns. The plans to privatise this sector have not been adopted, despite proposals introduced by international experts. As for the distribution sector, Iraq is still reliant on old technology, with little
introduction of more modern technologies such as smart meters. Having stated this, in 2013, the MOE launched a pilot project for smart meters; but this was a pilot project that was not very clearly part of a structured plan.

At a time when Iraq is facing serious budgetary difficulties, the MOE tried unsuccessfully to launch tariff increases but had to withdraw them in some areas owing to political pressures. This leaves Iraq collecting very low levels of income from its electricity generation (with significant subsidies going to loss-making state-owned enterprises belonging to the Ministry of Industry and Minerals). In connection with the stand-by arrangements with the IMF, the issue of electricity tariffs and their collection is being addressed, as non-oil revenue is required to increase.

Coupled with this, the lack of natural gas and, due to the mature state of the refineries, limited availability of refined products, Iraq imports refined products and increasingly uses other less efficient products (such as heavy fuel oil) to fuel its generators. The imports of products such as diesel (which fuels a large number of small production generators) ends up exacting even more pressure on the state budget. Electricity, therefore, continues to be a major drain on the state budget.

iii The Ministry of Electricity – Kurdistan

The evolution of the electricity sector in the Kurdistan region has been somewhat different. As it became apparent that the central government’s generation capacity was not going to meet sufficient demand in the areas under central government control, the KRG decided to develop its own generating capacity and, realising it had limited funding to do so, requested that the private sector do so. In addition, the KRG took over the existing grid and began to develop it. In doing so, it relied on the existing central government grid code and practices.

In 2007, the KRG entered into its first power purchase agreement with Mass Global, a private sector company owned by a reputable Kurdish businessman for the development of a 500MW plant in Erbil, which is the capital of the Kurdistan Region. Although this power purchase agreement was designed on a similar basis to international standards, its terms were more favourable to the developer. As the power plant was implemented quickly, the KRG entered into two other power purchase agreements, each for 500MW, with the same company to develop generation plants in the other two major Kurdish cities – Suleymaniyah and Dohuk. As these plants were also set up quickly, it became apparent that demand had increased and therefore the capacities of each of these plants was significantly increased. At the time of writing, the International Finance Corporation acquired from Mass Global a portion of the project company operating the Suleymaniyah power plant. In addition, the KRG entered into power purchase contracts with other developers more recently.

The critical issue for the development of these plants was that the KRG assumed responsibility for bringing natural gas to these plants, and it did so from one of the undeveloped natural gas fields in the Kurdistan Region, the Khor Mor field. Lacking money, it entered into development arrangements with a Sharjah-based company, Dana Gas, in order to develop the fields. Dana Gas carried out the development and was able to supply, through self-funded pipelines, the natural gas to the various power plants. This was one of the success stories of the KRG, in that not only were untapped gas deposits utilised but they were done so to bring power to the Kurdistan Region, which currently has 24 hours of electricity a day. However, a dispute arose between Dana Gas and the KRG, which went to arbitration, and in November 2015, Dana Gas was victorious in the arbitration and was awarded approximately US$2 billion in damages. In addition, due to the budgetary difficulties faced by the KRG,
owing to its dispute with the central government (over the division of oil revenues) and lower oil revenues in general, the KRG has begun to default on certain financial obligations. It is unclear how that will impact on its obligations under the power purchase contracts, as well as its ongoing relationship with the gas suppliers.

III THE IRAQI OIL SECTOR

i The Ministry of Oil

In federal Iraq, Iraq’s Ministry of Oil administers the oil sector. Under the Constitution, Iraq’s oil belongs to the people of Iraq. With respect to the upstream sector, the constitution provides that existing fields will be managed by the federal government, whereas new fields will be jointly operated by the federal government and the regional governments – and in the event of a dispute, the prevailing view is that it is the regional government that has the decision-making powers. Accordingly, with respect to new fields in the Kurdistan region, the KRG’s interpretation is that it has the power to manage fields. The constitution goes further and provides that exports are to be coordinated by the central government’s apparatus (i.e., the State Organisation for Marketing Oil (SOMO)). Relying on this interpretation, the KRG passed an oil law in the Kurdistan region, providing that the KRG can enter into production-sharing agreements with international oil companies developing and operating new fields in Kurdistan. The agreement between the central government and the KRG at the time was that the oil being produced in the KRG would continue to be marketed and sold by SOMO, and that the central government would pay an agreed share of the expenditures in the budget to the KRG. Over the past few years, there continued to be disputes between the KRG and the central government over the appropriate payments to the KRG in the budget, and therefore, with the exception of a short period in late 2014–2015, this budget agreement has not been implemented. The KRG has therefore continued to export oil through the pipeline in Turkey. After the Islamic State took over large areas of Iraq in 2014, the Iraqi government pipeline to Turkey was damaged and stopped exporting oil. It had been used to export oil from the Kirkuk fields. The Islamic State was expelled from certain areas around the fields of Kirkuk, which fields were taken over by the KRG. As a result, an agreement between the central government and the KRG was reached allowing the KRG to export oil from Kirkuk and keep the majority of its revenues, together with the revenues from the oil produced in fields in the Kurdistan region. This agreement was changed in 2017 (see Section I.v, above).

The Ministry of Oil, which administers the oil sector, is divided into a number of directorates and companies. The Ministry is run by a Minister, who has four deputies (production, refinery, gas and distribution). The upstream oil fields are each administered by an oil company that is owned by the Ministry. Therefore, for example, the oil fields in Basra are administered by the Basra Oil Company. With respect to the other sectors, for example, the refineries sector, again the refineries are owned by government-owned companies, with ultimate control residing with the deputy minister of oil for refining, reporting to the Minister of Oil.

In 2009, the Ministry of Oil commenced a series of bidding rounds for technical services agreements to develop the oil fields under its control. A number of IOCs won these bidding rounds and entered into technical services contracts with the relevant government-owned
oil company administering the relevant fields. The bidding rounds and the administration of the technical services contracts are carried out by the Petroleum Contracts and Licensing Department.

As for gas, the Ministry of Oil carried out a two-pronged approach. Three gas fields were awarded to bidders under the bidding rounds, although two of the fields were in territories that fell under the control of the Islamic State, leading to their abandonment. These areas have since been captured by the government and the government is considering new approaches to the development of these fields. As for the oil fields, the Ministry of Oil, through the South Gas Company, entered into a joint venture with Shell and Mitsubishi (called the Basra Gas Company) to capture and treat associated gas from three fields – Rumailah, West Qurna I and Zubair. The gas produced by the Basra Gas Company is currently being sold to the Ministry of Electricity. The Ministry of Oil is currently considering other approaches for the capturing of associated gas in other fields, including entering into direct contracts with engineering companies to develop gas-capturing facilities near the fields.

With respect to refineries, the Ministry of Oil carried out and continues to carry out a series of policies. Unfortunately, one of its main refineries (Beiji) fell to the Islamic State and was recaptured in late 2015 (having been badly damaged). Steps are being taken to rehabilitate it although this may take significant time and costs. The Ministry, in reliance on Law No. 64 of 2007 (as amended), which addresses investment in oil refineries, entered into two agreements with private companies (in Maissan governorate and Kirkuk governorate). To date, actual work has not commenced on these projects. The Ministry also embarked on a new 150,000 barrels per day refinery near Karbala, owned by the Ministry, which is currently in the construction phase and is expected to be completed in 2021. Once completed, this refinery would significantly reduce Iraq’s imports of refined products.

In 2018, the Iraqi parliament passed a law establishing the Iraqi National Oil Company (INOC). The company was expected to become operational in late 2018. As envisaged, INOC was mainly focused on the upstream oil sector and was to become the owner of the various government-owned upstream oil companies, as well as SOMO. It was intended that INOC will become independent of the Ministry of Oil, although the legislation provides for significant controls by the council of ministers. However, there were objections to INOC, in particular with respect to the allocation of its income. Various parties, including the Central Bank of Iraq, objected to the law because the way it was envisaged would have meant INOC depleting the foreign currency reserves of the Central Bank. In late 2018, the Higher Federal Court declared that, although the establishment of INOC was legal, there were various provisions of the law that were required to be amended.

ii Energy markets

Development of power markets and contracts for sale of power

At the time of writing, with limited exceptions discussed below, electricity in Iraq is provided by three types of providers – the MOE, one independent power producer and private unregulated owners of generators scattered across the country. The MOE’s supply was discussed above and, owing to the fact that it cannot supply electricity 24 hours a day across the country, there are thousands of private owners of generators who have developed their own neighbourhood grids. These private owners of generators are unregulated and therefore they do not comply with any of the government-imposed regulations. Owing to the general security breakdown in the country, and coupled with the fact that the central government has not been in a position to provide electricity 24 hours a day (especially in the hot summer
months), the government has allowed these private generator owners to carry out their unregulated neighbourhood activities. Generally, there is no uniform pricing mechanism for these private owners, but through conversations with these private participants, it seems that after covering their costs (maintenance and diesel costs), they are making profit margins of 30–40 per cent. The suppliers of diesel are also making similar profit margins, as the risks of supply are significant.

In addition to the above, there is effectively a third limited producer of electricity in federal Iraq: the international oil companies who are producing electricity for their own use. Since these fields have not developed completely, electricity production has not reached its capacity. Under the technical services agreements between the international oil companies with the companies belonging to the MOO, the plants are owned by these government-owned companies (such as the South Oil Company), with the power produced only being used in the relevant oil fields. Although this is not necessarily ideal or efficient, the grid between oil fields is not well developed or integrated, and therefore electricity production is limited to the individual field where such generation plants are located. Again under the relevant technical services agreements, the government counterparty is required to provide electricity or to reimburse the international oil companies for the costs of electricity production. The costs have been relatively high because the international oil companies have been using smaller diesel generators. The regulatory framework for this electricity generation has been very limited, and the MOE is not involved in these activities as its grid is not used. The only regulations applicable are environmental, but these are not applied uniformly.

As for the main power suppliers who have entered into power purchase contracts with the MOE, as indicated above, these companies are not allowed to sell their production other than to the MOE (as buyer under the power purchase contracts). As generation capacity increases over the next few years, it is anticipated that this may change. In the Kurdistan Region, the matter is slightly different. As other private plants have emerged, the KRG is only committing to purchasing a minimum percentage of generated electricity, and the developers are allowed to supply power to third parties, including the international oil companies developing the fields in the Kurdistan Region. The problems with this are mainly related to the grid, as it is still relatively undeveloped and there are technical difficulties in the private sector development. Independent electricity producers in the Kurdistan region commenced supplying power to liberated areas, like the city of Mosul.

**Budgetary impacts**

The reduction in the price of crude oil in 2014–2017 caused major budgetary problems in Iraq, and therefore certain existing obligations of the state were delayed or amended. For example, at the time, there was a discussion that the structure and terms of the technical services agreements between the international oil companies and the MOO would be amended. Moreover, the delays in the development of the oil fields may cause the collection and treatment of the associated gas from the oil fields to be delayed. At the time of writing, however, and based on discussions with personnel from the MOO, the South Gas project with Shell Oil (to gather and treat the associated gas from several giant oil fields) is still on track.
Security situation

The deterioration in the security situation, especially in the western desert areas of Iraq, has caused delays in the development of some of the gas fields in the areas, such as Akkaz. Moreover, the strategic pipeline project to Jordan has also been delayed owing to the fact that there are large tracts of land not under government control.

Additional borrowing

As a result of the budgetary constraints in 2015–2017, Iraq began entering into loans and other types of borrowing in the international financial markets. In addition, various ministries including the MOE entered into vendor-financing agreements for the supply of equipment, in particular for the transmission grid. At the same time, owing to the difficult environment in Iraq (legal, regulatory and security), traditional project finance may not be available and accordingly non-traditional forms of financing would be required to be made available (or more aggressive lenders, such as Chinese financial institutions).

IV RENEWABLE ENERGY

The Iraqi renewable energy sector is still in its infancy, without any significant renewable energy projects in place. At the time of writing, the MOE intends to enter into agreements with two sets of developers for a total of 100MW. The basis of these new contracts are still being negotiated.

V CONCLUSIONS AND OUTLOOK

The Iraqi electricity and oil sectors have significant opportunities. However, there are current obstacles – legal, regulatory and financial (as well as the lack of natural gas and refined products) – that can delay the development of the electricity and oil sectors in Iraq. Coupled with the above is the significant corruption that exists, which makes it reasonable to conclude that development would move at a measured pace.
Chapter 13

ITALY

Andreina Degli Esposti

I OVERVIEW

Since the 1990s, the Italian energy market has undergone an extensive liberalisation process that is still ongoing, with the long-awaited deregulation of gas and electricity retail prices set to come into force in July 2020.

Unlike most of its neighbours (France, Switzerland and Slovenia), Italy shut down its nuclear energy production facilities as a result of the Chernobyl incident in 1986 and the ensuing popular vote in 1987.2

That said, Italy is a country with limited natural energy resources and is highly dependent on imports from abroad, including electricity from French nuclear power stations.

On the basis of the 2018 Annual Report issued by the Italian Energy Authority (ARERA),3 in 2017 the economy grew by about 1.5 per cent (in 2016 it had grown by 0.9 per cent), with the demand for electricity (+2 per cent) and primary energy (+1.5 per cent) following the same trend.

With regards to the electricity market, we have witnessed a 2 per cent increase in demand (compared to the 2.1 per cent decrease registered in the previous year), due to climate change and economic recovery. On the contrary, there was a decrease in both imports (-0.7 per cent) and exports (-16.6 per cent). Said increase in demand was met with a growth in domestic production (+1.8 per cent).

With specific reference to primary energy sources, the use of coal has maintained its downward trend (-11.2 per cent), mostly due to lower exploitation in electricity generation (-10.09 per cent), while the gross domestic consumption of natural gas has risen by around 6 per cent, together with net imports (from 53.47 to 57.04 Mtoe).4

The gross national consumption of oil has also registered a decrease (-0.7 per cent), with transport remaining the main sector of end use.

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1 Andreina Degli Esposti is one of the founding equity partners of Studio Legale Villata, Degli Esposti e Associati.
2 In 2008–2010 the Italian government started a new civil nuclear programme, which was later abandoned following the 2011 referendum.
3 ARERA, Relazione annuale sullo stato dei servizi e dell’attività svolta, 26 July 2018, available at https://www.arera.it/it/relaz_ann/18/18.htm. Please note that, at the time of writing, the forthcoming Annual Report (which provides important and reliable information on the energy market) has not yet been published: it is expected between the spring and summer of 2019. For this reason, the present work will not deal with corporate operations (e.g., mergers and acquisitions) that took place in the past year.
4 Megatons of oil equivalent.
On the other hand, ARERA reports an increase in the production of energy from renewable sources (+2 per cent), with the highly incentivised solar and wind plants leading the market.

It is yet to be seen whether these trends will remain stable in the context of the general economic slowdown registered in the last quarters of 2018.5

II REGULATION

i The regulators

Below is an overview of the main public actors involved in the regulation and supervision of the Italian energy market.

The Ministry of Economic Development

The Ministry of Economic Development (MISE) was formed in 2008 with the merger of the former Ministries of Productive Activities, International Commerce and Communications. It is responsible for policy-making in key sectors of the economy such as industry, trade, energy sources and telecommunications.

The ministerial decrees represent a fundamental step in the law-making process as they set up the detailed rules for administrative procedures and standards in the energy sector.

In addition to the regulatory function, the Ministry directly manages authorisation proceedings in respect of major thermoelectric plants, exceeding 300 MWt.6

Within the organisational structure of the Ministry, there are dedicated offices that address energy issues: the Directorate-General for Hydrocarbons and Geothermal Resources; the Directorate-General for the safety of Energy Infrastructures; and the Directorate-General for Electricity Markets, Renewable Sources, Energy Efficiency and Nuclear Power.

ARERA

Since 1995, the Italian energy market has been subject to the supervision of an independent authority, ARERA (formerly AEEG), whose scope of action was originally limited to electricity and gas, but was later extended to water resources (in 2011), energy efficiency (in 2014) and waste management (in 2017).7

ARERA is tasked with protecting the interests of consumers, promoting competition and ensuring the quality of energy services. Most importantly, it defines tariffs and ensures equal access to energy network infrastructure.

In pursuing these objectives, ARERA is also supported by the Antitrust Authority in order to implement the rules of free competition in the energy market to the greatest possible extent.8

The effectiveness of ARERA’s regulatory and supervisory actions is guaranteed by the power to impose administrative sanctions on market operators that do not comply with energy laws or regulations or the Authority’s resolutions.\(^9\)

Furthermore, ARERA plays an advisory role to the parliament and may issue proposals and reports (for instance, the annual report on the state of the energy market).\(^{10}\)

**The Equalisation Fund for Energy and Environmental Services**

The Equalisation Fund for Energy and Environmental Services (CSEA) operates in the electricity, gas and water sectors by collecting the system surcharges paid by the end users from market operators.\(^{11}\)

CSEA manages the funds through dedicated accounts and subsequently uses them to grant subsidies to businesses based on the criteria set forth by ARERA.\(^{12}\)

**The GSE Group**

The Energy Services Manager (GSE) is a state-owned company that promotes the use of renewable energy sources, mainly through incentives and information campaigns aimed at spreading the culture of environmental protection in the energy field.\(^{13}\)

Pursuant to Legislative Decree No. 79 of 16 March 1999, the GSE set up special-purpose subsidiaries for the management of specific segments of the energy market:

- **a** the Energy Markets Manager (GME) organises and manages the electricity, natural gas and environmental markets,\(^{14}\) in accordance with the principles of neutrality, transparency, objectivity and competition;\(^{15}\)
- **b** the Single Buyer (AU) guarantees the availability of electricity by purchasing the required electrical capacity and reselling it to distributors on non-discriminatory terms. Moreover, AU has been appointed as the central oil stockholding entity (OCSIT);\(^{16}\)
- **c** the Energy Research Body (RSE), carries out publicly funded national and international programmes in the fields of electrical power, energy and the environment.

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9 See Article 2.20 of Law No. 481 of 14 November 1995 and Article 45 of Legislative Decree No. 93 of 1 June 2011. For a recent analysis of the nature and limits of ARERA’s regulatory powers, see E Quadri, I provvedimenti tipici dell’ARERA: la loro classificazione e i riflessi sull’ambito del sindacato giurisdizionale, published on 11 March 2019 on www.giustizia-amministrativa.it.


11 E Picozza, S Sambri, op. cit., p. 155. The Inter-Ministerial Prices Committee established the Equalisation Fund in 1961 with the mandate to compensate the losses due to the unification of electricity prices. The current structure of the CSEA is the result of the reform enacted by Law No. 208 of 28 December 2015.

12 See, for example, ARERA Resolution No. 921/2017/R/ee of 28 December 2017, as last amended by Resolution No. 644/2018/R/ee of 11 December 2018, concerning the contributions in favour of energy-hungry enterprises.

13 E Picozza, S Sambri, op. cit., p. 165. GSE was founded pursuant to Legislative Decree No. 79 of 16 March 1999. The Ministry of Economy and Finance owns 100 per cent of its share capital, but the Ministry of Economic Development sets down the strategic and operational guidelines. Originally, its main function was the management of the electricity transmission grid. However, in 2005, this function was transferred to Terna S.p.A., while GSE specialised in renewable energy and public incentives.


15 E Picozza, S Sambri, op. cit., p. 176.

16 See Legislative Decree No. 249 of 31 December 2012 and EU Directive 2009/119/CE.
ii Regulated activities

With regards to the electricity market, the liberalisation process started with the approval of Legislative Decree No. 79 of 16 March 1999 (also known as the Bersani Decree), which established that the production, importation, exportation, purchase and sale of electricity are free-market activities.

The transmission and dispatching of electricity, however, remain under state control and are managed through a concession scheme by the National Transmission Grid Manager (Terna S.p.A.). More specifically, Terna runs long-distance and high voltage transmission, while different Distribution Service Operators (DSOs) are responsible for providing and operating low, medium and high voltage networks for regional distribution of electricity as well as for supply of lower-level distribution systems and directly connected customers.17

As for the gas market, Legislative Decree No. 164 of 23 May 2000 (Letta Decree) stated that the activities of importation, exportation, transportation, dispatching, distribution and sale of natural gas, in whatever form and for whatever use, are free.

Subsequently, Law No. 239 of 23 August 2004 (Marzano Act) provided a common regulatory framework, by clarifying that:

- the production, import, export, dispatch, purchase, transformation and sale of energy is free, albeit in accordance with public service obligations;
- both the transportation and dispatch of natural gas and the management of energy supply networks are activities of public interest and therefore are subject to public service obligations; and
- the distribution of electricity and natural gas, the exploration and production of hydrocarbons and the transmission and dispatch of electricity are all subject to concession by the competent authorities.

The development and construction of new facilities and infrastructures (e.g., transmission lines, power plants and gas storage facilities) require prior authorisation under state and regional legislation, in order to ensure compliance with, inter alia, health and safety standards, environmental protection and existing infrastructure.18

iii Ownership and market access restrictions

The Italian energy market is open to foreign investors as there are no discriminatory ownership or market access restrictions.

This does not exclude that, in relation to mergers and acquisitions, national and European antitrust authorities may impose certain limitations or prescriptions in order to enforce competition rules.

With respect to strategic assets, see Section II.iv.

iv Transfers of control and assignments

By Decree Law No. 21 of 15 March 2012 (converted into Law No. 56 of 11 May 2012), the Italian government provided market operators with an organic set of rules regarding state intervention in the context of corporate transactions involving strategic sectors such as energy, transports and communications.

17 See Legislative Decree No. 79 of 16 March 1999.
18 See Legislative Decree No. 164 of 23 May 2000.
Specifically, the Decree establishes that the government must be notified within 10 days of any corporate decision, act or measure concerning a strategic asset (i.e., any changes in the ownership, control or in the company objects; acquisitions, dissolutions, mergers and demergers; and the transfer abroad of the registered office). 19

Within 15 days of the notification, the government may exercise what are known as its ‘golden powers’ in the form of vetoes or conditions, but only if the notified operation poses an exceptional threat to national interests.

Should no special power be exercised within the said term, the operation is to be deemed tacitly authorised.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The unbundling obligations model (OU model) on vertically integrated energy operators represents one of the main regulatory instruments adopted by the EU in order to impose impartiality and neutrality in the management and development of the energy infrastructure network, which is a natural monopoly market system (the ‘essential facility’). 20

With regard to the electricity transmission grid, Legislative Decree No. 93 of 1 June 2011 imposed the independence of the transmission system operator (Terna S.p.A.) from businesses operating in the generation, distribution and sale of energy. 21

The OU model was also implemented in the natural gas market, with regards to the role of the network operator, Snam Rete Gas S.p.A. 22

In 2015, ARERA codified the detailed obligations of vertically integrated companies in terms of unbundling (ownership separation) and debranding (brand and communication separation) between distribution and sale or other lines of business. 23

The electricity and gas distribution is regulated as a territorial monopoly, meaning that a public tender for the concession of the distribution service to a single operator (DSO) in each minimum geographical area must be held.

However, in the electricity sector, such tenders shall start no earlier than 2030, because the concessions issued on 31 March 2001 shall remain in force until 31 December 2030. 24

In the gas sector, the above-mentioned Letta Decree and the subsequent Law-Decree No. 159 of 1 October 2007 entrusted the local authorities with the duty to award the distribution service through public tenders for a maximum of 12 years, but the opening up of the market to competition is far from concluded. In fact, in most geographical areas, the public tenders have not been launched or have been delayed. As of October 2018, Milan

19 Pursuant to Article 1 of Presidential Decree No. 85 of 25 March 2014, the national electricity and gas network infrastructure is considered of strategic importance for the purposes of the Golden Power rules. Moreover, Law No. 172 of 4 December 2017 delegated to the Government the task of identifying further high-tech assets that should undergo the Golden Power screening. However, the relevant regulations have not been adopted yet.

20 EU Directives 2009/72/EC and 2009/73/EC.

21 On 5 April 2013 Terna S.p.A. was declared compliant with the OU model (see ARERA Resolution No. 142/2013/R/eel).

22 On 14 November 2013 Snam Rete Gas S.p.A. was declared compliant with the OU model (see ARERA Resolution 515/2013/R/Gas).

23 See ARERA Resolution 296/2015/R/COM, as last amended by Resolution 15/2018/R/COM.

24 See Article 9 of Legislative Decree No. 79 of 16 March 1999.
was the only area where such tenders have concluded (with the confirmation of the outgoing operator Unareti S.p.A., a subsidiary of the A2A Group, in which the municipality of Milan holds a substantial equity stake). The procedure is currently under judicial review by the Administrative Court of Milan (Case No. 2304/2018).

ii Transmission/transportation and distribution access

All network operators must ensure that any interested service provider has access to the transmission and distribution networks of gas and electricity. At the same time, the third-party access (TPA) must not affect the continuity and safety of the transmission and distribution service.

With reference to the electricity sector, ARERA’s Consolidated Text of Active Connections sets forth the detailed technical and economic conditions for TPA to transmission and distribution networks.25

Moreover, with prior approval by ARERA and MiSE, TSO Terna S.p.A. has enacted its own Grid Code, which contains non-discriminatory TPA rules with specific reference to the national transmission grid.26

Similar regulatory instruments have been implemented in the gas sector through the Network Type Code (as a reference model applicable to all network operators)27 and the Snam Network Code.28

In the event that a dispute arises with a network operator, service providers may avail themselves of a special ADR proceeding before ARERA.29

Finally, it is also noteworthy that the Ministry of Economic Development (upon consultation with ARERA) may exempt those network operators that invest in the development of new interconnections with EU countries or in the expansion of the transport capacity of pre-existing infrastructure from TPA obligations.30

iii Rates

In accordance with a pro-competition regulatory strategy, ARERA predetermines the rates for transmission/transportation and distribution of electricity and gas through a pricing mechanism based on a balance between the several interests at stake (network maintenance, promotion of investments, safety and efficiency of the network, environmental protection and accessible costs for the customers).31

26 See the Decree of the President of the Council of Ministers dated 11 May 2004 and ARERA Resolution No. 79/2005, as last amended by Resolution 83/2019/R/eel.
28 See Article 24.5 of Legislative Decree No. 164 of 23 May 2000 and ARERA Resolution No. 75/2003.
30 See Article 1.17 of Law No. 239 of 23 August 2004, as amended by Article 33.1 of Legislative Decree No. 93 of 1 June 2011.
31 See Article 2.12 of Law No. 481 of 14 November 1995.
With respect to the electricity market, on 23 December 2015 ARERA adopted the Pricing Regulation on electricity transmission, distribution and metering for the period 2016–2023.\(^{32}\)

The tariffs of remuneration of transmission and distribution networks are supposed to safeguard the fair allocation of the efficiencies achieved by the service among businesses and consumers, in accordance with the price cap method.\(^{33}\) In fact, price-cap regulations set a cap on the price that the utility provider can charge. The cap is set according to several economic factors, such as the price cap index, expected efficiency savings and inflation. The presence of a price-cap regulation can compel utility companies to find ways to reduce their costs in order to improve their profit margins.

As regards the gas market, in August 2017 ARERA set down the Pricing Criteria for the rates of transportation and dispatching of natural gas for the period 2018–2019.\(^{34}\)

A separate tariff regulation for distribution and metering was issued in 2013 for the period 2014–2019: in particular, ARERA predetermines both the tariffs (which should cover all the distribution costs) and the permitted revenue level, subject to balancing mechanisms with the Equalisation Fund whenever the actual revenues differ from the latter.\(^{35}\)

### iv Security and technology restrictions

As mentioned above, energy infrastructure is of strategic importance for the economy and is therefore subject to particular safety measures.\(^{36}\)

A fundamental element for the security of electrical infrastructure is the continuity of the service, as measured by the ‘energy not supplied’ and other indicators.\(^{37}\) For this reason, ARERA demands that distribution operators disclose the relevant data on service continuity every year.\(^{38}\)

The regulation of the quality of the natural gas transportation service in terms of security, continuity and commercial quality in the period 2018–2019 is governed by Resolution No. 43/2018/R/gas of 1 February 2018.

Furthermore, Part I of the Consolidated Text on the regulation of quality and tariffs of gas distribution and metering services 2014–2019 regulates certain activities relevant to

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33 See Article 2.18 of Law No. 481 of 14 November 1995 and Article 1 quinquies, para. 7, of Law-Decree No. 239 of 29 August 2003, converted into Law No. 290 of 27 October 2003.


36 For instance, Terna S.p.A. updates the Grid Security Plan on a yearly basis.


38 See Article 2.20 of Law No. 481 of 14 November 1995 and ARERA Resolution No. 646/2015/R/eel of 22 December 2015.
the safety of the gas distribution service.\textsuperscript{39} Said regulation is intended to minimise the risk of explosions and fires caused by the gas distributed, and therefore its ultimate goal is to protect people and property from damages due to accidents caused by gas.

Additional protective measures must be taken in respect of European Critical Infrastructure, subject to prior identification by an inter-ministerial committee with the participation – in case of energy assets – of representatives from the Ministry of Economic Development.\textsuperscript{40}

In order to face the new challenges arising from smart grid infrastructure and cyber-attacks, Italy has recently transposed into national law the provisions of the 2016 Network and Information Security (NIS) Directive.\textsuperscript{41}

Consequently, all operators of essential services are bound to: (i) take appropriate and proportionate technical and organisational measures and; (ii) notify, without undue delay, the competent authority (in the energy sector, the Ministry of Economic Development) of incidents having a significant impact on the continuity of the essential services they provide.

In the gas and electricity sectors, all supply, distribution, transmission and storage operators are considered as operators of essential services and are therefore subject to the obligations established by the NIS Directive.

\section*{IV ENERGY MARKETS}

\subsection*{i Development of energy markets}

As previously mentioned, the Energy Markets Manager (GME) runs the Italian Power Exchange (IPEX), a platform dedicated to the wholesale trading of gas, electricity and energy efficiency certificates.

More specifically, GME organises and manages two main venues:

\begin{itemize}
  \item \textit{a} the Forward Electricity Market, where forward electricity contracts with delivery and withdrawal obligations are traded;
  \item \textit{b} the Spot Electricity Market, which consists of:
    \begin{itemize}
      \item the Day-Ahead Market (MGP), an auction market where hourly energy blocks are traded for the next day and participants submit bids by specifying the quantity and the minimum/maximum price at which they are willing to sell/purchase;
      \item the Intra-Day Market (MI), which allows participants to modify the schedules defined in the MGP by submitting additional supply offers or demand bids; and
      \item the Daily Products Market (MPEG), a continuous trading venue for the trading of daily products with the obligation of energy delivery.
    \end{itemize}
\end{itemize}

Moreover, GME manages, on behalf of Terna S.p.A., both the Ancillary Services Market (MSD) through which it collects offers and communicates the results, as well as a platform registering the transactions carried out over the counter. On this platform, the parties that have concluded contracts outside the IPEX register their trade obligations and set forth the relevant electricity input and output plans, committing to perform these contracts.\textsuperscript{42}

\textsuperscript{39} See ARERA Resolution No. 574/2013/R/gas, as last amended by Resolution No. 522/2017/R/gas.
\textsuperscript{40} See Legislative Decree No. 61 of 11 April 2011 and EU Directive No. 2008/114/EC.
\textsuperscript{41} See Legislative Decree No. 65 of 18 May 2018 and EU Directive No. 1148 of 6 July 2016.
\textsuperscript{42} See Article 5 of Legislative Decree No. 79 of 16 March 1999.
Finally, in 2009, GME was entrusted with the organisation and economic management of the natural gas markets on an exclusive basis.\textsuperscript{43}

The main markets in the gas sector are:

\begin{itemize}
  \item \textit{a} the gas trading platform (P-GAS), where the gas quotas of parties subject to the obligations of Article 11 of Law-Decree No. 7/2007 are bid, and where investors participating in virtual gas storage may fulfil their obligation to bid the gas quantities made available by the virtual storage operators associated with them. In order to trade on the P-GAS, operators must be authorised to carry out transactions at the virtual trading point;\textsuperscript{44} and
  \item \textit{b} the wholesale gas market (MGAS), where parties authorised to carry out transactions at the virtual trading point may make forward purchases, also functional in the balancing of the gas system, and spot purchases and sales of volumes of natural gas. In the MGAS, GME plays the role of central counterparty to the transactions concluded by market participants.\textsuperscript{45}
\end{itemize}

The old balancing platform (PB-GAS) is now inactive.\textsuperscript{46}

\section*{ii Energy market rules and regulation}

The Bersani Decree has entrusted GME with the responsibility of organising and supervising transactions in the electricity market under the criteria of neutrality, transparency, objectivity and competition between producers.\textsuperscript{47}

On 19 December 2003, the Ministry of Economic Development approved the Integrated Text of the Electricity Market Rules.\textsuperscript{48} It falls within the competence of GME to draft amendments, which are subject to approval by MiSE and ARERA.\textsuperscript{49}

On 6 March 2013, the Ministry approved the Integrated Text of the Gas Market Rules.\textsuperscript{50} As in the case of the electricity market, one of the main tasks of GME is to propose the necessary amendments to MiSE and ARERA so that the regulatory framework is up to date with the most recent market developments.\textsuperscript{51}

These regulations include the criteria and procedures for the admission of new participants, the trading and settlement rules, as well as disciplinary procedures in case of misconduct by the market operators.\textsuperscript{52}

\textsuperscript{43} See Article 30 of Law No. 99 of 23 July 2009.
\textsuperscript{44} For more information, visit www.mercatoelettrico.org/It/Default.aspx.
\textsuperscript{45} For more information, visit www.mercatoelettrico.org/It/Default.aspx.
\textsuperscript{46} See ARERA Resolution No. 312/2016/R/gas. For more information, visit www.mercatoelettrico.org/It/Default.aspx.
\textsuperscript{47} See Article 5.1 of Legislative Decree No. 79 of 16 March 1999.
\textsuperscript{48} See Ministerial Decree No. 12783 of 19 December 2003, as last amended by Ministerial Decree dated 21 September 2016.
\textsuperscript{49} See Article 3 of the Integrated Text of the Electricity Market Rules.
\textsuperscript{50} See Ministerial Decree dated 6 March 2013, as last amended by GME on 8 February 2019 following ARERA Resolution No. 612/2018/R/gas.
\textsuperscript{51} See Article 3 of the Integrated Text of Gas Market Rules.
\textsuperscript{52} See the Decrees of the Ministry of the Economic Development approved on 19 December 2003 and 6 March 2013 as last amended by, respectively, the Ministerial Decrees dated 21 September 2016 and 18 December 2017.
Within the boundaries of said regulatory framework, GME is also entitled to issue specific technical provisions (DTF) that help operators understand the rules established in the aforementioned integrated texts.53

iii  Contracts for sale of energy

At wholesale level, contracts for the sale of electricity and gas can be signed either within the organised markets managed by GME or over the counter. In the latter case, the parties are free to agree the price for the supply, as well as the injection and withdrawal profiles, but the transactions must be registered onto the OTC Registration Platform (PCE), where they will be checked for consistency with the transmission constraints on the National Transmission Grid.54

At retail level, since 2003 (gas)55 and 2007 (electricity),56 consumers are free to choose the gas or electricity provider that applies the best economic and technical conditions, under the regulatory supervision of ARERA.

However, until 1 July 2020, consumers can choose to purchase electricity and gas under the tariffs laid down by ARERA.57

iv  Market developments

The retail market in Italy is divided into three categories, and the first two are subject to regulated prices:

a  an enhanced protection service for domestic customers and small companies connected to the low voltage grid that have not signed a contract for purchases in the free market. Operation of this service is reserved to the single buyer;

b  a safeguarded service for all customers not eligible for the enhanced protection service and that have no contract for purchases on the free market. This service is delivered by providers selected by the single buyer through a competitive tender; and

c  the free market, namely the remainder of the retail market.

However, starting from 1 July 2020, the free market will be the only option available for energy consumers, meaning that ARERA will no longer regulate prices.58

The reform is based on the assumption that free competition between energy suppliers will result in lower prices for consumers. For the reform to succeed, the 2017 Competition Law has established:

a  the creation of a web portal for the collection and publication of suppliers’ offers;59

b  the obligation for sellers to formulate a variable-price and a fixed-price offer;

55 See Legislative Decree No. 164 of 23 May 2000.
56 See Article 1, 30 of Law No. 239 of 23 August 2004.
58 See Article 1, paragraphs 59 and 60, of Law No. 124 of 4 August 2017.
59 See ARERA Resolution No. 51/2018/R/com of 1 February 2018. For more information, visit https://www.prezzoenergia.it/portaleOfferte/.
the adoption of ARERA guidelines aimed at facilitating the aggregation of small consumers and the creation of purchasing groups;\textsuperscript{60} and

\textit{d} the obligation for suppliers to provide adequate information to consumers and a high level of disclosure.\textsuperscript{61}

Much has been done, but the transition towards the free market is still in progress as the regulators are struggling to take all the necessary countermeasures to protect the consumers from any negative impact of price deregulation.

V

RENEWABLE ENERGY AND CONSERVATION

\textbf{i} Development of renewable energy

In accordance with EU legislation, Italian law considers renewable energy as the power generated by non-fossil sources, namely wind, solar, aerothermal, geothermal, hydrothermal and ocean energy, hydropower, biomass, landfill gas, sewage treatment, plant gas and biogases.\textsuperscript{62}

The authorisation, certification and licensing procedures that are applied to plants and associated transmission and distribution network infrastructures for the production of electricity, heating or cooling from renewable energy sources, and to the process of transformation of biomass into biofuels or other energy products, are simplified and proportionate.\textsuperscript{63}

Depending on the technical specifications of the power plant, the law provides for three different administrative regimes: the single authorisation, issued by the region pursuant to a single meeting of the authorities involved; the simplified authorisation procedure, managed by the competent municipality; and the free construction regime, subject to a simple notification to the municipality.\textsuperscript{64}

These special procedures aim to promote power production from renewable energy sources by providing for shorter processing times and more streamlined proceedings compared to ordinary ones.

In the context of the most recent administrative reforms, Italian lawmakers have paid more attention to the simplification of authorisation procedures for renewable energy plants. For instance, the installation of photovoltaic panels on buildings was recently exempted from any kind of prior bureaucratic procedure.\textsuperscript{65}

\textsuperscript{60} See ARERA Resolution No. 59/2019/R/com of 19 February 2019.


\textsuperscript{63} See Article 4.1 of Legislative Decree No. 28/2011 and Article 13.1 of EU Directive No. 2009/28/EC.

\textsuperscript{64} See Article 2 of Legislative Decree No. 28/2011.

\textsuperscript{65} See Article 3 of Legislative Decree No. 222 of 25 November 2016 and the Decree of the Minister of Infrastructure and Transports dated 2 March 2018.
For final customers to know the amount of renewable energy in the fuel mix of a given energy supplier, Italy has introduced the guarantees of origin (GO), which are tradable certificates issued by GSE that may be sold or bought in the GO market or bilaterally. Each supplier must have an amount of GOs equal to the energy sold.

A significant development in the promotion of renewable energy is represented by the recent ministerial decree that finally extended the economic incentives to the production of biomethane for transport: a key role is played by GSE, which collects the product and then issues the incentives.

Lastly, it should be noted that an organic reform of the incentives related to solar, wind and biomass power sources (the FER 1 Decree) is being formulated: according to the general lines of the reform, access to the new incentives will be granted pursuant to public tenders based on economic and environmental criteria. A separate decree (the FER 2 Decree) for geothermal sources has been announced.

ii Energy efficiency and conservation

According to a June 2018 report drafted by the Polytechnic of Milan, the energy efficiency sector appears to be a flourishing segment of the energy market in Italy, with €6.7 billion in investments registered in 2017, in line with a positive trend dating back to 2014, and an estimated growth of between €37 and €27 billion in the period 2018–2021.

In particular, Italy has so far invested about 130 million euros for the improvement of energy efficiency of public buildings. This is the result of framework agreements awarded by CONSIP; tenders launched by the regions; and specific project financing deals between public administrations and private undertakings.

Within the framework provided by the European Union, Italy has established its own energy efficiency strategy, which is based – among other factors – upon: the energy efficiency certificates, which are issued by the GME under an authorisation granted by the GSE and give evidence of energy savings that electricity and gas distributors with over 50,000 customers are required to achieve. They may be sold or otherwise utilized.

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66 See Article 34 of Legislative Decree No. 28/2011 and Article 15 of EU Directive No. 2009/28/EC.
67 See Article 3 of ARERA Resolution No. ARG/elt/104/11 of 28 July 2011, as supplemented by Resolutions No. 118/2016/R/efr and No. 96/2018/R/efr.
68 See the Decree issued on 2 March 2018 by the Ministry of Economic Development in agreement with the Ministry of Environment and the Ministry of Agriculture.
72 ibid., p. 315.
73 ibid., p. 185.
74 ibid., p. 188. CONSIP is the central contracting authority that awards framework agreements for the purchase of goods and services by public administrations.
75 ibid., p. 194.
76 ibid., p. 200.
bought in the energy efficiency certificates market or bilaterally. Bilateral transactions should then be registered on the Platform for Registration of Energy Efficiency Bilaterals;\textsuperscript{78}

\textit{b} the Thermal Energy Account, an economic incentive system, which can be accessed by both public administrations and private businesses and households that implement energy efficiency improvement actions in buildings and technical installations;\textsuperscript{79}

\textit{c} the National Fund for Energy Efficiency, dedicated to the financing of energy-saving measures introduced by public administrations and private undertakings,\textsuperscript{80} including district heating and cooling networks;\textsuperscript{81}

d tax reliefs on renovations to improve the energy efficiency of existing buildings,\textsuperscript{82} such as the replacement of windows and doors and the installation of biomass boilers, solar panels and micro-cogenerators;\textsuperscript{83} and

e specific construction regulations aimed at ensuring that new buildings comply with the most advanced energetic performance standards. For instance, pursuant to Article 11 and Annex III of Legislative Decree No. 28/2011 (the Romani Decree), the projects of new buildings or huge renovation works must ensure that most of the power consumption is covered by renewable energy sources. Otherwise, the competent municipality shall reject the building application. Moreover, pursuant to Article 15 of Legislative Decree No. 257 of 16 December 2016, every Municipality is expected to amend the local building regulations by establishing that new buildings must be provided with electric-vehicle charging stations.

\textsuperscript{78} See the Decrees issued by the Minister of Productive Activities (now Economic Development), jointly with the Minister of Environment, on 20 July 2004, as subsequently amended and supplemented by the Ministerial Decrees of 21 December 2007, of 28 December 2012, of 11 January 2017 and of 10 May 2018.

\textsuperscript{79} See the Decree issued on 16 February 2016 by the Ministry of Economic Development in agreement with the Ministry of Environment and the Ministry of Agriculture. For more information, visit https://www.gse.it/servizi-per-te/efficienza-energetica/conto-termico.

\textsuperscript{80} See Article 15 of Legislative Decree No. 102/2014 and Ministerial Decree dated 22 December 2017. With specific reference to state buildings, the Joint Decree issued on 16 September 2016 by the Ministers of Economic Development, Environment, Infrastructure and Finance provided the rules and the funds for yearly energy saving programmes to be executed from 2014 to 2020: this is the PREPAC plan.

\textsuperscript{81} As recognised by EU Directive No. 27/2012, high-efficiency cogeneration and district heating and cooling have significant potential for saving primary energy, because of the combined production of heat and electricity and the replacement of individual boilers with simple heat exchangers. With regard to this subject matter, Riccardo Villata recently delivered a speech on the legal nature of district heating at the conference ‘La regolazione del teleriscaldamento’, held by AIDEN (Associazione Italiana di Diritto dell’Energia) in Milan on 5 March 2019.

\textsuperscript{82} See Law No. 205 of 27 December 2017, as supplemented by Law No. 145 of 30 December 2018.

The National Agency for Energy Efficiency provides assistance for the realisation of new projects and runs information campaigns on the importance of energy saving, while several Energy Service Companies (ESCOs) compete on the free market by offering their energy efficiency improvement measures to private and public entities.

The law defines ESCOs as natural or legal persons that deliver energy services or other energy efficiency measures in a user’s facility or premises, and accept some degree of financial risk in so doing. The payment for the services delivered is based (either wholly or in part) on the achievement of energy efficiency improvements and on the meeting of the other agreed performance criteria. According to the already mentioned report published by the Milan Polytechnic, in 2017 the number of ESCOs increased by 30 per cent, with almost 10,000 employees working in the sector. Moreover, the same report highlights the recent tendency of large utility operators to acquire or incorporate major ESCOs in order to achieve a higher degree of vertical integration.

Therefore, it can be argued that the Italian regulatory system displays a wide array of opportunities and instruments designed to promote energy saving, and more of them are expected to come into force following the transposition of the 2018 Energy Efficiency Directive. In fact, by 10 March 2020, each Member State shall establish a long-term renovation strategy to support the renovation of the national stock of residential and non-residential buildings, both public and private, into a highly energy efficient and decarbonised building stock by 2050, facilitating the cost-effective transformation of existing buildings into nearly zero-energy buildings.

iii Technological developments

The implementation of ICT technologies and artificial intelligence within the energy supply chain continues to play an important role in the Italian market. Smart grids are energy networks that can automatically monitor energy flows and adjust to changes in energy supply and demand accordingly. When coupled with smart metering systems, smart grids reach consumers and suppliers by providing information on real-time consumption. With smart meters, consumers can adapt – in time and volume – their energy usage to different energy prices throughout the day, saving money on their energy bills by consuming more energy in lower price periods.

84 See Article 4 of Legislative Decree No. 115/2008 and Article 4 of Law No. 221 of 28 December 2015.
85 With regards to the relationship between ESCOs and Public-Private Partnership Agreements, Riccardo Villata gave the speech ‘Il Partenariato Pubblico-Privato nel settore dell’energia’ at the conference ‘Il Codice dei contratti pubblici e gli appalti nei Settori speciali dell’energia’, held by AIDEN (Associazione Italiana di Diritto dell’Energia) in Milan on 22 May 2017.
86 See Article 2.1.i) of Legislative Decree No. 115/2008.
88 ibid., p. 66.
Following the smart-grid pilot projects carried out by several operators in Italy since 2011,\textsuperscript{91} the Ministry of Economic Development has established a state-aid programme dedicated to investments for the construction of intelligent electricity distribution networks.\textsuperscript{92} The programme is valid until 31 December 2020.\textsuperscript{93}

The relevant ministerial decree provides a common legal and economic framework for public administrations to launch calls for tenders, in order to promote the upgrading and optimisation of the electrical network in specific areas of the country.\textsuperscript{94}

As for second generation smart metering (i.e., the remote reading and control of power consumption), in the electricity sector ARERA has issued detailed rules on the recognition of costs for low-voltage electricity metering,\textsuperscript{95} while in the gas sector it has laid down the mandatory commissioning amounts and requirements of smart gas meters.\textsuperscript{96} The purpose of these regulations is to both encourage and compel distribution undertakings to upgrade their assets to meet the ongoing technological developments.

VI THE YEAR IN REVIEW

The 2019 Budget Law (Law No. 145 of 30 December 2018) introduced several measures related to the above-mentioned aspects of the energy market, namely:

\begin{itemize}
  \item[a] the extension of the tax deductions for renovations aimed at improving the energy performance of buildings until 31 December 2019;
  \item[b] the extension of the duration of old incentives\textsuperscript{97} for biogas plants with a power of less than 300kW, pending the adoption of new incentives under the aforementioned ‘FER 2’ Decree, on the condition that the power is used for self-consumption in the production process of agricultural undertakings;
  \item[c] the increase of the National Energy Efficiency Fund by €25 million in 2019 and €40 million for each year from 2020 to 2022, in order to accelerate the energetic requalification of state properties;
  \item[d] the renegotiation of the economic conditions of the bilateral agreements signed by local authorities with the owners of renewable sources plants prior to 3 October 2010, in accordance with the national guidelines for the authorisation of such plants;\textsuperscript{98} and
  \item[e] further tax incentives for the construction of electric-vehicle charging stations.
\end{itemize}

\textsuperscript{91} See ARERA Resolution No. ARG/elt 39/10 and the consultation paper No. 255/2015/R/eel.
\textsuperscript{92} See Ministerial Decree dated 19 October 2016.
\textsuperscript{93} See Article 3 of Ministerial Decree dated 19 October 2016.
\textsuperscript{95} See ARERA Resolutions No. 646/2016/R/eel of 10 November 2016 and No. 222/2017/R/eel of 6 April 2017.
\textsuperscript{97} See the Decree of the Ministry of Economic Development dated 23 June 2016.
\textsuperscript{98} See the Decree of the Ministry of Economic Development dated 10 September 2010.
The 2019 Budget Law thus confirmed the role of energy efficiency and requalification as key drivers for economic growth within the Italian energy agenda.

Shortly after, the parliamentary ratification (with amendments) of the Simplifications Decree No. 135/2018 brought two significant changes to the regulatory framework of energy sources:

- a temporary moratorium on both the issuance of new permits for hydrocarbon exploration and the effectiveness of pre-existing ones (together with a recalculation of the concession charges effective from 1 June 2019), while the Ministries of Economic Development and Environment prepare an ad hoc plan for the identification of suitable exploration areas;
- the principles according to which the regions should set up tender procedures for the awarding of the large water concessions that have expired or are going to expire in the next few years.

VII CONCLUSIONS AND OUTLOOK

To conclude, it is worth recalling the main contents of the 2017 National Energy Strategy, since it lays down the steps to be taken by 2030, in accordance with the long-term scenario drawn up in the EU Energy Roadmap 2050 for a reduction of greenhouse gas emissions by at least 80 per cent from the levels of 1990.

The Strategy aims to bring the national energy system to a higher degree of:

- competitiveness, by aligning Italian energy prices with European ones to the benefit of both companies and consumers, opening up new markets to innovative companies, creating new employment opportunities and fostering research and development;
- sustainability, by accelerating the decommissioning of coal-fired thermal power plants by 2025, based on a detailed plan of infrastructural actions in line with the long-term targets of the Paris Agreement on Climate Change (2015), and by furthering energy-efficiency projects that maximise sustainability benefits; and
- security, by improving the security of energy supply, while ensuring its flexibility and strengthening Italy’s energetic independence.
The parliamentary elections of March 2018 and the subsequent change of government do not appear to have affected Italy’s overall strategy as far as energy policy is concerned, since the targets set out in the draft National Energy and Climate Plan dated 31 December 2018 are essentially in line with the above-mentioned objectives.\textsuperscript{106}

According to the draft NECP, by 2030 the share of energy deriving from renewable sources should amount to 30 per cent of the gross consumption and the greenhouse gas emissions from non-ETS sectors should drop by 33 per cent.

In the course of 2019, the draft plan will be assessed by the European Commission and will also undergo a strategic environmental assessment at national level.\textsuperscript{107}

\textsuperscript{106} Pursuant to Article 9 of EU Regulation No. 1999/2018 dated 11 December 2018, ‘By 31 December 2018, and subsequently by 1 January 2028 and every ten years thereafter, each Member State shall prepare and submit to the Commission a draft of the integrated national energy and climate plan.’

\textsuperscript{107} Pursuant to Article 2 of EU Regulation No. 1999/2018, each Member State shall notify the Commission with the final version of the NECP by 31 December 2019.
I OVERVIEW

Japan is a country with limited natural energy resources and as such, energy legislation in Japan can essentially be divided into legislation concerning electricity and that concerning gas.

Given the high level of public interest attached to the provision of electric utilities, certain market entry regulations have long been in place. However, because of the Great East Japan earthquake and the subsequent accident at the Fukushima Daiichi nuclear power plant in 2011, government energy policy is currently in the midst of vast and rapid structural change. As of 31 March 2019, all but nine nuclear power plants are currently under suspension in Japan and over recent years other measures to secure alternative resources (including increasing the supply of renewable energy sources and traditional thermal power), conserve existing energy supplies and increase local energy production have been discussed concurrently with a review of the current industry regulations. As a result, the current legislation is in a transitional phase. There are three headline changes affecting the regulation of electricity markets. Firstly, under the Electricity System Reform programme, entry into the electricity retail business was fully liberalised as of 1 April 2016. In preparation for this, a new regulatory authority for monitoring the new liberalised market was established in 2015. Secondly, the legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers will be implemented on 1 April 2020. In addition to these two changes, feed-in tariffs (FITs) were introduced in 2012 and the renewable energy market has been rapidly expanded since then. In response to rapid expansion of the renewables market, the FIT system has been continuously revised to address several problems.

The gas industry in Japan can be divided into the following two major enterprises: the town gas industry, which is the primary source of natural gas to consumer residences through piping; and the liquefied petroleum gas (LPG) industry, which provides LPG via cylinders to consumers in areas where piped gas is not yet available. Significant reform liberalising the town gas retail business was implemented on 1 April 2017. As a result, subcategories of the town gas-related business was reorganised and entry into the retail gas business has been relaxed (i.e., only registration is required). Entry into the LPG industry requires registration with the relevant authority, and the prices for the provision of LPG may be freely set by the provider.

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1 Reiji Takahashi, Norifumi Takeuchi and Wataru Higuchi are partners, Kunihiro Yokoi is a special counsel, and Keisuke Hayashi and Kei Takada are associates at Anderson Mōri & Tomotsune.
II REGULATION

i The regulators

The energy industry in Japan, which encompasses electric power, gas and other energy resources, is regulated by the Ministry of Economy, Trade and Industry (METI) or, more specifically, the Ministry's Agency for Natural Resources and Energy and the Electricity and Gas Market Surveillance Commission. The Ministry of Economy, Trade and Industries Establishment Act grants the Ministry jurisdiction over various matters including comprehensive policies in relation to energy and mineral resources and the securing of the stable and efficient provision of gas, electric power and heating to Japan. In addition to these matters, comprehensive policies in relation to energy and mineral resources and the securing of the stable supply of energy are handled by the Ministry’s Agency for Natural Resources and Energy, and the monitoring of the liberalised electricity markets, as well as compliance with a code of conduct for network sectors, is handled by the recently established Electricity and Gas Market Surveillance Commission.

The Organization for Cross-regional Coordination of Transmission Operators (OCCTO) is not a governmental organisation but is an independent organisation constituted by all of the electricity business entities pursuant to the Electricity Business Act (EBA). The OCCTO’s remit is to monitor the electricity supply–demand balance and frequency, and order electricity business entities to supply electricity to other electricity business entities. The OCCTO has the power to instruct or recommend electricity business entities to ensure stable electricity supply subject to Article 28-40, Item 6 of the EBA.

Other governmental agencies regulate certain aspects of the energy industry in Japan, including the Ministry of Environment, the Nuclear Regulation Authority and relevant local governments.

Main sources of law and regulation

The EBA is the main source of legislation regulating businesses involved in the generation, transmission and distribution, and sale of electric power. In addition to this, the Electricity Business Act Enforcement Orders and the Ordinance for Enforcement of the Electricity Business Act further provide detailed regulations for the enforcement and governance of the system provided under the EBA. A number of relevant orders and ordinances ruling the generation, transmission and sale of electricity have also been enacted.

As for nuclear power, regulation is provided in the Atomic Energy Fundamental Act, the Act on Compensation for Nuclear Damage and other specialised legislation.

The Gas Business Act (GBA) is the primary source of legislation regulating businesses involving town gas. In addition to this, the Gas Business Act Enforcement Orders and the Ordinance for Enforcement of the Gas Business Act further provide detailed regulations for the enforcement and government of the system provided under the GBA.

The primary source of legislation regulating businesses involving LPG is the Act Concerning the Securing of Safety and the Optimisation of Transaction of Liquefied Petroleum Gas (the LP Gas Act). In addition to this, the LP Gas Act Enforcement Orders and the Ordinance for Enforcement of the LP Gas Act further provide detailed regulations for the enforcement and government of the system provided under the LP Gas Act.
Regulated activities

Electricity

After the Fukushima incident in 2011, the Japanese government decided to undertake significant reform of the energy regulation system. The regulations for electricity businesses are also undergoing substantial changes at the moment. Prior to the new EBA (which came into effect on 1 April 2016), licences for electricity businesses were required when the intended activities fell within one of five categories, and only 10 prominent regional companies (which used to be categorised as general electricity utilities) were allowed to supply electricity to general consumers and businesses (low-voltage electricity) in their respective markets. However, the amendment to the EBA to liberalise the entire retail electricity market has streamlined regulated electricity business into three simple categories (i.e., electricity retail businesses, generation businesses and transmission and distribution businesses) to adjust to the liberalised retail market and promote a level playing field for competition between the general electricity utilities and other electricity business entities.

Electricity retail business

A company running an electricity retail business (the sale of electricity to general and large-scale consumers and businesses) is required to be registered by the METI. For a company to be registered as a retail company, it is first required to become a member of the OCCTO. Then an application document must be filed to the METI. The METI and the Electricity and Gas Market Surveillance Commission will then examine the application. An application for the register will be accepted unless the business entity’s activities are found to fall under certain negative requirements, including a lack of ability to procure electricity to respond to the maximum demand of its customers and being unable to properly operate an electricity retail business. In anticipation of the market liberalisation, many retail entities have entered this new market with various types of electricity price plans. As of 11 April 2019, 595 entities are registered as retail companies.

Electricity generation business

Companies that generate and supply electricity in excess of 10,000kW to retail companies are required to file with the METI to commence their generation business. They are also required to apply for membership of the OCCTO before filing. Under the old regulation structure of the EBA, independent power producers did not need approval or to file for the commencement of their generation business (provided they filed the price and met the other required terms of the supply of electricity), but under the new EBA, generation business entities are required to file their generation business and are also subject to certain obligations. For example, generation companies are required to submit a plan stating the amount of electricity generation that can be produced by a unit of the facilities they possess. Additionally, by a standard contract with general transmission and distribution companies, generation business entities are required to report their estimation of supply for the next 30 minutes.

Electricity transmission and distribution business

The electricity wheeling service industry is classified into three subcategories: general transmission and distribution, transmission and specific transmission and distribution by the
amended EBA; and each is covered by a different regulatory scheme. Entry to this area has not been liberalised even following the amendment of the EBA because these businesses are responsible for ensuring that all consumers have sufficient access to electricity.

Of the different companies in the three categories, the most prominent are general transmission and distribution companies. General transmission and distribution companies are business entities providing electricity wheeling services through their own transmission lines throughout their service area. Those intending to engage in the general transmission and distribution business are required to obtain approval from the METI in advance. The company must submit a business plan to the METI, which must be satisfied that the plan is feasible. Its facilities also need to be capable of covering the electricity demand. To gain approval, the company must submit a 10-year plan, as do companies in the other two categories above.

A transmission company supplies the electricity to general transmission and distribution companies throughout its own grid. Those intending to engage in the wheeling industry are also required to obtain approval from the METI.

In contrast to these two, specific transmission and distribution companies, which transmit electricity to a specific point, are only required to notify the METI.

**OCCTO**

These three types of electricity business entities are all under an obligation to be a member of the OCCTO to allow the OCCTO monitor and coordinate the whole electricity market. Members of the OCCTO have to provide information about the amount of electricity produced by their facilities, etc. on a continuous basis. The OCCTO can instruct its members to maintain a balance of electricity supply and demand in the market to ensure the stable supply of electricity to consumers.

**Gas**

**Town gas businesses**

In line with the Electricity System Reform, the amendment to the GBA, which came into effect on 1 April 2017, significantly changed the town gas regulation, which is called the Gas System Reform. This amendment implements full liberalisation of entry into the gas retail business, which accounted for 36 per cent of the total town gas supply as of October 2016. The amendment includes reform of the business licence categories that streamline the regulated gas business into three simple categories: gas retail business, generation business and transportation (pipeline) business.

**Town gas retail business**

A company operating a town gas retail business is required to be registered with the METI from 1 April 2017. Before 1 April 2017, approval from the METI was required to do business and removing this requirement is one of the main purposes of the Gas System Reform. Applications for the relevant registration involve the necessary submission of application forms in which statutorily required data, such as gas generating facility and other necessary information, are described. As in the case of an electricity retail business, an application for registration will be accepted unless the applicant's activities are found to fall under certain
negative requirements, including the lack of ability to procure gas to respond to the demand of its customers and being unable to properly operate a gas retail business. In principle, the entire application and registration process will require around one month to complete.

As of 1 April 2019, the number of town gas retail business operators was 68. It should be noted that regional monopolies have been recognised in relation to town gas retail business operators and, accordingly, the percentage of operators for the service areas in large metropolitan areas is understandably high. The share of the largest operator, Tokyo Gas (service area: Kanto region with Tokyo as its main focus), currently accounts for about 38 per cent of the market whereas the combined share of the three major corporations (Tokyo Gas, Osaka Gas and Tohou Gas) providing service areas in large metropolitan areas accounts for about 73 per cent (based on sales volume as of March 2016). The Gas System Reform aims to change the situation by furthering competition in the town gas retail business under the relaxed requirements for entry into the gas retail business.

Town gas generation business
Before 1 April 2017, a town gas generation business was not required to obtain a registration or licence, or file other documents with the METI. However, after 1 April 2017, companies that generate town gas are required to file with the METI.

Town gas transportation business
Under the new regulation, a town gas transportation business is categorised into two subcategories under the new GBA: general gas transportation business and specific gas transportation business. A general gas transportation business is a business that transports gas through its gas pipeline throughout its service areas. In order to operate a general gas transportation business, approval from the METI is required and the business is subject to certain regulations and controls by the METI as explained below. On the other hand, a specific gas transportation business is a business that transports gas through its gas pipeline to a specific point. Only notification to the METI is required in order to operate a specific gas transportation business.

The purpose of this two-tier regulation is to expand the gas pipeline network, which is established on an area basis (especially in urban areas) by separating the gas between the various networks. General gas transportation business operators now have to make their gas pipelines readily available due to strict regulations imposed by the METI, while specific gas transportation business operators may operate their businesses without strict control by the METI.

Sellers of LPG
The LP Gas Act stipulates that necessary registration for the sale of LPG must be obtained from the METI when intending to establish sales offices catering to two or more prefectures and from the prefectural governor when catering to only one prefecture.

Registration involves the necessary submission of application forms in which statutorily required data, such as details of the sales office, gas storage facilities and other necessary information, are described. Applicants will be registered with the corresponding authority (either the METI or the prefectural governor) as long as there are no applicable statutory grounds for denial of the application.

Registrations will require 30 days to process or 15 days if the registration is applied for via the relevant authority’s electronic information processing system.
As of 31 March 2018, the number of business operators that had obtained the necessary registrations and were currently engaged in the sale of LPG was 18,516. Entry barriers to this section of the industry are low and a large number of small and medium-sized businesses have been entering into the LPG industry in which even retail rates are not regulated. While all-electric technology products were widely spread by the electric power companies to replace the use of gas, this figure is approximately one-third of when LPG sales were at their peak (54,000 operators in 1967).

### iii Ownership and market access restrictions

The only existing restrictions on foreign investment in the electric power industry or the gas industry are those imposed by the general laws regulating the entry of foreign investment in Japan stipulated in the Foreign Exchange and Foreign Trade Act. For example, if a foreign investor were to obtain 10 percent or more of the shares of an electric power or gas utility (including both town gas and LP gas), intend to set up a branch for the conduct of electric power or gas business or otherwise engage in any such activities, the Foreign Exchange and Foreign Trade Act requires that the relevant authorities be notified in advance of such activities. Furthermore, in the event of the performance of any such activities requiring advance notification of the relevant authorities, a follow-up report after the performance must also be submitted accordingly. Both prior notification and follow-up reports must be submitted to the Bank of Japan, which in turn will facilitate the submission of the notifications and reports to the Minister of Finance or other relevant minister in charge. The relevant authorities have the power to provide a recommendation or an order to suspend such foreign investment, if it hinders national security, public order or public safety.

### iv Transfers of control and assignments

**Electricity**

The prior approval of the METI is necessary in the event of a transfer of the whole business of a general transmission and distribution company or in the event of a merger or demerger whereby the surviving entity completely absorbs any such business. The criteria for granting such an approval are the same as those for the original grant of approval to operate such businesses. A merger or demerger of other types of electricity business entities obliges them to notify the METI. Notification to the METI is also required upon the handover of any equipment or facilities to retail companies, power suppliers and any types of transmission companies.

**Gas**

The transfer or acquisition of all or part of a general gas transportation business requires authorisation from the METI before it can be effective, as does the merger or demerger of any entity that is a general gas transportation business operator whereby all or part of the business is succeeded by the surviving company. The criteria for the grant of the required authorisation are the same as those for the original grant of approval to operate such businesses. Only post facto notification is required for transfer of the business or merger or demerger of the town gas-related business (i.e., town gas retail business, town gas generation business and specific gas transportation business).
In the case of LPG businesses, however, in the event of any transfer of the business in its entirety or of any merger or demerger whereby the surviving entity completely absorbs the business, the succeeding entity is only required to notify whichever is relevant of the METI or the prefectural governor.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Electric power

*Integrated system for the production and transmission of electric power*

In Japan, following the end of World War II and up until 1995, the production and transmission of electric power, as well as its assorted related retail operations, were run as a single integrated utility by 10 electric power companies, each with a regional monopoly over the 10 main regions of Japan.

However, amid the institutional reform post-1995, Japan realised the liberalisation of its electric power generation and retail sectors. That being said, the electric power transmission sector is still very much dominated by the aforementioned 10 power companies (former general electricity utilities).

Because the electric power distribution grid is public infrastructure, measures have been implemented to prevent general electricity utilities from abusing their dominant market positions and to ensure the transparency of the electric power industry. Specifically, anti-trust measures that have been implemented include, the compulsory notification of electric power transmission details; the requirement of equal treatment of consumers; and the compulsory separation of the electric power transmission division accounts of general electric power business operators from their other divisions.

*Government policy on separation and unbundling of electric power transmission sectors*

As part of the Electricity System Reform, the amendment to the EBA passed in 2015, which aims for the legal unbundling of the transmission sector to ensure the neutrality of all entities engaged in electricity-related business. No electricity company can run an electricity retail business or generation business with a transmission business in the same entity from 1 April 2020, unless otherwise permitted by the METI. That means that the 10 former general electricity utilities, except for Okinawa Electric Power Company, must split those departments to an affiliate or others by that date.

The main obligations and areas of concern for general transmission and distribution companies regarding separation and unbundling are (1) development of a system for information management, (2) rules concerning company names, trademarks and advertising, (3) entrustment and undertaking by such companies, (4) rules concerning transactions among group companies and (5) restriction on holding concurrent positions by directors and employees.

Regarding the development of a system for information management, such companies are required to be physically separated from generation and retail group companies (i.e., being located on different floors with restricted entry) when such companies share the same building, as well as identifying and limiting access to information systems in cases where such systems are shared. In addition, they are required to develop their business status monitoring and surveillance systems.
Companies are generally restricted from using company names and trademarks that are likely to be associated with those of generation and retail group companies, and they are also prohibited from advertising to take advantage of the generation and retail business of other group companies.

Regarding entrustment and undertaking by such companies, such companies are in principle prohibited from entrusting their services in transmission and distribution to their own subsidiary companies. In exceptional cases, they may make such entrustments where the subsidiary companies are not under the control of generation or transmission companies. In addition, general transmission and distribution companies are in principle prohibited from undertaking the services of generation and retail group companies. However, in exceptional cases where the undertaking of such services does not impair the competitive relationships among electricity suppliers, such services may be undertaken.

Transactions among group companies are allowed to the extent that such transactions do not impair the competitive relationships thereof.

Directors of generation and retail business group companies are generally prohibited from acting as directors of general transmission and distribution group companies concurrently. In exceptional cases, a concurrent position may be held where the holding of such a position does not impair the competitive relationships thereof. Additionally, the foregoing restriction also applies to an employee who plays an important role in either of the group companies.

**Obligations undertaken by general transmission and distribution companies**

Because transmission facilities and the business conducted with them are mostly owned by the former 10 general electricity companies, to secure the effective liberalisation of other sectors, these companies are required to provide neutral treatment to retail companies. General transmission and distribution companies are not allowed to refuse to execute a grid connection contract without reasonable grounds. The EBA provides that the electricity supply-demand balance and frequency must always be maintained within a certain threshold. General transmission and distribution companies must also provide final assurances to each consumer to deliver electricity where consumers do not have a contract with any of the retail companies. General transmission and distribution relationship companies are also responsible for the delivery of electricity to consumers on Japan’s remote islands.

**Cybersecurity**

As most activities involved in the electricity business are controlled by information technology, it is urgent for businesses in the sector to establish a reliable cybersecurity system. The Basic Act on Cybersecurity stipulates that Critical Infrastructure Information (CII) operators shall make an effort to assure cybersecurity voluntarily and proactively. Because there is no regulation that clearly stipulates the concrete actions a CII should take with regard to IT protection, a strategy for cybersecurity committee established by the Cabinet has announced that the security criterion for CII operators will be clarified. It is clear that electricity business entities, especially general transmission and distribution companies, fall within the definition of CII operators, and will almost certainly be required to adapt their processes in line with any changes to the security requirements.
Gas

**Terminalling, processing and treatment**

After importation, LNG meant for the town gas industry is converted into gas and sent through pipelines or transported by tanker lorries, and stored in gas storage facilities for supply to consumers. The facilities for processing, transportation and storage are mainly owned by the gas utility business operators, who supply the gas to consumers.

Pipelines that are used for gas transportation and gas holders that are used for storage of gas are regulated by the GBA and the technical standards for gas facilities prescribed by ministerial order. Likewise, tanker lorries are regulated by the High-Pressure Gas Safety Act and the Safety Regulations for General High-Pressure Gas.

The transportation and storage of LPG are regulated by the LP Gas Act and the High-Pressure Gas Safety Act. More particularly, whereas storage and transportation at distribution and wholesale levels are regulated by the High-Pressure Gas Safety Act, the storage and transportation supply level to general end-users are regulated by the LP Gas Act.

**Government policy on separation and unbundling of town gas transportation sectors**

As part of the Gas System Reform, as in the case of the Electric System Reform, for a town gas-related business, the legal unbundling of the transportation sector is scheduled for April 2022 to ensure the neutrality of all entities engaged in a gas-related business. This reform is expected to apply to three major players: Tokyo Gas, Osaka Gas and Tohou Gas. By April 2022, these companies will have to separate those sectors and transfer them to an affiliate or other entity.

**Obligations undertaken by general gas transportation companies**

Since gas pipelines are dominantly owned and operated by a few operators, such as the three major players, in order to secure the effective liberalisation of other sectors, general gas transportation business operators are prohibited from refusing to execute a transportation contract without reasonable grounds. Also, the terms and conditions of such contracts and amendments are required to be approved by the METI in advance.

**IV ENERGY MARKETS**

**i Japan Electric Power Exchange**

The Japan Electric Power Exchange (JEPX) exists for the benefit of all electric power-related transactions. It was founded on 28 November 2003 as a market for the commodity trading of electric power and serves as an intermediary for electric power spot trading, forward transactions and other similar transactions. (It is possible to undertake both buy and sell orders through the JEPX.) To participate in electric power commodity trading on the JEPX, membership as a trade affiliate is necessary. As of 1 April 2019, 161 companies were trade affiliates of the JEPX. As of 1 April 2019, JEPX has the spot market opening 365 days and established a market in which members can trade electricity until one hour prior to its actual use. This market enables electricity business entities to adjust the amount of electricity they provide until the last minute.

The JEPX is managed by a general incorporated association comprising electric power companies and other such entities. It is a private exchange that operates and is regulated by its own market rules.
ii Terms and conditions of supply

Electricity

As explained above, the amendment to the EBA that came into effect on 1 April 2016 liberalised entry into the electricity retail business, but provides a provisional measure that requires former general electric utilities (utilities allowed to retail electricity at low voltage market before the liberalisation) to continue to provide the existing terms and conditions until 2020 at earliest in order not to let the electricity price raise unreasonably. Additionally, all retail companies are subject to regulations in certain codes of conduct such as to deliver explanations and documents in relation to certain matters, for their supply to customers.

Gas

Obligation to supply

Similarly to the electricity sector, on 1 April 2017, entry into the town gas retail business was fully liberalised. However, certain town gas retail business operators specified by the METI shall continue to supply gas under the terms and conditions approved by the METI. Further, gas retail companies are also subject to regulations on certain codes of conduct such as to deliver explanations and documents regarding the terms of certain matters for their supply to customers.

No such obligations are imposed on LPG business operators.

iii Market developments

Electricity

In addition to the market for trading electric power commodity on the JEPX, the OCCTO is preparing to set up an auction system to trade the capacity to generate electricity in the future, which is called the capacity market. The first auction is expected to be held by the end of March 2021. It is expected that at the auction electricity generation business operators will submit bids for the capacity to generate electricity four years after the auction and the OCCTO will pick the operators and fix the price of electricity to secure the capacity to generate electricity four years after the auction and then pay the consideration to the operator. The amount of the consideration to be paid by the OCCTO to the operator will be borne by electricity retail business operators (i.e., electricity retail business operators will be required to contribute to the OCCTO to fund such amount).

The Amendment to the Commodity Futures Act that took effect in 2016 provides that electricity becomes subject to commodity futures trading, which enables market participants to avoid the risk of volatility. The Tokyo Commodity Exchange, Inc aims to launch an electricity future market according to its midterm management plan announced in November 2017.

An infrastructure fund market that enables the listing of funds that invest in certain infrastructure such as electric generation facilities, established by the Tokyo Stock Exchange, Inc in April 2015, has developed over the past four years. Following the first listing of an infrastructure fund in June 2016, five additional infrastructure funds were listed on the market. The six infrastructure funds invest in solar power facilities. The market provides opportunities for a broad range of investors, including retail investors, to invest in infrastructure-related investments and adds an option for developers who, in particular, develop large-size power facilities.
Gas
With respect to gas, no particularly noteworthy market developments are currently anticipated or under consideration.

V RENEWABLE ENERGY AND CONSERVATION
i Electricity
The Renewable Electric Energy Act
Japan has been subject to huge developments in the area of renewable energy. The Act on Special Measures concerning the Procurement of Renewable Energy Sources by Electric Utilities (the Renewable Energy Act) was enacted with the objective of introducing FITs (a system whereby the total volume of electricity should be purchased at a fixed price for a fixed term). The Renewable Energy Act became effective on 1 July 2012, and the FIT scheme has been amended several times since then to address certain issues (see ‘Increase in renewable electric energy generation and associated problems’ below). The major requirements for a generator to sell electricity at the fixed price under the FIT scheme can be summarised as follows:

a Execute an interconnection agreement with one of the general transmission companies or one of the specific transmission companies for its renewable energy generation facility.

b Obtain certification by the METI for its plan on the generation business relating to the renewable energy generation facility in accordance with the requirements under the Renewable Energy Act. Renewable energy, which is subject to the FIT scheme, is currently limited to certain renewable energy sources: solar, wind, water (currently statutorily limited only to small and medium hydroelectric generators with an output of less than 30,000kW), geothermal and biomass.

c Execute a power purchase agreement with one of the general transmission companies or the specific transmission companies for a renewable energy generation facility with the above certification. Such transmission companies are obliged to accept an offer by a generator to execute such a power purchase agreement, unless it falls into certain exceptions.

Sales prices and contract terms
Set out below are the changes in sales prices and contract terms granted by the FIT scheme in recent years. In relation to solar power, as a reflection of the sudden drop in price of solar panels, the sales price is falling (as per our further notes below). In comparison, measures have been taken to establish favourable pricing and to support investment in respect of offshore wind power and existing headrace tunnel-type medium and small-scale hydroelectric power generators. A bid system, which was newly adopted by the recent amendment, is applicable to facilities with (1) solar power of 500kW or more; and (2) biomass power (generated by certain wood or agricultural products with a capacity of 10MW or more or by biomass liquid fuel) as of 2019.
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<thead>
<tr>
<th>Electricity generated</th>
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<th>Contract term</th>
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</tr>
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<td>¥32</td>
<td>¥29</td>
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<tr>
<td></td>
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<td>(1 April to 30 June) or</td>
</tr>
<tr>
<td></td>
<td></td>
<td>¥27</td>
</tr>
<tr>
<td></td>
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<td>(after 1 July)</td>
</tr>
<tr>
<td>≥500kWh &lt;2,000kWh</td>
<td>¥32</td>
<td>¥29</td>
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<tr>
<td>≥20kWh</td>
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<td>≥5,000kWh &lt;30,000kWh</td>
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<td>Existing headrace tunneled-type medium and small-scale hydro electric power*</td>
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Increase in renewable electric energy generation and associated problems

Following the introduction of FITs, renewable source energy generation – solar power generation in particular – is increasing rapidly. Set out below are recent data on electricity generated by renewable source energy generation facilities and purchased by business operators (in million kWh).

On the other hand, problematic businesses, such as those that utilised favourable pricing to obtain facility certification from the METI but delayed commencement of work and attempted to obtain fraudulent profits, had been frequently reported. In response, the following amendments have been made:

a. the METI has placed conditions on certified solar power facilities since 2014, requiring them to secure the land title and procure the solar modules;

b. the Renewable Energy Act was amended on 1 April 2017 and as a result the certification for a plan for a generation business relating to a renewable energy generation facility will only be granted by the METI where the renewable energy generation facility reaches the stage of certain development, including the execution of an interconnection agreement with certain transmission companies and when there is the prospect of obtaining the necessary land titles;

c. any operators that execute a grid connection agreement after 1 August 2016 must commence operation of their project within three years from the date on which the certification was issued by the METI (the COD deadline) (the three-year rule). If an operator fails to meet the COD deadline, the commencement of the FIT period starts from the day following the COD deadline and the project will not be able to fully utilise the FIT period; and
on 5 December 2018, a new regulation was enforced on pre-operation of solar power projects, the METI ID of which is issued during the period from April 2012 to March 2015 and to which the three-year rule does not apply because a grid connection agreement was executed before 31 July 2016. Under the new regulation, (1) an application for the start of grid connection construction (GCCA) to a utility should be received by the utility by 31 March 2019 and (2) operation shall commence by 31 March 2020 (or, if the GCCA is received after 31 March 2019, one year after the GCCA is received by the utility).

Further, a rapid increase in renewable energy generation has caused a lack of capacity in transmission lines in some areas. Currently, new solar and wind-power projects in certain areas are subject to unlimited restrictions on the output from renewable energy generation facilities that satisfy certain requirements, including that they expect an oversupply of electricity. Kyushu Electric Power Company implemented the country’s first power curtailment of output on two consecutive days from 13 to 14 October 2018. Although transmission companies have recently embraced policies to expand the capacity of transmission lines, this issue is still yet to be fully resolved.

Environmental issues have been raised in relation to solar power projects, which include erosions of soils, effects of lights reflected by solar panels and deforestation. In light of the issues, on 17 January 2019, the Ministry of the Environment announced that it would subject solar power projects of 40MW or more to environmental assessment based on the relevant laws and regulations, which is expected to come into force from April 2020 or later. If the environmental assessment is in place, the assessment process could be a considerable burden on solar power projects of 40MW or more.

**Enactment of the Re-Energy Area Usage Act**

As Japan is an island nation, marine renewable energy businesses such as offshore wind power generation have been regarded as key businesses from the perspective of energy policy. However, there was no law providing for unified rules for long-term occupancy of general sea areas that are Japanese territories and inland waters. This had been an obstacle to commencing such businesses in these sea areas. To address this issue, on 30 November 2018, the Act on Promotion of Utilisation of Sea Areas for the Development of Marine Renewable Energy Generation Facilities (the Re-Energy Area Usage Act) was passed by the Diet and came into force on 1 April 2019. The Re-Energy Area Usage Act allows for the long-term use of certain designated general sea areas for the purpose of offshore wind renewable energy projects upon approval by the governmental agency, and is expected to promote such projects.

**Gas**

In terms of gas-related renewable energy, biogas has been generating a lot of attention in recent years. Biogas is a flammable gas produced by the fermentation of organic waste such as raw sewage, food waste and livestock excretions, a feature that allows it to be harvested at sewage treatment plants, food factories and other such locations. Major town gas utilities such as Tokyo Gas and Osaka Gas have in recent years established guidelines for and promoted the purchase of biogas. Additionally, several local governments began to produce biogas in a sewage facility or refuse disposal facility.
VI THE YEAR IN REVIEW

The electric power industry regulations have, following the events at Fukushima in 2011, already witnessed great reforms. First, the electric system reform started, including full liberalisation of entry into the electricity retail business, and the following phase of the reform, including legal unbundling of the electric power transmission function and sector from the existing dominant power suppliers, will be implemented in 2020. Second, the introduction of FITs has encouraged the emergence of new entrants to the renewable energy industry and the renewable energy market has been expanded, but the FIT system is being revised to address several problems, including a newly adopted bid pricing system for solar power generation of a certain size and for biomass power generation of a certain type and certain size.

As explained above, the gas system was reformed along the same lines as the electric system reform, and from April 2017 the full liberalisation of entry into the gas retail business was implemented and new regulations for gas transportation businesses (especially general gas transportation businesses) have been imposed to make gas pipelines available to gas retail business operators. Furthermore, from 1 April 2022, the gas transportation (pipeline) business sector of three major companies (Tokyo Gas, Osaka Gas and Tōhoku Gas) will be unbundled.

Two remarkable trends in renewable energy have been seen. The Re-Energy Area Usage Act came into force on 1 April 2019 to allow the long-term use (up to 30 years) of certain general sea areas for offshore wind power projects. In addition, a bid that was implemented on solar power of 2,000kW in 2018 resulted in ¥14.25 at its lowest bid price.

VII CONCLUSIONS AND OUTLOOK

The events at Fukushima in 2011 served as the main catalyst for the reforms that the electric power industry has recently been facing. The full extent of these reforms and their effects, however, remains to be seen. As of 31 March 2019, all 48 nuclear power stations in Japan except nine are stopping operations. In the meantime, the Nuclear Regulation Authority issued new nuclear power station safety standards in July 2013 and, as of December 2018, 12 nuclear power stations are in the process of review for restart under the new safety standards (15 stations have already passed). However, it is still unclear when and how many nuclear power stations will restart operations.

Under these circumstances, Japan will become increasing reliant on its remaining sources of energy, that is, oil and LNG. These traditional sources of fuel are regarded as more stable and reliable; however, because they are ultimately non-renewable resources, this in and of itself introduces an entirely different set of issues. At the end of the day, Japan's energy requirements may push it in the direction of renewable energy such as those discussed above. The output of such energy sources is, however, substantially smaller compared with nuclear energy, not to mention inherently unstable and less reliable. Accordingly, Japan's demand for alternative and reliable sources of energy may even result in renewed interest in the gas industry, which in turn will surely lead to further developments in this field.

With all facets of the energy industry shifting so rapidly at the moment, the only thing that can be said with any certainty is that change is imminent. Exactly how and what form this change will take remains to be seen, and it is certainly worth keeping a close eye on Japan in the years to come.
Chapter 15

KOREA

Soong-Ki Yi, Kwang-Wook Lee and Changwoo Lee

I OVERVIEW

Korea relies on over 97 per cent of its primary energy sources from overseas acquisition, and fossil fuels, such as petroleum, gas and coal account for 85 per cent of these sources. Therefore, there are policy needs in the short term to take measures against fluctuations in the supply and demand for energy based on global factors, and in the long term to take measures against the depletion of fossil fuels. The 2011 Fukushima nuclear power plant accident in Japan has served as a warning to carefully consider the use of nuclear energy policy and the new energy environment, and the effects of climate change, has increased the use and interest in new and renewable energy.

Under the current environment and policy needs, Korea has designated the Energy Act and Framework Act on Low Carbon and Green Growth (the Framework Act) as its basic laws. These energy laws were prepared with the intention of achieving certain policy goals such as having a steady supply of energy, eco-friendliness, market principles and energy security, and these goals are being implemented in line with the changes to the energy market and environment through the enactment and amendment of individual laws.

The Korean government is strengthening the competitiveness of the renewable energy industry to the level of advanced countries with the aim of completing energy conversion with its own technology and fostering various new energy businesses including those related to energy efficiency, dismantling nuclear power and electric power brokerage. The government is focusing on the development of technologies to upgrade the systems of solar power, which is the most promising of the renewable energy sources. The government also enhances the competitiveness of the components required for wind-power generation. In the field of energy efficiency, the government has introduced the lowest efficiency standards for electric motors, chillers and air compressors, and is building up a national infrastructure for the Smart Grid. In addition, the government is endeavouring to further create new energy business fields, such as the full-scale dismantling of nuclear power plants and the opening of a small-scale renewable energy power brokerage market.
II REGULATION

i The regulators

Regulators

The Ministry of Trade, Industry and Energy (MOTIE) is in charge of all regulations regarding individual energy resources (e.g., electricity, petroleum and gas). In particular, the MOTIE carries out duties regarding entry regulations for individual energy resources with respect to licences, reporting and registration. Among the individual energy resources, with respect to electricity, the Electricity Regulatory Commission is an affiliated organisation within the MOTIE that was formed to, inter alia, decide on granting approval and licences for electric utility businesses, electric business acquisitions and other matters.

The Korea Power Exchange (KPX) is in charge of duties regarding establishing or managing the electricity market, and duties regarding transactions involving electricity, etc.

Further, the Prime Minister’s Office is in charge of matters related to the Framework Act, which is a basic law regarding the macroscopic energy policy, and the Energy Commission, which is an affiliated organisation within the MOTIE, was formed to, inter alia, deliberate over matters regarding important energy policies and plans. The Ministry of Environment and the Ministry of Foreign Affairs are also involved in energy-related policies such as establishing emissions-trading systems, clean energy and climate change, as well as joining international treaties.

Main sources of law and regulation

The Framework Act, which was enacted in January 2010, is a general law regarding energy policies. In the past the Energy Act was the general law regarding energy policies, but after the enactment of the Framework Act, several of its provisions were transferred to the Framework Act. The Framework Act establishes or promotes comprehensive government energy policies and national strategies, including solutions to climate change and energy issues, expansion of growth and development, strengthening the competitiveness of companies, efficient use of land and creation of a pleasant environment (Article 3(1)).

The Energy Act still regulates matters such as the establishment of regional energy plans and emergency energy plans and the establishment and operation of the Energy Commission.

Individual energy resources and the related businesses are regulated pursuant to the following laws:

a Electricity: the Electric Utility Act (EUA) regulates matters such as the production, distribution and sale of electricity and the Electrical Construction Business Act was enacted to ensure the safety of businesses that engage in electricity-related construction.

b Petroleum and gas: the Petroleum and Petroleum Substitute Fuel Business Act (PBA) and the Urban Gas Business Act (UGBA) regulate the adequate distribution of petroleum and gas to consumers, and the High-Pressure Gas Safety Control Act was enacted to introduce safer measures to prevent the possibility of gas exploding.

c Nuclear energy: the Nuclear Energy Promotion Act regulates the research, development, production and use of nuclear energy; the Nuclear Safety Act regulates the safety of nuclear energy; and the Nuclear Damage Compensation Act regulates matters regarding damage compensation arising in relation to nuclear energy.
New and renewable energy: the Act on the Promotion of the Development, Use and Diffusion of New and Renewable Energy (the New and Renewable Energy Act) acts as the basic law regarding the development of technology for new and renewable energy as well as the use and dissemination of new and renewable energy.

ii Regulated activities

Electricity

Under the EUA, electric utility businesses are categorised into five types of business, the definitions of which are as follows:

a Electricity generation business: a business, the main purpose of which is to generate and supply electricity to operators of the electricity sales business via the electric utility market.2

b Electric transmission business: a business, the main purpose of which is to set up and operate electric installations necessary to transmit electricity produced at power stations to operators of the electricity distribution business.3

c Electric distribution business: a business, the main purpose of which is to establish and operate electricity installations necessary to distribute electricity transmitted from power stations to consumers of electricity.4

d Electric sales business: a business, the main purpose of which is to deliver electricity to consumers.5

e District electric business: a business, the main purpose of which is to generate electricity with electric generating units of up to 35,000kW to meet the demand of a specific supply district, and to supply the produced electricity to consumers of electricity in that specific supply district, not via any electric utility market.6

The Korea Electric Power Corporation (KEPCO) had a monopoly on the production and supply of electricity in Korea until the late 1990s, and was entirely responsible for generation, transmission, distribution and sales. Currently, KEPCO is still responsible for transmission, distribution and sales of electricity, KEPCO’s subsidiaries and various private companies are competing in the electricity generation business.

According to Article 7 of the EUA, any person who intends to operate an electric utility business must obtain a licence, based on the business type, from the Minister of the MOTIE (the Minister); the Minister’s approval is required when the person intends to modify important matters relating to the licence, such as the business district or specific supply district, supply voltage and, in the case of electricity generation businesses and district electric businesses, the place of electric installations, equipment capacity and the type of motive power.7 To obtain a licence, the following documents must be submitted to the Minister:8

a an application for a licence;

b a business plan;

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2 Article 2(iii) of the EUA.
3 Article 2(v) of the EUA.
4 Article 2(vii) of the EUA.
5 Article 2(ix) of the EUA.
6 Article 2(xi) of the EUA; Article 1-2 of the Enforcement Decree of the EUA.
7 Article 7(1) of the EUA; Article 5(1) of the Enforcement Rule of the EUA.
8 Article 7(1) of the EUA; Article 4(1) of the Enforcement Rule of the EUA.
The Minister will grant electricity utility licence after an application has undergone deliberation by the Electricity Regulatory Commission. The criteria for issuing the licence as provided by Article 7(5) of the EUA are:

- to have the financial and technological capability necessary to operate the electric utility business in the optimal manner;
- to be able to carry out the electric utility business as planned;
- all or a part of two or more business zones for operators of the electric distribution business or specific supply districts for operators of the district electric business must not overlap;
- in the case of district electric businesses, to meet at least 50 per cent of the electricity demand of a specific supply district and not to constitute any obstacle to the supply of electricity by another operator to consumers residing in the neighbouring area because of that business;
- power plants and power generation fuel must not be concentrated in certain areas to disrupt the power system; and
- to conform with the standards set by the Enforcement Decree of the EUA on the basis of public necessity.

An operator of the electric utility business must set up the electric installations necessary to operate the electric utility and start up the business within the preparation period determined by the Minister.9

The EUA requires the Minister to take into consideration the economic efficiency of the electric installations and their impact on the environment and public safety when establishing a basic plan for electric supply.10

**Petroleum**

Article 2 of the PBA defines the term ‘petroleum’ as ‘crude oil, natural gas (including liquefied natural gas)’ and ‘petroleum products’ as ‘gasoline, kerosene, diesel, fuel oil, lubricating oil, hydrocarbon oil and petroleum gas (including liquefied petroleum gas)’11 and categorises petroleum businesses into three types of business: petroleum refinery businesses,12 petroleum export and import businesses13 and petroleum sales businesses.14

Anyone who intends to operate a petroleum refinery business must register his or her business with the Minister by submitting an application for registration and a business plan to the Korea Petroleum Quality and Distribution Authority, which was established pursuant

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9 Article 9(1) of the EUA.
10 Article 3(2) of the EUA.
11 Article 2(i) and (ii) of the PBA.
12 Article 2(iv) of the PBA.
13 Article 2(v) of the PBA.
14 Article 2(vi) of the PBA.
to Article 25-2 of the PBA. In connection with petroleum refinery businesses, anyone who intends to operate a business for manufacturing asphalt, base oil and lubricant must report the business to the Minister.

Also, anyone who intends to operate a petroleum export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration, a business plan and import agent agreement to the Korea Petroleum Quality and Distribution Authority. Such a registration, however, is not required for a person who is already registered as an operator of a petroleum refinery business, and for the import and export of certain petroleum products such as asphalt, lubricant and base oil. To qualify for the registration of a petroleum export and import business, an applicant must be equipped with a storage facility capable of storing the greater of the quantity of 15 days’ worth of planned domestic petroleum sales or 2,500kL. The previous storage capacity requirement of the greater of the quantity of 30 days’ worth of planned domestic petroleum sales or 5,000kL has been relaxed to the current requirement since December 2016 to induce price cuts by lowering entry barriers to the petroleum export and import business and thus promoting price competition among petroleum products both domestic and foreign.

Petroleum sales businesses are classified into (1) general agents and solvent agents; (2) gas stations; (3) solvent vendors; (4) manufacture and sales businesses of petroleum by-products; (5) secondary fuel oil vendors; and (6) general vendors, aviation fuel sales business and special vendors. While (1) to (5) need to be registered with the head of the local government, petroleum sales businesses that fall under (6) need to be reported to the head of the local government.

To facilitate integrated controls and regulations of liquefied petroleum gas businesses, the PBA excludes liquefied petroleum export and import business from petroleum export and import business. To further protect consumers of petroleum products, the PBA prohibits the sale of petroleum and petroleum alternative fuels whose volumes have been improperly increased by artificial heating, and punishes violations. In addition, the PBA adds the Customs Office as an agency from which the Minister of the MOTIE may request tax information for efficient supervision and monitoring of conducts that may disrupt sound distribution of petroleum products in the market or violate prohibition against manufacturing of fake petroleum products.

15 Article 5(1) of the PBA; Article 4(1) of the Enforcement Rule of the PBA.
16 Article 5(2) of the PBA; Article 8(1) of the Enforcement Decree of the PBA.
17 Article 9(1) of the PBA; Article 8(1) of the Enforcement Rule of the PBA.
18 Article 9(1) of the PBA; Article 10(2) of the Enforcement Decree of the PBA.
19 Article 12(1) of the Enforcement Decree of the PBA.
20 Article 10(1) of the PBA; Article 12(1) to (6) of the Enforcement Rule of the PBA.
21 Article 10(2) of the PBA; Article 12(7) of the Enforcement Rule of the PBA.
22 Article 9(1) of the PBA.
23 Article 39(1)(iii) of the PBA.
24 Article 41-3 of the PBA.
Urban gas

The UGBA defines the term ‘urban gas’ as natural gas (including liquefied gas), petroleum gas, by-products from naphtha cracking and biogas, and synthetic natural gas (SNG). Under the UGBA, urban gas businesses are categorised into five types of businesses: gas wholesale business, general urban gas business, urban gas recharging business, by-products from naphtha cracking and biogas manufacturing business, and SNG manufacturing business.

Besides the above, recently, there has been very active development of shale gas. To allow private businesses to flexibly take appropriate measures and seek new business opportunities in response to the changes in the international energy market, such as the expansion of the Northeast Asia LNG purchase market, a reporting system was implemented for businesses that carry natural gas in and out, and the sale of natural gas abroad for self-consumption by a direct importer (which imported the natural gas) is permitted.

According to the UGBA, the definition of each urban-gas business is as follows:

- **Gas wholesale business:** a business by which urban gas is supplied by a person, other than an operator of general urban gas businesses or by-products from naphtha cracking and biogas manufacturing businesses, to general urban gas business operators, urban gas recharging business operators or large users.
- **General urban gas business:** a business that supplies urban gas supplied by gas wholesale business operators, or petroleum gas, by-products from naphtha cracking or biogas produced by the general urban gas business operator itself, to users through pipelines according to the general demand.
- **Urban gas recharging business:** a business that supplies urban gas supplied by gas wholesale business operators, or by-products from naphtha cracking or biogas produced by the urban gas recharging business operator itself, by recharging the gas in a container, storage tank or tank fixed to a vehicle.
- **By-products from naphtha cracking and biogas manufacturing business:** a business that manufactures by-products from naphtha cracking and biogas itself for self-consumption or supplies to gas wholesale dealers or general urban gas businesses (except for a business that manufactures naphtha by-products with manufacturing permit as required under Article 4 of the High Pressure Gas Safety Control Act and supplies by-product gas through dedicated piping directly to such facilities designated under the MOTIE Ordinance).
- **SNG manufacturing business:** a business that manufactures SNG itself for self-consumption, supplies to gas wholesale dealers or supplies to a party that holds the majority of the shares of the applicable SNG manufacturing business for the parties’ self-consumption.

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25 Article 2(i) of the UGBA; Articles 1–2 of the Enforcement Decree of the UGBA.
26 Article 2(i) of the UGBA.
27 Article 2(i-2) of the UGBA.
28 Article 2(ix-2) and (ix-3); Article 10-2(3) of the UGBA.
29 Article 10-6 of the UGBA.
30 Article 2(iii) of the UGBA.
31 Article 2(iv) of the UGBA.
32 Article 2(iv-2) of the UGBA.
33 Article 2(iv-3) and Article 8-3 of the UGBA.
34 Article 2(iv-4) of the UGBA.
Natural gas export and import business: a business exporting or importing natural gas.\textsuperscript{35}

Business that carries natural gas in and out: a business pursuant to Article 154 of the Customs Act that carries natural gas in or out from the storage facility in the bonded area.\textsuperscript{36}

Under the UGBA, a person who intends to operate a gas wholesale business must obtain a licence from the Minister of the MOTIE\textsuperscript{37} and a person who intends to operate general urban gas business must obtain a licence from the head of the local government.\textsuperscript{38} A licence for the gas wholesale business and general urban gas business will only be granted if applications meet the following requirements:\textsuperscript{39} (1) the relevant urban gas business is of an economic scale appropriate for the public interest and general demand; (2) the relevant applicant has financial resources and technical capability necessary to properly conduct such an urban gas business; and (3) the relevant applicant has the capability of establishing and maintaining appropriate supply facilities for the stable supply of urban gas. A person who intends to operate an urban gas recharging business and by-products from naphtha cracking and biogas manufacturing business must obtain a licence from the head of the local government for each place of business.\textsuperscript{40} A person who intends to operate an SNG manufacturing business must obtain a licence from the Minister for each place of business.\textsuperscript{41}

Anyone who intends to operate a natural gas export and import business must register his or her business with the Minister 30 days prior to the expected date of the initial customs clearance, by submitting an application for registration and a business plan (including current status or construction plan of the storage facility of natural gas and a supply plan for the five years following the year of the import of natural gas).\textsuperscript{42} If a natural gas export and import business operator who is an urban gas business operator intends to conclude a natural gas import, export or transportation agreement, he or she must obtain approval from the Minister after meeting the urban gas requirements in relation to demand and supply, and appropriateness of price.\textsuperscript{43} Anyone who intends to operate a business that carries natural gas in and out must report the business to the Minister.\textsuperscript{44}

On the other hand, the UGBA includes provisions to improve regulations on natural gas export and import business operators, and to strengthen safety requirements. In addition, to flexibly respond to natural gas supply and demand situations at home and abroad, the UGBA exempts natural gas import agreements that meet certain criteria from the requirement to obtain pre-approval from the Minister. With respect to these natural gas import agreements, the importers are required to report to the Minister only after concluding the agreements.\textsuperscript{45} The UGBA strengthens safety requirements by stipulating that, in cases where liquefied

\textsuperscript{35} Article 2(vii) of the UGBA.
\textsuperscript{36} Article 2(ix-2) of the UGBA.
\textsuperscript{37} Article 3(1) of the UGBA.
\textsuperscript{38} Article 3(2) of the UGBA.
\textsuperscript{39} Article 3(7) of the UGBA.
\textsuperscript{40} Article 3(3) of the UGBA and Article 3(4) of the UGBA.
\textsuperscript{41} Article 3(5) of the UGBA.
\textsuperscript{42} Article 10-2(1) of the UGBA; Article 10-6 of the Enforcement Rule of the UGBA.
\textsuperscript{43} Article 10-5(1) of the UGBA.
\textsuperscript{44} Article 10-2(3) of the UGBA.
\textsuperscript{45} Article 10-5(2) of the UGBA.
petroleum gas facilities are changed into urban gas facilities, urban gas operators and gas users must implement certain safety measures such as demolition of liquefied petroleum gas containers and ancillary equipment. The UGBA imposes penalties for violations of the safety requirements, and even gas users who fail to comply with the safety requirements will be subject to penalties.\(^{46}\) The UGBA also requires that safety measures for gas plumbing and gas use facilities be implemented in the case of an extension or alteration to a building where urban gas pipelines are installed.\(^{47}\) The UGBA also newly introduces penalty provisions against those parties that cause damage, or inflict harm to the functionality of, urban gas pipelines.\(^{48}\)

**New and renewable energy**

The New and Renewable Energy Act authorises the Minister of the MOTIE to establish a basic plan to promote use, dissemination and technological development of new and renewable energy every five years after consultation with the head of the relevant central administrative agency and deliberation by the New and Renewable Energy Policy Council.\(^{49}\) Also, to achieve the goals set out in the basic plan, plans for implementation must be established and carried out for each type of new and renewable energy every year.\(^{50}\)

The New and Renewable Energy Act provides that tradable renewable energy certificates (REC) will be issued to new and renewable energy suppliers. On the other hand, in cases where new and renewable energy suppliers receive support from the MOTIE in an amount equal to the balance between the trading price of the electric power supplied by new and renewable energy sources and the standard price announced by the MOTIE, RECs will be issued to the state. The MOTIE may trade the certificates issued to the state in the market to keep the balance of demand and supply and to stabilise prices.\(^{51}\) In addition, the New and Renewable Energy Act abolishes the renewable energy installation specialist system and the renewable energy building certification system, which have been found to be ineffective, and integrates the renewable energy facility certification system into the Korean Industrial Standards certification system under the Industrial Standardisation Act.\(^{52}\)

To ensure the adequate quality of new and renewable energy fuels, the New and Renewable Energy Act authorises the Minister of the MOTIE to announce quality standards for new and renewable energy fuels, and requires that new and renewable energy suppliers must pass a quality inspection for new and renewable energy fuels by a designated quality inspection agency.\(^{53}\) The New and Renewable Energy Act also introduces renewable fuel standards that require petroleum refinery operators and petroleum exporters to mix more than a certain percentage of new and renewable energy fuel in fuel for transport. Violations of these requirements may be punished by civil fines.\(^{54}\) Moreover, the New and Renewable Energy Act requires a new and renewable energy facility certification holder to take out

\(^{46}\) Article 28-2 and 54(6) of the UGBA.

\(^{47}\) Article 28-3 of the UGBA.

\(^{48}\) Article 48(4) and (8) of the UGBA.

\(^{49}\) Article 5(1) and (2) of the New and Renewable Energy Act.

\(^{50}\) Article 6(1) of the New and Renewable Energy Act.

\(^{51}\) Article 12-7 of the New and Renewable Energy Act.

\(^{52}\) Article 13 of the New and Renewable Energy Act.

\(^{53}\) Article 12-11, 12-12 of the New and Renewable Energy Act.

an insurance policy against damage to be suffered by a third party.\textsuperscript{55} Under the New and Renewable Energy Act, new and renewable energy suppliers may join a mutual aid association for the purpose of developing new and renewable energy technology and facilitating new and renewable energy business operations.\textsuperscript{56}

iii Ownership and market access restrictions

Article 96 of the EUA provides that a foreign-capital invested company under the Foreign Investment Promotion Act may not obtain a licence for an electricity generation business under Article 7(1) of the EUA (this restriction is limited to the operation of atomic power stations) or approval for a plan for the manufacture and supply of fuel for atomic power generation under Article 28 of the EUA. There is no other restriction on foreign-capital invested companies with respect to the operation of electric utility businesses. The PBA and UGBA do not contain any provisions limiting foreign-capital invested companies’ operation of the relevant businesses.

iv Transfers of control and assignments

With respect to an electric utility business, if a person intends to acquire all or part of an electric utility business from its operator or to divide or merge an electric utility company or to acquire more than a certain percentage of shares in an electric utility company (except for those with power capacity less than 20,000kW) to ensure management control, it must obtain approval from the Minister.\textsuperscript{57} There are no particular restrictions on the acquisition, division or merger of petroleum businesses and urban gas businesses.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electric power

In Korea, KEPCO, which was established pursuant to the Act on the Korea Electric Power Corporation, initially had a monopoly on the production and supply of electricity as the Korean government decided that, to protect the public interest, it would be appropriate for a public corporation to conduct the business of generating and distributing electricity. The supply of electric power, however, became unstable from the late 1980s because of a rapid increase in the demand for electricity, so the Korean government enacted the Act on the Promotion of the Reorganisation of Electric Power Industry in 2000 and privatised the electricity generation business by dividing KEPCO’s electricity generation business into six subsidiaries. As of January 2019, the number of private companies participating in the electricity market is 2,894.

\textsuperscript{55} Article 13-2 of the New and Renewable Energy Act.
\textsuperscript{56} Article 30-2 of the New and Renewable Energy Act.
\textsuperscript{57} Article 10(1) of the EUA.

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Urban gas

The UGBA has various provisions that regulate the proper management of the supply and consumption of urban gas, which is public property. A general urban gas business operator and gas wholesale business operator must prepare and submit to the head of the local government a gas supply plan for five years.

ii Transmission/transportation and distribution access

Electric power

According to the EUA, only members of the KPX are entitled to carry out electric utility transactions at the electric utility market and, other than a consumer who uses 30,000kVA or more, no consumer may purchase electricity directly from the electric utility market. Accordingly, electricity produced by electricity generation business operators must be supplied to electricity consumers by operators of electric transmission, distribution and sales businesses. The EUA further provides that no operator of the electricity generation business and electric sales business or no electric vehicle charging network operator may refuse to supply electricity without just cause as prescribed by the Enforcement Decree of the EUA and the operator of an electric utility business must maintain the quality of service that it provides. Moreover, operators of electric transmission businesses, electric distribution businesses and district electric businesses must be equipped with and maintain and manage installations meeting the standards determined and publicly notified by the Minister so as to smoothly transmit or distribute electricity regardless of changes in the supply and demand of electricity.

Petroleum

The PBA has various provisions that regulate the management of the quality of petroleum products and prevent the distribution of pseudo-petroleum products. In the event that a petroleum refinery business operator, petroleum export and import business operator or a registered petroleum sales business operator intends to sell or deliver certain petroleum products (e.g., petrol for vehicles, kerosene, light oil, petroleum by-products), the operator must have the petroleum products inspected by a quality inspection institution appointed by the Minister. Any operator will be prohibited from selling or delivering petroleum products that have failed the quality inspection. According to Article 29(1) of the PBA, no one may engage in manufacturing, importing, storing, transporting or keeping pseudo-petroleum products.

58 Article 44 of the EUA.
59 Article 32 of the EUA; Article 20 of the Enforcement Decree of the EUA.
60 Article 14 of the EUA.
61 Article 18(1) of the EUA.
62 Article 27 of the EUA.
63 Products manufactured by a method of mixing petroleum products with other petroleum products or petrochemicals; Article 2(x) of the PBA.
64 Article 25(1) of the PBA; Article 28(1) of the Enforcement Rule of the PBA.
65 Article 27 of the PBA.
Meanwhile, to promote the expansion of the exporting of petroleum products, Article 29(2)(v-2) of the PBA stipulates that the blending of petroleum products at the general bonded area for the purpose of export only, as well as storing and transporting such mixtures, will not be viewed as the manufacturing of fake petroleum products.66

Urban gas
No gas wholesale business operators shall refuse to supply natural gas, or have the supply thereof interrupted, to general urban gas business operators, urban gas charging business operators or bulk buyers without justifiable cause.67

Each urban gas business operator must have the urban gas that it supplies inspected by an urban gas quality inspection institution to confirm that the gas fulfils the required quality standards.68

iii Rates

Electric power
An operator of an electric sales business must prepare terms and conditions concerning electric utility charges and other conditions of supply (i.e., supply districts, type of supply and supply voltage and frequency), and obtain approval from the Minister.69 Further, an operator of the electric sales business must specify the details of the utility charges based on items in electric utility bills charged to consumers of electricity.70 An operator of the electric transmission business or electric distribution business must set charges for the use of electric installations and other matters concerning the conditions of their use.71

Petroleum
A petroleum refinery business operator, petroleum export and import business operator and petroleum sales business operator must report their sale prices of petroleum products to the Minister.72

Urban gas
A general urban gas business can have a party that is requesting a change in the contract regarding the supply of urban gas or supply of gas pay for all or a portion of the installation costs of the gas supply equipment or facilities (Article 19-2). Also, where it is difficult to supply urban gas for any of the reasons stipulated under Article 19, the national and local government can pay for all or a portion of the installation costs (Article 19-3). Gas wholesale business operators must obtain the approval of the Minister of the MOTIE in determining the rate. When a determined rate is changed, the same approval is required (Article 20(1)).

66 Article 29(2)(v-2) of the PBA.
67 Article 19 of the UGBA.
68 Article 25-2(1) of the UGBA.
69 Article 16(1) of the EUA; Article 16(1) of the Enforcement Rule the EUA.
70 Article 17 of the EUA.
71 Article 15(1) of the EUA.
72 Article 38-2(1) of the PBA.
Security and technology restrictions

Electric power

Where an operator of an electric utility business intends to perform the works for setting up or altering electric installations for the electric utility, he or she must obtain approval for the plan for the works from the Minister, and undergo periodic inspections conducted by the Minister.

New and renewable energy

If the Minister of the MOTIE deems it necessary for the promotion of the use and supply of new and renewable energy or to increase the vitality of the new and renewable energy business, it may make it mandatory for a party that holds over 500,000kW of generating units (excluding equipment for new and renewable energy), the Korea Water Resources Corporation and the Korea District Heating Corporation to use new and renewable energy with respect to a determined generation quantity per year within the scope of 10 per cent of the total power production amount for supply energy. Where the Minister of the MOTIE deems that the above party with the obligation to supply did not fulfil its obligation by not using sufficient new and renewable energy in supplying its energy, the Minister may impose an administrative fine.

ENERGY MARKETS

Development of energy markets

Electricity

As previously described, transactions regarding electricity take place at the KPX pursuant to the EUA, which was established as an independent legal entity on 2 April 2001. Specifically, transactions occur between the over 1400 electricity generation business operators and a sales business operator 24 hours a day and 365 days a year, based on prices that change every hour.

Gas

Gas is divided into the wholesale sector and retail sector. The Korea Gas Corporation is in charge of business in the wholesale sector, and regional urban gas companies are in charge of business in the retail sector. Specifically, through the main line operated by the wholesaler operator (i.e., the Korea Gas Corporation), gas is supplied to the general urban gas companies, and urban gas companies supply consumers through the pipes that are operated regionally. Because of the public nature of the gas business, the central government oversees and supervises each of the duties of the wholesaler operator and local governments oversee and supervise each of the duties of retail operators.

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73 Article 61(1) of the EUA.
74 Article 65 of the EUA.
75 Article 12-5(1) and (2) of the New and Renewable Energy Act; Article 18-3 of the Enforcement Decree thereof.
76 Article 12-6(1) of the New and Renewable Energy Act.
Korea

ii Energy market rules and regulation

Electricity

Electricity is regulated by the EUA. Electricity transactions must be made through the KPX and users of electricity cannot directly purchase electricity from the power market (EUA, Article 31). Electricity transactions are regulated by the Power Market Operating Regulations as determined by the KPX, pursuant to Article 43 of the EUA, and Article 53 of the EUA authorises the Electricity Regulatory Commission to adjudicate on disputes concerning the Regulations.

KEPCO has been monopolising the electric power brokerage business. However, pursuant to the amended EUA (Article 43-2 of the EUA and Article 1-3 of the Enforcement Decree of the EUA), small-scale electric power brokers may sell renewable energy under 1,000kW or electricity generated and stored in energy storage systems (ESS) and electric vehicles. Small-scale electric power brokers may enter into the market more easily now as they can commence their business after registration. They are not required to obtain approval as existing electricity businesses are. Such deregulation of market entry is expected to lead to the effective management of small-scale power resources and to improve the stability of the power sector.

Gas

Gas is regulated pursuant to the UGBA. Prior to the 2014 amendment of the UGBA, the direct importing of natural gas by private companies was allowed solely for private consumption. Aside from direct importing by private companies for a limited purpose, the importing and wholesale of natural gas was exclusively conducted by the Korea Gas Corporation (KOGAS). However, the 2014 amendment of the UGBA enabled private companies to resell natural gas they had directly imported. Direct imports of natural gas are expected to reach 4.65 million tons in 2017, accounting for 12 per cent of domestic natural gas demand. This amount is expected to more than double in 2031.

iii Contracts for sale of energy

Electricity

The price on the electricity market is determined based on the electricity demand price predicted by the KPX a day in advance and the supply bid price of the electricity generation business operators. The electricity charge (the sales price of businesses that sell electricity), however, is approved by the government pursuant to laws such as the EUA, as opposed to supply and demand, because of its public nature. After a large-scale power outage in Korea on 15 September 2011, electricity costs were increased a total of four times until November 2013. The main reason for the increase was the need to align costs with actual usage. In particular, in November 2013 electricity costs increased by an average of 5.4 per cent and, included in this, the industrial electricity cost increased by 6.4 per cent. Since that time, there has been no further increase or decrease in electricity rates. According to the Second Basic Energy Plan confirmed in January 2014, besides classifying electricity rates based on use (e.g., industrial, general and housing), as was done in the past, seasonal or time differential pricing has also been introduced.
In 2017, KEPCO has resolved to amend its Implementation Rules of General Terms and Conditions of Supply to expand new and renewable energy and ESS by modifying renewable energy discount standards, introducing new incentive to install new and renewable energy and ESS together, and extending new and renewable energy and ESS discount periods.

Gas
The transacting price in the wholesale sector is determined based on the contracts executed between the KOGAS and urban gas companies. Since the KOGAS imports all of its gas, it is directly or indirectly regulated by the government regarding the import volume and conditions. With respect to the issue of whether to strengthen or relax regulations on importing gas, there are differences in views between the government (which favours relaxation) and the National Assembly (which favours strengthening). In the retail sector, approval of the charge is required from local governments.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The Act on Promotion of Alternative Energy was enacted in the 1980s, and the government later established its comprehensive support policy, the Basic Plan for Technical Development for Alternative Energy (1988–2001). Also, to achieve its efficient promotion, the government established the Alternative Energy Business Department within the Korea Energy Management Corporation as the organisation in charge of the development of new and renewable energy.

In the 1990s, to prepare for the Climate Change Convention, the comprehensive technology development plan for energy and the environment, the Energy Technology Development 10-Year Plan (1997–2006), was established to establish a system to promote technological development of not only new and renewable energy, but also to help saving energy, and develop clean energy and resource technology.

As 2000 approached, there was a new understanding of the importance of new and renewable energy and, to strengthen policies regarding technical development and its increased use, the Act on Promotion of Alternative Energy was amended to become the Act on Promotion of Development, Use and Diffusion of Alternative Energy. This Act served to form the basis for business promotion regarding feed-in tariffs (FITs) for new and renewable energy general output, an obligation for public institutions to use new and renewable energy and new and renewable energy equipment certification procedures, etc., which made it possible to create an early market for new and renewable energy.

The Basic Plan for Development and Use of New and Renewable Energy (2003–2012) was established and implemented for the further promotion of new and renewable energy development and dissemination, and the relevant law was again amended in 2004. Korea applied FITs from 2002, but in 2012 they were replaced by the Renewable Portfolio Standard (RPS), which obligates certain operators of energy businesses to supply certain amount of new and renewable energy.

As of 2017, renewable energy accounted for 5.45 per cent of Korea’s electricity generation, which is lower than other major countries. In December 2017, the government set the goal of increasing the proportion of renewable energy to 20 per cent by growing the capacity of renewable energy facilities to 63.8GW by 2030. In order to achieve this goal, the government plans to promote:

a city-type private solar power for one household per 15 households by 2030;
small-scale projects under 100kW through introducing the Korean FiT, which combines the advantages of existing RPS and FiT;
project in rural areas utilising subprime farmland; and
large-scale project development with policy support.

The sources of renewable energy in Korea, as of 2017, are waste (57 per cent), bio (22 per cent), and solar (9 per cent). In order to reduce the proportion of non-renewable wastes, the government will improve the licencing system for energy businesses by mandating environmental impact assessments. The government will also exclude non-renewable wastes from the scope of renewable energy and ensure that more than 95 per cent of new power plants will supply clean energy such as solar power and wind power.

The government plans to leverage renewable energy as an opportunity to foster new energy businesses. For that purpose, the government will:
- set up an R&D roadmap to reduce the price of solar and wind power, to catch up with new technology and to acquire a competitive edge in next-generation technology;
- pursue strategic pilot projects to demonstrate new technologies, to verify business models and to promote pre-emptive deregulation;
- create renewable energy innovation growth clusters; and
- establish a comprehensive support system for promoting overseas market entry.

Furthermore, in order to foster new energy industries based on small-scale distributed power such as solar power and wind power, the government also plans to establish an intelligent power grid and ‘internet of things’ (IoT) infrastructure and strengthen certification standards. In doing so, the government is expected to induce the creation of new service industries based on the advanced power infrastructure and IoT technology, and to foster the new services industries through smart-city business models.

ii Energy efficiency and conservation

In 1995, the government established the use of demand management investment plans for energy suppliers pursuant to Article 12 of the Energy Use Rationalisation Act (Article 9 in the current version of the Act) and these plans have been in use since 1996 by companies such as KEPCO, the KOGAS and the Korea District Heating Corporation. Meanwhile, because of the restructuring and privatisation of the electricity industry, and based on the amendments to the EUA, the government established the groundwork formation plan for the electricity industry in December 2000, which, with the government funds for this groundwork, separately promotes demand-side management businesses.

Under the electricity demand management policy, which was established to achieve a stable supply and demand of electricity and efficient electricity use, the representative businesses are divided into load-management businesses, which reduce the maximum electricity demand, and energy-efficiency businesses, which reduce electricity consumption through high-efficiency devices. In terms of gas and heating, for the management of a stable supply and demand, there is an emphasis on the dissemination of gas-cooling and cogeneration facilities and efforts are being made to achieve greater energy efficiency compared with individual heating systems through regional heating and cooling businesses.

According to the Sixth Electricity Supply and Demand Basic Plan, which was announced by the MOTIE in February 2013, the government has strengthened measures to manage demand by companies, such as the demand adjustment programme of advance
notice (where financial incentives are offered to customers who reduce their demands at peak times by observing contract terms and conditions during the KEPCO-announced summer and winter peak periods) and load reduction by adjusting vacation or maintenance schedules, as well as using smart meters to manage the electricity-saving system and intelligent demand. Subsequently, in July 2015, the MOTIE released the Seventh Electricity Supply and Demand Basic Plan and announced that it would actively consider the temperature fluctuation and demand trends in developed countries for precise power-demand forecasting. For efficient supply and demand management, the MOTIE is adopting innovative technological solutions, including the negawatt market, ESS and energy management systems (EMS). Through these policy improvements, the MOTIE will be able to provide electricity without resorting to mandatory power-saving for industries or limiting air-conditioning temperatures, except in exceptional cases. The MOTIE announced at the plenary session of the National Assembly in July 2016 that it would release the Eighth Electricity Supply and Demand Basic Plan in July 2017. In the Eighth Electricity Supply and Demand Basic Plan released in December 2017, the government stated that it will gradually reduce its nuclear power plants and coal-power generation facilities; expand eco-friendly energy focusing on new and renewable energy; operate facilities that reduce coal-power generation and increase LNG-power generation, taking into consideration environmental costs; and increase the LNG facility capacity and generation capacity to achieve a stable power supply and environmental improvement. The MOTIE will announce the Ninth Electricity Supply and Demand Basic Plan this year with the aim of reducing fine dust by promoting the conversion of coal fuels to LNG.

## iii Technological developments

The fourth industrial revolution is revolutionising the energy sector among others, and the energy 4.0 era is emerging that fuses energy and related fields and promotes the digitisation of energy. Faced with this new development, the government will establish and implement plans to build an ICT-based energy infrastructure that effectively links distributed energy supply, flexible and intelligent consumer demand responses, and distributed grid. The second Smart Grid Basic Plan announced in July 2018 aims to foster the new Smart Grid industry by pursuing new projects to promote new services, establishing service experience facilities and expanding infrastructure and facilities. The government has decided to invest 400 billion won in the new projects.

In January 2019, the government announced the Roadmap for Promoting the Hydrogen Economy to assess the domestic and overseas hydrogen industry; to increase or expand the production capacity of hydrogen cars, hydrogen fuelling stations and fuel cells; and to build up an economical and stable hydrogen production and supply system, aiming to become a global hydrogen economy leader. The government is planning to expand the number of hydrogen fuelling stations, which are the core infrastructure necessary for the spread of hydrogen cars, from the current 14 to 310 in 2022 and 1,200 in 2040. In order to achieve this goal, the government is considering subsidies to support the installation and operation of hydrogen fuelling stations until hydrogen fuelling stations are economically viable. On 11 March 2019, the Hydrogen Energy Network (Hnet), a special purpose corporation in which 13 hydrogen-related companies including KOGAS and Hyundai Motor Company participate, was established with the goal of setting up and operating 100 hydrogen fuelling stations by 2022.
In the market, industries relating to smart factories or power plants, smart home appliances, eco-friendly energy towns, and zero-energy buildings are expected to grow. In particular, investment is expected to increase in connection with the construction of smart-grid and ‘internet of things’-dedicated infrastructure.

In addition, the new government’s policy initiative to promote green cars will expand the supply of green cars by building electric vehicle charging infrastructure, reducing the green car toll by 50 per cent and completing highway charging facilities. The policy initiative is expected to increase investment in green cars.

VI THE YEAR IN REVIEW

Key concepts in 2018 are the fourth industrial revolution, climate change, hydrogen economy and environment.

The government has revised the existing electricity supply-and-demand basic plan, which was established mainly for supply-and-demand stability and economic efficiency, by substantially enhancing environmental stability and safety. In order to cope with fine-dust pollution due to thermal power generation, the government has set up a coal-power generation reduction plan to abolish old coal power plants by 2022 and to convert coal fuels to LNG.

Furthermore, in order to gradually phase out nuclear power, the government has decided to abandon the construction project of six new nuclear power plants and to cancel the life extension of 10 old nuclear power plants. In order to avoid problems in energy supply and demand due to the phase-out of nuclear power, the government is supplementing measures to improve energy efficiency and manage demand.

With respect to climate change issues, Korea signed a universal climate deal, the Paris Agreement, adopted at the Paris climate conference (COP21) in December 2015 to replace the 1997 Kyoto Protocol on climate change. The National Assembly ratified the Paris Agreement in November 2016. Pursuant to the Paris Agreement, the government is obligated to cut greenhouse gas emissions by 37 per cent compared to its emissions forecast by 2030. In addition, in order to meet another goal of the Paris Agreement to limit the global average temperature to 1.5°C, the government should establish a carbon emission reduction target and a long-term low carbon development strategy by 2020. In that regard, the government held a cabinet meeting on 6 December 2017 and confirmed the First Basic Plan for Response to Climate Change, and the Basic Roadmap for 2030 National Greenhouse Gas Reduction, a detailed plan to achieve the 2030 greenhouse gas reduction target (37 per cent reduction in 2030 emission estimates) proposed by Korea in the Paris Agreement. In July 2018, the Korean government announced a revised Roadmap that reflected the energy conversion policy of the government. The target of the revised Roadmap is to reduce greenhouse gas emissions by 277 million tons in 2030, which constitutes a reduction of 58 million more tons compared to the previous Roadmap, by enhancing energy efficiency, strengthening the management of energy demand and fostering low-carbon industries.

In the process of implementing the Paris Agreement, there may be conflicts between existing market participants and government regulators. In order to mitigate such conflicts and to create new markets by establishing new energy regulations, the Moon Jae-in government aims to reduce greenhouse gas emissions by creating a wood industry complex through the expansion of forest investment, and invigorating forest carbon management and trading.

The new energy industry, which is strongly driven by the government, is expected to become the catalyst for the fourth industrial revolution. In particular, the emergence of ESS,
renewable energy, and ICT-convergence technologies are triggering a fundamental shift in traditional energy systems. On the other hand, there are concerns that the government may restrict the creative initiatives of market participants by limiting or micromanaging the roles of public and private enterprises in the new energy industry.

VII CONCLUSIONS AND OUTLOOK

The Fukushima nuclear power plant accident in Japan on 11 March 2011 and the large-scale power outage on 15 September 2011 in Korea have had a significant effect on Korea’s energy policies and laws. Because of the Fukushima nuclear accident, the likelihood is high that nuclear energy, which accounted for about 12 per cent of the country’s energy mix, will be reduced in the future and replaced with new and renewable energy. The power outage was the combined result of factors such as the failure to predict electricity demand, the price of electricity, which fell short of the production cost, and structural deficiencies in the industry, and this is likely to cause policy-oriented changes to the electricity industry, such as an increase in electricity rates.

As Korea signed the Paris Agreement, it is bound by obligations to reduce greenhouse gas emissions. These obligations are expected to produce further promotion of the sectors that develop and implement new, clean and renewable energy sources.
Chapter 16

LEBANON

Souraya Machnouk, Hachem El Housseini, Rana Kateb and Chadi Stephan

I OVERVIEW

Lebanon has been plagued by a chronic electricity crisis since the end of the 1975–1990 Civil War, with successive governments failing to make large investments to regain a sustainable position in the ailing sector and its outdated infrastructure. Most Lebanese regions experience 10 to 12 hours of electricity rationing a day, and these power cuts increase dramatically in the event of malfunctions in any of the aging plants. It is common for residents to pay additional costs for external generators to compensate for frequent power cuts. The electricity sector in Lebanon has long suffered from the lack of a global strategy aimed at revitalising it by addressing the needs with respect to infrastructure, generation capacity, operation and maintenance. The large influx of Syrian refugees over recent years has exacerbated the electricity crisis.

The energy sector in Lebanon is mostly controlled by the government and other public sector institutions, namely the state-owned Electricité Du Liban (EDL) founded in 1964. EDL is an autonomous public institution operating under the tutelage of the Ministry of Energy and Water (MOEW), and is vested with certain prerogative rights with respect to the transmission and distribution of electricity throughout Lebanon. Generation of electricity in Lebanon is mainly produced through thermal power plants constituting 80 per cent of the total generation capacity, while hydroelectric power plants provide around 10 per cent of such capacity. Also, and until 2010, additional electricity was purchased from neighbouring countries.

The year 2010 was a turning point for the electricity sector as it witnessed the approval by the Lebanese government of a Policy Paper for the Electricity Sector initiated by the MOEW (the Policy Paper). The Policy Paper comprised a comprehensive plan and a realistic implementation programme for the radical rehabilitation and development of the electricity sector to respond to the economic and social needs and aspirations of Lebanon. It covers three strategic areas: infrastructure, supply and demand, and legal framework. The electricity sector requires drastic reform of the wider energy sector. The Policy Paper addresses renewable energy and energy efficiency, Lebanon being one of the wealthiest countries in terms of renewable energy resources, notably, solar and wind. Accordingly, and with the support of the Lebanese Centre for Energy conservation (LCEC), the MOEW launched a number of tenders for solar and wind energy projects.

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1 Souraya Machnouk is a partner and Hachem El Housseini, Rana Kateb and Chadi Stephan are senior associates at Abou Jaoude & Associates Law Firm. The information in this chapter is correct as at May 2018.
While the MOEW initiatives and action plans provide for a series of solutions as part of a national energy strategy, the Lebanese electricity sector still requires long-term reform.

The first attempt to organise hydrocarbon resources in Lebanon in line with international standards occurred in August 2010, with the enactment of the Offshore Petroleum Resources Law (OPRL); this law established the Lebanese Petroleum Administration (LPA), which, together with the Lebanese Council of Ministers and the MOEW, participates in the regulation of the oil and gas sector.

In 2012, the Council of Ministers approved the launching of the first offshore licensing round for hydrocarbon exploration. In 2017, two long-awaited decrees were finally published in the Official Gazette, governing respectively:

- the delineation of the Lebanese maritime waters into 10 distinct blocs; and
- the tender protocol for the award of exploration and production agreements.

The first exploration and production agreements were signed on 9 February 2018 between the Lebanese government and a consortium of France’s Total, Italy’s Eni and Russia’s Novatek for bloc No. 4 and bloc No. 9.

Regarding onshore hydrocarbon resources, a draft law is still being discussed at the level of parliamentary commissions.

A draft hydrocarbon policy is currently being developed by the LPA, and will ultimately be subject to the approval of the Council of Ministers.

II REGULATION

The MOEW was established by virtue of Law No. 20 of 1966, and later reorganised by virtue of Law No. 247 of 2000, and is vested with the following powers, among others:

- Setting the general policy for the sector, as well as the general master plan, and the discussion of directive studies and putting them in their final version and submitting them to the Council of Ministers for ratification.\(^2\)
- Proposing the comprehensive rules for the organisation of the services related to the electrical energy production, transmission, distribution and the supervision of execution.\(^3\)
- Proposing draft laws and decrees related to the electricity sector.\(^4\)
- Proposing general safety conditions, environmental conditions and technical specifications applicable to the electrical installations and equipment, provided that the same are issued by virtue of a decree taken by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.\(^5\)
- Entering into the necessary contacts with other countries aimed at establishing electrical interconnections and exchanging electrical energy, and the ratification of the necessary contracts after the parliament’s approval.\(^6\)

\(^2\) Article 6 of Law No. 462 of 2002.
\(^3\) Article 6 of Law No. 462 of 2002.
\(^4\) Article 6 of Law No. 462 of 2002.
\(^5\) Article 6 of Law No. 462 of 2002.
\(^6\) Article 6 of Law No. 462 of 2002.
Taking all available measures, including the provision of distribution networks according to the laws and contracts ratified by the government to remedy any defects in any of the electricity sector’s activities that may have a negative effect on this sector’s interests or on the consumers’ rights and interests.\(^7\)

The OPRL vested various prerogatives related to hydrocarbon resources in the Council of Ministers, the MOEW and the LPA. Most of the decisions taken by the MOEW are subject to the approval of the Council of Ministers and such decisions are backed by the LPA’s technical advice and recommendations.

The Council of Ministers approves the state’s petroleum policy and all decrees related to petroleum activities. The Council of Ministers also approves all exploration and production agreements, appoints the LPA’s board, approves petroleum licences and decides on extending the duration of the exploration or production periods after consulting with the LPA.

The MOEW is responsible, \textit{inter alia}, for signing exploration and production agreements (following authorisation of the Council of Ministers), implementing the OPRL, supervising petroleum activities and protecting the environment from hydrocarbon-related pollution.

The LPA is an independent, technical, regulatory and advisory public entity in charge of regulating, managing and monitoring the petroleum sector, under the supervisory authority of the MOEW. The LPA’s prerogatives encompass the preparation of strategic, economic, financial, technical, geological and environmental plans so as to ensure a prudent and efficient management of Lebanon’s upcoming hydrocarbon wealth. The LPA’s goal is to ensure a successful, transparent and sustainable development process for all petroleum activities, in concert with various governmental bodies, international organisations and civil society.

The main laws and regulations governing hydrocarbons in Lebanon are:

\begin{enumerate}*[a] \item the OPRL dated 24 August 2010; 
\item Decree No. 9438 dated 4 December 2012, appointing the LPA; 
\item Law No. 163 dated 18 August 2011, identifying and delineating the marine zones of Lebanon; 
\item Decree No. 6433 dated 1 October 2011, governing and delineating the Lebanese Exclusive Economic Zone; 
\item Council of Minister Decision No. 41 dated 27 December 2012, opening the first offshore licensing round for hydrocarbon exploitation; 
\item Decree No. 9882 dated 16 February 2013, on the pre-qualification of companies; 
\item Decree No. 10289 dated 30 April 2013, providing for rules and regulations governing petroleum activities, as amended by Decree No. 1177 dated 31 July 2017; 
\item Decree No. 42 dated 19 January 2017, on the delineation of maritime blocs; 
\item Decree No. 43 dated 19 January 2017, approving the tender protocol for the award of exploration and production agreements and the model exploration and production agreement; 
\item Petroleum Tax Law No. 57 of 12 October 2017; and 
\end{enumerate}

\(^7\) Article 6 of Law No. 462 of 2002.
Council of Ministers’ Resolution No. 32 dated 14 December 2017, granting two petroleum licences over blocks 4 and 9 and mandating the MoEW to sign the corresponding exploration and production agreements, in accordance with the OPRL provisions.

ii Regulated activities

EDL is a public establishment with an industrial and commercial vocation. It was founded by Decree No. 16878 dated 10 July 1964, and is responsible for the generation, transmission, and distribution of electrical energy in Lebanon.8

Currently, EDL controls over 90 per cent of the Lebanese electricity sector (including the Kadisha concession in North Lebanon, which is owned by EDL), with a standing monopoly despite the enactment of Law No. 462 in September 2002 (Law 462) providing, *inter alia*, for the privatisation of electricity production and distribution activities. Some private companies hold a concession to generate or distribute electrical power. EDL’s capacity to generate electricity stands at approximately 1,800MW, leaving a gap with the actual market demand that is currently filled by unregulated private generators, mainly in residential and commercial sectors.

Other participants in the sector include hydroelectric power plants owned by the Litani River Authority, concessions for hydroelectric power plants such as Nahr Ibrahim and Al Bared, and distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

In order to ensure equality and competition, Law No. 462 provides that licences and permits are granted to those who satisfy the prerequisite conditions specified by the National Regulator for the Electricity Sector Organisation (NRESO), an establishment affiliated to the MOEW. Preferential treatment and imposing uncodified restrictions on the provision of services is explicitly prohibited by Law No. 462.

Although Law No. 462 entered into force in 2002, the privatisation process and the formation of the NRESO are not yet implemented for various reasons, mostly political.9 The long-awaited Law No. 48 regulating public-private partnerships (the PPP Law) was enacted on 7 September 2017. Such Law applies to government and municipality projects such as infrastructure projects, and also to electricity production and distribution projects.

The licence is an official document issued by the NRESO to joint-stock companies that are granted a concession for a maximum duration of 50 years to (1) establish, equip, develop, appropriate, operate, manage or market equipment within the scope of public services in the fields of production, transportation and distribution of power exceeding 10MW, or (2) use the aforementioned equipment by virtue of a financing leasing contract.10 Since the NRESO has not been established yet, the Lebanese Parliament enacted several laws granting the authority to the Council of Ministers to issue the licences and permits for a specific period of time until the establishment of the NRESO.

The OPRL subjects the performance of ‘petroleum activities’ to a licence; the term ‘petroleum activities’ encompasses planning, preparation, installation and implementation of activities associated with a subsea reservoir, such as reconnaissance, exploration, production and exploitation, laying of pipelines, development of facilities, production and transportation. The OPRL singles out the following licences:

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8 Article 1 of Decree No. 16878 of 1964.
9 Article 19 of Law No. 462 of 2002.
10 Article 1 of Law No. 462 of 2002.
Reconnaissance licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This non-exclusive licence is granted by virtue of a MOEW resolution, based on the opinion of the LPA, for a period not exceeding three years.

Construction, placement and operation of transportation or storage facilities: the Council of Ministers may grant such a licence if the corresponding works are required as part of the approved plan for development and production.

Production licence: The general conditions and scope of this licence and the corresponding fees are determined by the Council of Ministers by decree upon the proposal of the MOEW based on the opinion of the LPA. This licence is granted by virtue of a MOEW resolution based on the opinion of the LPA.

The OPRL also provides that the Council of Ministers awards exclusive authorisations to carry out petroleum activities in a specific bloc by virtue of an exploration and production agreement, setting out the right-holders’ authority to explore, develop and produce oil and gas offshore.\textsuperscript{11}

iii Ownership and market access restrictions

There are no major ownership and market access restrictions in the energy sector. However, it should be noted that there is a market monopoly by EDL, which controls approximately 90 per cent of the electricity generating capacity in Lebanon, save for the few above-mentioned concessions.

Lebanon recently witnessed instances where private sector companies were granted the right to generate electricity. Most notably, two power ships owned by a Turkish private company have been leased by the Lebanese government since 2013 in order to compensate for the shortage in the electric supply resulting from the lack of proper maintenance of existing plants. The two power barges are anchored at a specially constructed dock off the coast of Beirut, and have a total output of 370MW, with an output to the national grid of an extra two hours’ electricity a day.

The transmission of electrical energy remains exclusive to EDL, but it is possible, through a decree taken by the Council of Ministers upon the proposal of the Minister of Energy and Water, to ratify contracts with the private sector for the management, operation, development or equipment of the transmission’s activities.

The OPRL and Decree No. 43 of 19 January 2017 regulate the terms of exploration and production agreements to be entered into between the Lebanese state and a consortium of at least three right holders. The various right holders form an unincorporated joint venture in which each of them has an indivisible interest. However, the OPRL and Decree No. 43 unequivocally provide that the Republic of Lebanon has title to all petroleum resources in the seabed of Lebanese waters and the exclusive right to their management.

There are no specific restrictions on the award of licences pursuant to the OPRL, except for qualification requirements with which any prospected licensee is required to comply.

\textsuperscript{11} As per the specific provisions of the draft EPA enacted by virtue of Decree No. 43 dated 19 January 2017.
Transfers of control and assignments

Licensees and permit holders are not allowed to waive or assign their participating interest or permits to any other party, unless they have obtained the prior approval of the NRESO’s (currently the Council of Ministers) and provided that the transfer or assignment conforms with Law No. 462 and the regulations issued for its implementation.\(^{12}\)

The OPRL provides that the interest of a right holder in an exploration and production agreement is a ‘non-transferable participation interest’. The OPRL further provides that:\(^{13}\)

\(a\) the rights and obligations pertaining to a petroleum right may not be transferred or assigned in whole or in part except to a company qualified according to the provisions of the OPRL, and only after obtaining the approval of the Council of Ministers;

\(b\) the same shall apply to the direct assignment of any right in a company that enjoys a petroleum right, including, \textit{inter alia}, the transfer of shares or other rights that may grant the holder thereof decisive control over said company; and

\(c\) no ownership or usage right in any facility upon which a petroleum activity depends shall be transferred, except after approval by the Council of Ministers.

Finally, the OPRL\(^{14}\) provides that the conditions for the sale or transfer of any interest in petroleum shall be set out in a Decree taken by the Council of Ministers.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

Vertical integration and unbundling

As stated above, the Lebanese electricity sector is monopolised by EDL, who currently controls over 90 per cent of the sector (including the Kadisha concession in North Lebanon). Moreover, the sector includes hydroelectric power plants owned by the Litani River Authority; concessions for hydroelectric power plants such as Nahr Ibrahim and Al Bared; and distribution concessions in Zahle, Jbeil, Aley, and Bhamdoun, each of which serves a particular geographical area.

According to the 2010 Policy Paper for the Electricity Sector, this structure should be subject to several changes that are aimed at a partial liberalisation of the electricity sector in Lebanon. After the Paper was announced, investors became interested in the electricity sector, and in engaging in the production and distribution of electricity according to the regulations in force. An important focal point is the collaboration between the public and private sectors since 2012, which consists in outsourcing to private sector companies some of EDL’s activities related to the design, implementation, operation and maintenance of a distribution network with the customers and metering services. This is encouraging for the private investors to invest increasingly in the Lebanese electricity sector.

In relation to natural gas, there is no market regulation yet; the only relevant instrument issued so far is Law No. 549 dated 20 November 2003 governing the design, financing,

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\(^{12}\) Article 23 of Law No. 462 of 2002.

\(^{13}\) Article 70 of the OPRL entitled ‘Transfer or Assignment of a Petroleum Right’.

\(^{14}\) Article 40 of the OPRL entitled ‘Sale of Petroleum’.
development and reconstruction of two refineries; building a terminal for the import and export of LNG; building facilities for the storage of LNG; and establishing networks for its sale and distribution.

Currently, no LNG terminals or facilities have been erected. Accordingly, there is no effective market for LNG sale or distribution.

ii Transmission/transportation and distribution access
As stated above, the transmission of electrical energy remains under EDL’s monopoly and it is possible, by a decree of the Council of Ministers upon the Minister of Energy and Water’s proposal, to ratify contracts with the private sector for the management, operation, development or equipment of the transmission’s activities. The ‘private sector’ includes any privatised company or any company owned by the private sector.15

In relation to natural gas, these issues have not been addressed yet.

iii Rates
The rates of the distribution and sale of electricity for all voltage levels are set by EDL according to its investment and financing needs in order to develop its activity.16

In relation to natural gas, these issues have not been addressed yet.

iv Security and technology restrictions
The MOEW is entitled to take any measures, including those aimed at ensuring that the distributions are executed according to the laws and contracts ratified by the government, in order to remedy any defects in the electricity sector’s activities that may negatively impact this sector’s interests or on the consumers’ rights and interests. The MOEW may also propose general safety conditions, environmental conditions and technical specifications with respect to electrical installations and equipment, provided that they are issued by virtue of a decree taken by the Council of Ministers upon the competent minister’s proposal after consulting the competent authorities.17

Similar considerations to those outlined above govern petroleum activities. Chapter 9 of the OPRL, entitled ‘Health, Safety and the Environment’, outlines the safety and security obligations imposed in conjunction with petroleum activities. These include ensuring the highest levels of safety, having in place a ‘health, safety and emergency response plan’ and efficient emergency preparedness. The competent authorities also have the right to request that the right holder place a determined facility at their disposal and facilitate any specific measures for the purpose of protecting health, safety, security or the environment.

In addition, it should be noted that the Israel Boycott Act enacted by the Lebanese parliament on 23 June 1955 prohibits, under penalty of criminal sanctions, any natural or moral person from conducting, directly or through an intermediary, any agreement with or in the interest of bodies or persons residing in Israel.

15 Article 5 of Law No. 462 of 2002.
16 Article 8 of Decree No. 16878 of 1964.
17 Article 6 of Law No. 462 of 2002.
The Council of Ministers may, pursuant to a recommendation of the Boycott Bureau (a stand-alone body operating at the Lebanese Ministry of Economy and Trade), enlist any company breaching the provisions of the Israel Boycott Act on a blacklist and prohibit any dealings with such company.

IV ENERGY MARKETS

i Development of energy markets

Law No. 462 was expected to liberalise the sale and distribution of electricity in Lebanon and create a competitive free market for electricity. The NRESO, that was supposed to play a leading role in regulating the electricity sector, has not been established yet. The Policy Paper for the Electricity Sector provides for (1) the implementation of a programme to cover the traditional power supply infrastructure whereby international private companies have carried out the rehabilitation of existing power plants and construction of new plants, and (2) a promising renewable energy programme under which qualified developers will build and operate solar or wind power stations and sell the power generated to EDL, which retains the exclusive right of transporting the electricity to end users. However, until Law No. 462 is fully implemented, the supply and sale of energy remains primarily controlled by EDL. Some flexibility has been witnessed on that front since the management of EDL’s distribution business was handed over to three distribution service providers under service contracts. Further, the sale prices of sources of energy are fixed by the state, and investors can engage in the production of electricity subject to applicable regulations using the tariffs and fees mandated by EDL.

In relation to natural gas, no markets have been developed or regulated yet.

ii Energy market rules and regulation

With regard to electricity, EDL is solely entitled to transmit and distribute electricity to end users in Lebanon. However, and as stated above, other parties play a partial role in the sector, such as the concessions for hydroelectric power plants of Nahr Ibrahim and Al Bared and the distribution concessions in Zahle, Jbeil, Aley and Bhamdoun.

It is important to mention that, up until the full liberalisation of the electricity sector in Lebanon, the tariffs and rates are set by EDL even for the above-mentioned concessions. As for any electricity production activities carried out by the private sector, the transmission of such produced electricity remains the sole right of EDL.

In relation to natural gas, no markets have been developed or regulated yet.

iii Contracts for sale of energy

Electricity producers and distributors are permitted to have individual contracts for the sale of electric power to EDL, since the latter possesses the sole right to transmit the electricity. Hence, electricity producers are required to connect their production to EDL’s grid in order for it to reach the end users, while the rates and other charges are mandated by the government.

In relation to natural gas, the corresponding guidelines are yet to be developed.
iv Market developments

The full implementation of Law No. 462 would be considered a huge step forward in the liberalisation and encouragement of private investments in the energy sector. However, this law presents some flaws pertaining to the tendering process for the operation and management by independent power producers (IPPs) of existing power plants, as a prelude to the IPPs entering into power purchase agreements with the Lebanese government.

The PPP Law will undoubtedly create new prospects for the implementation of power projects in Lebanon. The PPP Law introduces a new legal regime, replacing the traditional procurement processes, which suffered from weak transparency, competitiveness and accountability standards. The PPP Law renames and grants the High Council for Privatization and PPP the authority to evaluate potential PPP projects. The PPP Law stipulates the main mandatory provisions that must be included in the PPP agreement.

The Sustainable Oil and Gas Development in Lebanon project is being developed as part of the United Nations Development Programme (UNDP). One of the programme’s components is titled ‘Enabling Environment for the Use of Alternative Fuels in the Energy and Transport Sectors’, and provides for the conducting of cost-benefit analyses for the introduction of natural gas and other low carbon fuels in the energy and transport sectors. These should act as a precursor for the development of the corresponding legislation, including without limitation in relation to market development.

In December 2017, the Council of Ministers awarded exclusive licences to a consortium of three companies (Total, Eni and Novatek) for the exploration and production of petroleum offshore, in the Lebanese Exclusive Economic Zone.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

There is an obvious trend to increase the inclusion of the production of renewable energy as part of the implementation of the national electricity strategy. The MOEW encourages public, private and individual initiatives to adopt the utilisation of renewable energies to reach the 12 per cent target in the generation of electricity by 2020. In an initiative launched in partnership with the MOEW, the UNDP established the Country Energy Efficiency and Renewable Energy Demonstration Project for the Recovery of Lebanon (CEDRO) in 2007, with an initial budget funded by the government of Spain to enhance the national energy strategy by contributing in achieving renewable energy projects.

Also, the LCEC works closely with the MOEW by setting action plans and national strategies in terms of energy efficiency and renewable energy. In an effort to reach the 12 per cent objective, the LCEC has set two consecutive four-year action plans, known overall as the National Energy Efficiency Action Plan (NEEAP). The 2011–2015 NEEAP comprises 14 initiatives of which seven were dedicated to renewable energy. The 2016–2020 NEEAP includes 26 initiatives, setting targets and strategies for the achievement of the energy-saving

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18 The Lebanese Center for Energy Conservation (LCEC) is an independent governmental organisation operating under the supervision of the Lebanese Ministry of Energy and Water.
19 The National Energy Efficiency Action Plan is a national action plan developed based on the requirements of the League of the Arab States and according to the format used by the European Union.
targets. The LCEC, with support from the MOEW, has further put in place the National Renewable Energy Plan (NREAP) 2016–2020, a follow-up report to the 2011–2015 NEEAP specifically dedicated to renewable energy strategies and their implementation.

Lebanon has already witnessed the implementation of projects using renewable sources that are connected to the grid via EDL:

a Wind energy: Lebanon constitutes a viable country for energy wind production. In 2013, as part of the implementation of the national strategy for renewable energy development leading to achieving the 500MW wind generation target by 2020, the MOEW launched a tender to private corporations to build the first wind power farm in Lebanon with a capacity of 50–100MW. Under its first power purchase agreement, signed on 1 February 2018, the Lebanese government agreed to purchase 200MW in total from three Lebanese companies. In March 2018, the MOEW launched a second bid round to build additional wind farms for a total capacity of 200–400MW. The electricity generated by the wind farm will be sold to EDL via offtake agreements.

b Solar energy: a first of its kind on a national level, the Beirut River Solar Snake, consisting of a photovoltaic (PV) farm, with a total planned output of 10MW, comes as part of the NEEAP to install 200MW of solar farms by 2020. The first phase of the project has been achieved, connecting an extra 1MW of electricity to the grid. Also, the MOEW plans to install around 30MW of solar farms for the public sector between 2016 and 2020. In 2017 and 2018, the Moew launched two consecutive bids for 12 and 24 PV farms respectively (of 10–15MW each). Recently, a new bid has been launched for three PV farms (of 70–100MW each) to include for the first time electricity storage of 70 mw/70mwh. The development of PV farms is becoming more appealing, especially with the decrease in related solar installations’ prices, the decentralisation of PV farms and the growing involvement of the private sector.

c Water energy: while 75 per cent of Lebanon’s market demand was covered by electricity generated from hydroelectric sources in the 1970s, the production of hydroelectric power was seriously affected during the civil war and afterwards. Opportunities in the hydropower sector are numerous, as the General Directorate of Hydraulic and Electric Resources at the MOEW envisages a promising strategy encompassing rehabilitation of the existing hydropower plants, the development of dams and the construction of new hydroelectric plants and micro hydropower systems. The current hydropower installed capacity is approximately 221MW, the main plant being the Litani station located in the Bekaa Valley. Also, as part of the NREAP 2016–2020 action plan, the MOEW launched the implementation of the Janna dam, which will include the hydroelectric power plant supplying the grid with approximately 100MW of hydroelectricity. In 2018, the MOEW launched a bid for hydroelectric power plants based on studies carried out by leading European engineering firms, aimed at identifying potential sites for such projects. It is expected that hydroelectric sources will generate approximately 300MW by 2020.

d Bioenergy (including waste to energy): 23 bioenergy streams have been identified as potential resources for energy production. All action plans stated in the National Bioenergy Strategy for Lebanon set in 2012 by the MOEW along with the UNDP as part of the CEDRO project have been reinstated in the NREAP 2016–2020, as the

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20 The construction of the 300-foot high Janna Dam was suspended in May 2016, only to resume later despite local ecological and environmental warnings and concerns.
Ministry recognises that the future of bioenergy is promising. On-ground surveys and assessments have been carried out to identify the most efficient and promising biomass streams. As for waste to energy, the process for producing electricity was launched in 2015 through the establishment of a 7MW plant in the Naameh landfill to produce electricity.

ii Technological developments

The LCEC has drafted an energy conservation law, the Renewable Energy and Energy Conservation Law, which sets the legal framework for the implementation of the NREAP and addresses the production by the private sector of electricity from renewable energies, the management of energy supply and demand and the computation of renewable energy tariffs. The proposed law also covers topics related to energy efficiency in connection with the electricity grid. It provides for mandatory audits and certifications while catering for incentives to promote green solutions.

Notwithstanding the above, a series of initiatives are being carried out with respect to the development of smart technologies that would have an estimated impact on energy demand management. The launching by EDL of the advanced metering infrastructure, comprising the installation by three private distribution service providers of smart meters over the Lebanese territory, is expected to provide energy efficiency in terms of monitoring and synchronisation of wide area networks. A pilot project is currently being carried out to test the responsiveness of the Lebanese network.

VI THE YEAR IN REVIEW

There is a growing national momentum to develop action plans and strategies for the electricity sector, and to encourage all related initiatives. The political commitment in a country like Lebanon plays a crucial role in achieving the goals of the 2016–2020 NREAP. The involvement of the private sector in the various tenders relating to energy and electricity projects is increasing, especially in light of the incentives proposed by the Central Bank of Lebanon and private financial institutions to finance such projects.

A 10-year reform plan proposed by the incumbent Minister of Energy and Water based on the 2010 Policy Paper was approved by the Council of Ministers on 28 March 2017. The first phase of the plan involves the lease of two additional power barges from the Turkish company that already operates two smaller ships in Lebanon, and the activation of the two recently overhauled power plants of Zouk Mikael and Jiyyeh, with the aim of increasing electricity supply to 21 hours a day this year. The main idea behind the leasing of the barges is to give the MOEW more time to build new power plants that can provide all of Lebanon with 24 hours of electricity in the future. The two additional floating power plants will reportedly generate up to 890MW at a cost of US$340 million a year. The plan also envisions the construction of solar power plants and hydroelectric power plants in several areas of the country.

The plan has been met with scepticism and controversy, with challengers alleging its high-cost factor, lack of transparency and the expectancy that it will result in a significant increase in electricity tariffs.

The issuance in early 2017 of the decree on the delineation of maritime blocs and the decree on the tender protocol and the model exploration and production agreement has paved the way for the closing of the prequalification process; the grouping of the qualified
companies in consortia; and, finally, following approval by the Council of Ministers, the execution of the corresponding exploration and production agreement between the winning consortia and the Lebanese state for one or more of the maritime blocs.

On 26 January 2017, the MOEW announced that five out of the 10 maritime blocks were open for bids. Prequalified companies should submit their bids by 15 September 2017. The aim of the Lebanese government is to have one or more exploration and production agreement signed by the end of 2017.

VII CONCLUSIONS AND OUTLOOK

While the Lebanese energy and electricity sector is currently witnessing drastic progress, it is essential to ensure a full correlation between the development of the legal framework and the privatisation process set out by the PPP Law and Law 462. The restrictions imposed by Law 462 should be lifted so as to offer a more flexible legal framework, allowing the private sector to invest in energy production and distribution at fair yet competitive rates to third parties. Additionally, the introduction of legal reforms for alternative technologies and renewable energy activities should be envisaged to fill a considerable gap towards a sustainable national energy strategy.

After a long stalemate (between 2013 and 2017), Lebanon is steadily heading towards becoming a hydrocarbon state, provided extractable discoveries are made in the near future. A successful first licensing round will be a decisive step.

Lebanon’s key challenge is to ensure that the process is managed with a sound governance system and utmost transparency. The Lebanese government’s recent request to join the Extractive Industries Transparency Initiative is a key indicator in this direction, and a message of confidence to both the applicant companies and the Lebanese civil society.
I OVERVIEW

The Myanmar energy market started legal reform in 2011, at a time when the country opened up to foreign investment after decades of isolation. The recent optimism in Myanmar’s economy is largely attributed to its abundant untapped resources, particularly oil, hydropower and natural gas. Presently, Myanmar’s energy sector accounts for more than half of its export earnings and foreign direct investment.

In terms of the National Electrification Plan for Myanmar, the Ministry of Electricity and Energy (MOEE), intends to extend electricity access to the entire population by 2030. In the meantime, benchmarks are set for 2021 aiming for the provision of electricity to 55 per cent of Myanmar’s population, while increasing the number to 75 per cent in 2026. We understand that the MOEE has been working towards arranging for international funding, as well as allocating national budget for implementation of the objectives for electrification.

According to the MOEE recent annual progress of electricity implementation amounts to 15–19 per cent, which shows the government is pushing for development in the industry. The national grid currently produces 3448MW, 2400MW of which is produced by hydropower plants and 1038MW by thermal power industries. According to the Asian Development Bank (ADB) Myanmar has an abundance of hydropower – in excess of 100,000MW – so the government’s focus is naturally on upgrading and developing those plants.

The MOEE’s announcement involving the National Electrification Plan is a great positive development for Myanmar citizens and both local and foreign sponsors, as poor infrastructure is currently impeding the economic development of Myanmar. Currently, only 35 per cent of the entire population of Myanmar is connected to the electricity grid compared to a world average of almost 88 per cent; and the average annual per capita electricity consumption is 217kWh (8 per cent of the world average). Strengthening Myanmar’s energy sector is crucial to reducing poverty and enhancing development prospects for the country. Social and economic progress in Myanmar depends on electrification, without which health, education and other key services will continue to suffer.

Other initiatives to bolster electricity efforts includes bilateral cooperation with neighbouring countries. In January 2018, Myanmar and Laos signed a memorandum of understanding on power cooperation. Similarly, in March 2018, Myanmar, China and Bangladesh signed an agreement on trilateral power trade. Further, under the Myanmar

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1 Krishna Ramachandra is managing director and Priyank Srivastava is special counsel at Duane Morris & Selvam LLP.
Sustainable Development Plan (MSDP) 2018–2030, containing a long-term vision for Myanmar, the country aims to develop reliable national energy statistics by 2020 that will help the government to estimate the volume of electricity required demographically.

A new government came into power on 1 April 2016, led by the National League for Democracy (NLD). The NLD is headed by Daw Aung San Suu Kyi. She currently holds the newly created position of State Counsellor. The Presidency is currently held by U Win Myint.

Prior to the end of the USDP’s reign over Myanmar (between December 2015 and January 2016), over 35 new laws were passed by the USDP. These new laws include the new Arbitration Law enacted on 5 January 2016 (the 2016 Arbitration Act) that provides a domestic legal framework to fully implement and comply with the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958 (the New York Convention), which Myanmar signed and ratified in 2013.

**Sanctions and key considerations**

There are at present no sanctions in force against Myanmar (save for arms embargoes and penalties against certain military units and officials based on human rights abuses resulting from the Rohingya crisis) from the European Union, United Kingdom or Australia. On 7 October 2016, US President Obama issued an Executive Order (EO) on the Termination of Emergency with Respect to the Actions and Policies of the Government of Burma (the October EO), thereby terminating the national emergency declared in EO13047 of 20 May 1997 with respect to Myanmar and revoking the EOs previously issued to sanction Myanmar.

Notably, the October EO:

- lifts the import ban on rubies and jadeites of Myanmar origin into the United States;
- lifts immigration restrictions on specified Myanmar nationals and removes all individuals from the Specially Designated Nationals List. However, this will not affect Myanmar nationals who are subject to separate sanction regimes (e.g., counter-narcotics sanctions);
- terminates all Office of Foreign Assets Control restrictions on banking with Myanmar. This includes a suspension of a prohibition by the Financial Crimes Enforcement Network (FinCEN) against US financial institutions maintaining correspondent accounts for Myanmar banks. However, it should be noted that the suspension is contingent on Myanmar’s progress in addressing money laundering, corruption and narcotics-related activities. FinCEN will remove the prohibition entirely when Myanmar has made sufficient progress on this front; and
- removes the requirement to comply with the State Department Responsible Investing Reporting Requirements. This is now voluntary.

**GOVERNMENT FRAMEWORK AND REGULATIONS**

**Governmental divisions**

Under the state-owned Economic Enterprises Law of 1989 (the SOE Law), the Union Government has the sole right to carry out power generating services and is also empowered to grant exemptions. With the consolidation of the new MOEE, Myanmar’s power sector remains regulated by a state-owned buyer model, with two key offtaking government entities, detailed below.
the Electric Power Generation Enterprise (EPGE) (formerly the Myanmar Electric Power Enterprise (MEPE) alongside the Department of Electric Power (DEP)). EPGE operates and plans the Myanmar National Grid System, buys electricity from both public and private producers and then sells the electricity on to the Electric Supply Enterprise and Yangon City Electricity Supply Board. The Yangon Electricity Supply Board and other regional and state electricity supply boards assist the EPGE in the purchase and distribution of power.

b The Hydropower Generation Enterprise (HPGE) alongside the Department of Hydropower Planning and the Department of Hydropower Implementation. The HPGE operates and maintains large-scale hydroelectric facilities for the public sector.

ii Legal history of the MOEE
The legal history of the MOEE from 1951 to 2018 is as follows:

a in 1951, the Electricity Supply Board (ESB) was formed under the then Electricity Act of 1948. The ESB was under the then Ministry of Industry and Handicraft;

b in 1972, the ESB was changed into the Electric Power Corporation (EPC);

c in 1975, the then Ministry of Industry and Handicraft was reorganised into the Ministry of Industry No. 1 and Ministry of Industry No. 2. The EPC was under the control of the then Ministry of Industry No. 2;

d in 1985, the then Ministry of Industry No. 2 was extended and reorganised into the Ministry of Industry No. 2 and the Ministry of Energy. The EPC was under the umbrella of the Ministry of Energy;

e on 1 April 1989, the EPC was renamed the MEPE;

f in 1997, the Ministry of Energy was extended and reorganised into the Ministry of Energy and the Ministry of Electric Power. The MEPE was under the control of the Ministry of Electric Power;

g in 2006, the Ministry of Electric Power was reorganised into the Ministry of Electric Power No. 1 and the Ministry of Electric Power No. 2. The MEPE was under the direct control of the Ministry of Electric Power No. 2;

h in 2012, the Ministry of Electric Power No. 1 and the Ministry of Electric Power No. 2 were merged to form the MOEE pursuant to Notification No. 63/2012;

i in March 2016, the MOE and MOEP were consolidated into the new MOEE; and

j in March 2016, following the reorganisation of the Union Government’s ministries and departments, the MEPE was reformed as the EPGE.

In addition to the role of MOEE on power projects, there are a number of other government institutions that are important from the perspective of a foreign investor intending to proceed with a power project in Myanmar. We have categorised the related government authorities in terms of their relevance at various phases for a power project.

III LEGAL SYSTEM
The legal system in Myanmar is based on English common law. Myanmar legislation includes 13 volumes of codified laws enacted from 1841 to 1954 and published in the Burma Code, as well as various other laws, notifications, rules and regulations passed from time to time.
However, the current legal framework poses significant challenges for foreign investors as some laws remain outdated while new laws remain untested in the courts, providing little case law and guidance to both investors and lawyers on the ground.

The relevant laws governing Myanmar’s power sector include:

a. the Arbitration Law 2016;
b. the Contract Act 1872;
c. the Environmental Conservation Law 2012;
d. the Foreign Investment Law 2016;
e. the Farmland Law 2012;
f. the Income Tax Law (ITL), as amended up to 2016;
g. the Union Tax Law, amended annually;
h. the Myanmar Companies Law 2017 (MCL);
i. the Myanmar Constitution 2008;
j. the Myanmar National Committee on Large Dams Law 2015;
k. the Petroleum and Petroleum Products Law 2017 (PPPL);
l. Presidential Notification 1/2013;
m. Presidential Notification 1/2017;
n. the Public Debt Management Law 2016;
o. the Registration of Deeds Law 2018;
p. the Stamp Act 1891 (and the Amendment of the Stamp Duty Act 2017);
q. the State-Owned Economic Enterprises Law of 1989 (the SOE Law, and the Amendment of the SOE Law 1997);
r. the Environmental Conservation Law of 2012;
s. the Environmental Conservation Rules, published in June 2014;
t. the Electricity Law of 2014;
u. the Myanmar Investment Law of 2016 (MIL);
v. the Transfer of Immovable Property Restriction Law 1987;
w. the Transfer of Property Act of 1882;
x. the Vacant, Fallow and Virgin Lands Management Law 2012 (and the Vacant, Fellow and Virgin Lands Management Law Amendment 2018);
y. the Industrial Design Law 2019; and
z. the Trademark Law 2019 (effective date yet to be announced).

The above laws are not an exhaustive list of all relevant legislation. Additional local legislation, regulations and customary practice may be relevant depending on the source fuel, project location and project complexity.

IV PROCUREMENT

The government understands the need for facilitating transparent procurement processes in order to instil confidence both domestically and internationally to the business community and, of equal importance, to attract local and foreign investment in support of the government’s rapid energy reform initiatives.

Since 2013, via Presidential Directive No. 1/2013 titled Regulations to be abided by when issuing tenders for investment and economic activities (the Tender Directive), government departments and ministries are required to hold public tenders for goods, major works, and services that they may require. The Tender Directive is the only guiding authority...
in Myanmar on procurement, and is often criticised because it is not actual law but only a Directive. Generally speaking, at present the Tender Directive in Myanmar is local and does not follow international standards.

The Tender Directive, while lacking substance, sets out the procedure to be followed by government departments, ministries, and state-owned enterprises, including the establishment of procurement or tendering committees, open invitation to tender, and public announcement of tenders. On 10 April 2017, the Union Government issued new Notification No. 1/2017 introducing a new tender procedure (the Tender Procedure) in order to ‘eliminate waste of the State’s fund, corruption and monopolizing tender’ and to ‘ensure just and fair competition, transparency, accountability and responsibility.’ The Tender Procedure provides the threshold for launching a tender for construction or procurement of goods and services valued at 10 million kyat. Importantly, irrespective of the fact that the participation eligibility for foreigners is not clear, foreign companies without any presence in Myanmar may participate in the tender subject to the absolute discretion of the relevant department. In the event of a bid award to a foreign company, a subsidiary is required for the purpose of execution of contract with the relevant government department.

Currently, Myanmar has no specific PPP laws, guidelines or regulatory framework dealing with the procurement of large-scale power projects or PPP projects. Pursuant to the Tender Procedure, specific tender procedures for PPP projects may vary depending on the nature of the bid. The MIL provides a basic framework for private foreign investors to obtain an investment permit and project approval. However, the MIL does not deal with tendering- and procurement-related issues in any detail.

Any investor seeking to develop a self-proposed project will face difficulty, as this is uncommon in Myanmar.

V FOREIGN INVESTMENT IN MYANMAR’S ENERGY SECTOR

i Myanmar investment commission permit

A foreign sponsor must obtain a Myanmar investment commission permit (an MIC permit, or investment licence) to develop a power plant (i.e., to carry out business activity) in Myanmar and obtain project consent. Apart from providing for project consent, an MIC permit allows a foreign investor to benefit from certain investment incentives available under the MIL. Key incentives include:

a investment protection. The MIL guarantees that a company operating with an MIC permit under the MIL will not be nationalised during the permitted investment period. There is also a further guarantee that investments with an MIC permit will not be terminated before the expiry of the term of the MIC permit without sufficient cause; and

b tax incentives. Income tax holidays are potentially available for foreign sponsors for periods of three, five or seven years, subject to MIC discretion and what zone the project is located in. Zone 1 includes the least developed areas of Myanmar excluding Yangon and Nay Pyi Taw; Zone 2 (moderate) includes more developed zones, but still excludes Yangon and includes Nay Pyi Taw; and Zone 3 (developed zones) includes Yangon and Mandalay. The income tax holidays are inclusive of the year the project company begins operations.
The MIC permit may also grant one or more of the following exemptions and reliefs to any project company:

- **a** exemption of internal taxes on imported raw materials within the first three to seven years of commercial production;
- **b** exemption or relief from income tax on profits of the business kept in reserve funds and reinvested in the business within one year after the reserve is made;
- **c** right to deduct accelerated depreciation from the profit concerning machinery, equipment, building or other capital assets used in the business at rates set by Myanmar;
- **d** relief from tax on up to 50 per cent of the profits accrued from the export of goods produced in Myanmar;
- **e** right to pay foreign employees' income tax at the rates applicable to citizens residing within the country;
- **f** rights to deduct from assessable income the expenses incurred with respect to necessary research and development carried out within Myanmar;
- **g** exemption or relief from customs duty or other domestic taxes on imported machines and other equipment used during the period of construction of the business; and
- **h** exemption or relief from commercial tax on any goods produced for export.

**Right to transfer foreign currencies**

A foreign sponsor has the right to transfer abroad the types of foreign currencies set out below:

- **a** the amount of foreign currency brought into Myanmar as foreign capital; and
- **b** the net profit after deducting all taxes and reserve funds by the party who brought in the foreign capital.

Foreign currency permitted for withdrawal includes the value of assets on the winding-up of a business, subject to MIC approval.

A foreign employee can transfer his or her salary and lawful income after deducting taxes and other living expenses incurred domestically.

**ii  MIC endorsement**

A foreign sponsor intending to make a small-scale power investment (having investment capital of less than US$5 million) who desires a long-term lease right for a period exceeding one year must apply for an endorsement at a MIC regional office. If the investor's investment capital exceeds US$5 million he or she must apply for an endorsement at the MIC head office.

It is not industry practice in Myanmar, nor is it recommended, for a foreign sponsor to only obtain an endorsement to develop a power plant. Rather, the tried and tested approach is that a foreign investor will obtain both an endorsement to secure long-term lease rights and an MIC permit to carry out the desired business activity. We would recommend that any sponsor intending to develop a power plant in Myanmar obtain an MIC permit.

**Right to enter into a long-term lease**

A foreign-owned company (i.e., sponsor) without an endorsement (as specified below) or MIC permit or is only allowed to enter into a lease agreement not exceeding one year.
With an MIC permit or endorsement (as specified below), a foreign sponsor may be permitted to lease or use land for an initial period of up to 50 years, which may be extended for two further periods of 10 years each.

### iii Processing time

The MIC permit is granted on a case-by-case basis depending on the size of the power project. At a minimum, a sponsor should expect to wait at least six months to obtain an MIC permit. Coincidently, the period to obtain an endorsement is also the same, although this was not the intent of the legislature.

Tenders are issued through the MOEE, and investors and sponsors can visit the MOEE website\(^2\) for up-to-date information on independent power producer (IPP) tenders.

### VI BANKABLE PROJECT DOCUMENTS

Arguably, the project documents (e.g., memorandum of agreement, power purchase agreement, build-operate-transfer agreement, EPC contracts, land lease agreement, security documents, fuel supply agreement) used for the Myingyan IPP Deal should be adopted as good practice for other IPP projects in Myanmar going forward. This is critical for foreign sponsors because, before the Myingyan IPP Deal, a power deal of this magnitude had never been seen before.

If the energy deal is funded by way of project finance, the main challenge for foreign sponsors will be ensuring the documentation structure remains within the framework for limited recourse project financing. Sponsors need to consider in advance the requirements for having in place bankable collaterals for meeting the lenders’ requirements for the project. We have also witnessed that foreign lenders usually push hard to enhance the recourse options by establishing liens on the interests or assets of the sponsors and shareholders of any project company. If the financing involves syndicated contributions from multilateral development financial institutions (multilaterals) this will pose another hurdle. Sponsors need to be aware that multilaterals may show little inclination to negotiate any deviation from their standard project documentation.

### VII GUARANTEES

The government has been reluctant to provide sovereign guarantees in power projects to date. Perhaps as a signal of change, or given external pressures from the international business community, we understand that the government is providing contractual sovereign guarantees for the Myingyan IPP Deal (however, the creditworthiness of the EPGE will remain an issue when dealing with project financing, as the sovereign guarantees on payment are merely contractual in nature without additional security in the form of bank guarantees provided by the government).

Myanmar became a member of the Multilateral Investment Guarantee Agency (MIGA) in 2013. MIGA provides political risk insurance (guarantees) for projects in a broad range of sectors in developing member countries, covering all regions of the world. In principle, this means political risk guarantees can be provided for investments in Myanmar, which can

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\(^2\) [www.moep.gov.mm](http://www.moep.gov.mm).
include MIGA coverage for breach of contract by the EPGE. As a guide, MIGA may insure up to US$220 million per project, and if necessary more can often be arranged through a syndication of different insurers.

Under the standard MIGA contract of guarantee for shareholder loan, the guarantee holder shall, prior to or simultaneously with payment of compensation for a loss, assign and transfer to MIGA the right to a percentage of cover of the guarantee holder’s pro rata share of the Project Enterprise’s rights, as applicable, in the project agreement.

As a side note, there is also no specific protection in Myanmar against material adverse government action. However, as mentioned previously (see Section V) under the MIL the government guarantees that a business that acquires an MIC permit shall not be nationalised under the term of the contract or during the extended term of the contract. Further, the government guarantees not to suspend any investment business carried out under the MIC permit before the expiry of the permitted term without ‘sufficient cause’. What constitutes ‘sufficient cause’ is not defined. The guarantee provided under the MIL is yet to be properly tested in any Myanmar courts or arbitral tribunal, and as such there is no guiding jurisprudence or commentary.

The Public Debt Management Law 2016 (PDML) was passed on 5 January 2016, essentially to regulate matters relating to the ‘financial liabilities’ of the Myanmar government. Of possible relevance to energy projects would be the provisions of the PDML relating to guarantees issued by the state, although the precise realm of the PDML in that respect remains somewhat unclear.

The PDML provides that the Minister of Finance may issue guarantees for any person, entity or project on such terms and conditions as may be approved by the Myanmar government and the legislature. Prior to the issuance of a state guarantee and throughout the guarantee period, the Ministry of Finance shall assess the risk relating to such guarantee. If the guarantee is required to be issued in foreign currency, the Ministry shall consult with the Central Bank on the matter. However, thus far, we are yet to witness guarantees issued by the state referring to the provisions of the PDML.

**VIII PROJECT FINANCING**

The difficulties involved in financing power projects to date mainly revolve around the Central Bank of Myanmar (CBM) and MIC approval (for companies with an MIC permit) and concern loan facilities, and challenges in perfecting security interests, including the following:

- **a** charge over shares (normally referred to as a pledge of shares);
- **b** fixed and floating charges (this usually includes project accounts, movable plant and equipment, buildings and fixtures, and book debts);
- **c** mortgage over immovable property, commonly a separate land mortgage will be executed and this will be required to be registered at the relevant Myanmar Office of Registration of Deeds; and
- **d** assignment of contracts.

To comply with Myanmar property laws, foreign lenders often engage a local bank to act as an OSA to enable holding of charge over immovable property).

All of the above securities are permitted under law; however, the registration of these security interests still remains enormously challenging owing largely to complicated Myanmar
property laws and foreign ownership restrictions over land as well as a void of a modern legal mechanism allowing the government to facilitate registration of security. The first inroads were made under the Registration of Deeds Law 2018, which prescribes a more transparent two-way mechanism involving online registration with DICA followed by registration with the Deed and Registration office to properly record a security interest. However, it remains the case that there is no official land titles register or electronic database, making it difficult for investors to accurately determine the ownership of privately held land plots. When locals sell land, they often do not change the name of the title deed holder. Therefore, locals rely primarily on legal contracts, which state the transfer of land ownership after a sale. This could be confusing for investors. Hence, investors need to take care in conducting a careful due diligence process on landowners.

Use of an OSA is highly recommended to streamline the perfection of security process, as there are few restrictions in place regarding a Myanmar person (individual or corporate entity) taking the security interests listed herein. In terms of OSA responsibilities, it would be highly advantageous to request an annual declaration that the security interests remain perfected and the OSA is not aware of other interests that would affect the security remaining perfected.

Section 229(a) MIL provides for the granting by a Myanmar company of a fixed and floating charge (FFC) over its assets in favour of a lender, including book debts, cash flows, receivables, intangible assets, contractual rights and bank accounts. This is a flexible form of security that applies in the common law jurisdictions and can cover the following assets:

- a mortgage or charge for the purpose of securing any issue of debentures;
- a mortgage or charge on uncalled share capital of the company;
- a mortgage or charge on any immovable property wherever situated, or any interest therein;
- a mortgage or charge on any book debts of the company;
- a mortgage or charge, not being a pledge on any movable property of the company except stock-in-trade; or
- a floating charge on the undertaking or property of the company.

The FFC and any individual mortgage or charge over a company’s assets must be registered with DICA within 28 days of its creation, otherwise it is void against a liquidator and other creditors of the company in a winding-up. It may be pertinent to mention that the mortgage of immovable property can only be in relation to the long-term lease of the land on which the facility is built (i.e., the right to lease the land, not the land itself).

CBM approval is required for all offshore financings. Once CBM approval is obtained with the loan payment and repayment schedule attached, no further approvals are required for each payment made under the loan either from CBM. For MIC approved projects, creation of any charge or mortgage require notification to MIC.

Given the uncertainties regarding ‘onshore security’, lenders will also require overseas-based sponsors to provide ‘offshore’ security over their interests in the Myanmar-based project company in the usual manner.
IX TAX CONSIDERATIONS

Investors need to account for local tax duties when costing out an IPP project in Myanmar. Stamp duty must be levied on all project documents and any security documents if third-party project financing is involved. Pursuant to the latest bill amending the Myanmar Stamp Act 1899 dated 1 August 2017, stamp duty of 0.5 per cent of the total loan facility is applicable.

Furthermore, certain tax reliefs may potentially be available under applicable tax treaties. Myanmar has tax double taxation avoidance treaties (DTAs) in force with eight countries. These countries include India, Korea, Malaysia, Singapore, Thailand, the United Kingdom and Vietnam, with a number of other DTAs in the draft phase.

The Income Tax Law (ITL) provides that a DTA must be ‘notified’ before it is to override provisions of the ITL. The details concerning if a DTA has been ‘notified’ are contained in the Myanmar Government Gazette. Accordingly, the terms of any DTA will be followed despite anything to the contrary contained in any other provisions of the ITA.³ The sponsor must follow an administrative procedure for claiming a tax exemption based on the DTA with Myanmar’s Internal Revenue Department (IRD). Under Myanmar law, the application of the DTA is not automatic and is at the discretion of the governor of the IRD.

In terms of the tax concessions available for an MIC company, the five years income tax holiday for an MIC company starts from the first day of commercial production. Normally the project company would only incur expenditures without having any taxable income during its construction period. The project company’s corporate income tax would be nil if it has negative taxable income. However, if the project company has taxable income during its construction period, it would be liable to pay corporate income tax at 25 per cent on its net profits.

X ENVIRONMENTAL CONSIDERATIONS

Under Section 42(b) of the Environmental Conservation Law 2012, the Ministry of Environmental Conservation and Forestry has issued an Environmental Impact Assessment Procedure (EIA Procedure). The EIA Procedure states that:

\textit{[A]ll Projects undertaken by any . . . enterprise . . . which may cause impact on environmental quality . . . are required to undertake EIA to develop a project document to avoid, protect, mitigate and monitor adverse impacts caused by . . . operation . . . of a project.}

In the power sector, issues concerning air quality and greenhouse gas (GHG) emissions are prevalent. An emphasis on reducing GHG emissions is vested in local regulations addressing control measures. International guidelines providing commentary on reducing GHG emissions highly recommend the use of less-carbon-intensive fuels, combined heat, power plants, higher conversion efficient technology as well as high monitoring levels.

³ The Income Tax Law provides if the government of Myanmar enters into an agreement with any foreign state or international organisation relating to income tax, and if the agreement is notified, the terms of the agreement will be followed despite anything to the contrary contained in any other provisions of the Income Tax Law.
Myanmar’s EIA Procedure is gradually developing in the face of increasing public expectations. Health and climate change-related issues, impacts on biodiversity and sensitive habitats are among other matters of growing significance.

XI MEETINGS WITH THE REGULATORS

Meetings with any Ministry, department, division, or sub-department of the government will generally take place in Nay Pyi Taw. Aside from the MIC and Directorate of Investment and Company Administration (DICA), which have offices in Yangon, the government’s principal ministerial offices are located in Nay Pyi Taw.

Meeting requests typically are requested in letter form. Hard-copy originals must be sent to the relevant authority to arrange the meeting. Email communication remains uncommon in practice.

From our experience, meetings should be arranged at least seven business days in advance and the meeting request letters should state a preferred day and time and be accompanied by an agenda to allow the relevant authority to coordinate representatives from the MOEE, DEP, etc.

A short meeting agenda is preferable, as very frequently meetings are cut short, postponed or delayed. It is suggested, depending on the importance of the meeting, to stay overnight to afford the relevant authority more flexibility should unexpected changes occur on the initial day of the meeting.

Given these limitations, it is strongly suggested to have more frequent, short meetings as opposed to attempting a one-day ‘marathon session’ with the government.

Bringing a translator is recommended. Despite most meetings being conducted in English, having a translator available can ensure the meeting will run more efficiently.

XII INVESTOR TIPS

i Myanmar and expatriate counsel

We recommend that the investor engages experienced and skilled on-the-ground legal counsel (comprising a combination of Myanmar and expatriate counsel) to drive the entire project with the MOEE. One lead counsel acting for the sponsor is a must, considering the complications of power deals here in Myanmar. The process is long and requires the expertise of both skilled Myanmar and expatriate counsel to persist with the constant follow-up on meetings and drafting of endless bilingual letters to the MOEE. This is an enormous task for even the most experienced emerging market lawyers.

ii Patience

Myanmar’s recent political and economic reforms have been rapid and significant, paving the way for foreign investments into the country; however, this does not mean that developing a large-scale power project and doing business in Myanmar is not without its challenges. According to a 2013 report published by McKinsey:

- the average productivity of a worker in Myanmar today is US$1,500 for a year of work – about 70 per cent below that of benchmark Asian countries;
- there are four years of average schooling in Myanmar;
- there will be 10 million additional people to be absorbed into Myanmar’s large cities by 2030; and
a total investment of US$650 billion is needed by 2030 to support growth potential (US$320 billion in infrastructure alone).

Investors must be prepared to deal with the current challenges of poor infrastructure, in terms of transport, telecommunications and utilities supply. Improvements to the country’s infrastructure will take time. As Myanmar’s reform process gains speed, many draft laws and amendments are awaiting consideration by Myanmar’s parliament.

**XIII POTENTIAL DOWNSTREAM AND POWER PROJECTS**

The downstream sector, *inter alia*, involves refining petroleum crude oil, treating and purifying natural gas, and marketing and distributing petroleum products.

Recently, foreign investment has been liberalised by the Myanmar government for the importation, storage and distribution of petroleum products in Myanmar under the Petroleum and Petroleum Products Law 2017 (PPPL). It has been a welcome move for the potential downstream investors, and will create the opening of the downstream petroleum market for foreign investors in Myanmar.

The PPPL substitutes the Petroleum Act 1934, and provides clarity on aspects on import and export, transportation, storage, refinery, distribution, inspection and testing of petroleum and petroleum products. The PPPL also earmarks the authority concerned with issuance of relevant licences. However, the implementation of the provisions of the PPPL are yet to be observed.

The MOEE has been in discussion with entities on construction of new refineries and revamping of the existing refineries in Myanmar. Currently Myanmar has three major refineries: Thanlyin, Chauk and Mann Thanpayarkan. With the promulgation of the recent regulations in the sector, foreign investment is possible in connection with loading, offloading and operating and maintaining jetty facilities.

**XIV INDIAN INVESTMENT IN MYANMAR’S ENERGY SECTOR**

Aside from the Indian downstream entities (mostly publicly owned) that are dominant players in India’s downstream petroleum sector, the recent legislative developments in Myanmar have opened up potential opportunities in Myanmar.

Myanmar’s urgent need for power after years of political isolation has been well documented. Its potential for renewable energy resources is significant. Myanmar’s government has been formulating programmes for the utilisation of renewable energy resources such as wind, solar, hydro, geothermal and bioenergy for sustainable energy development in Myanmar. With various fuel sources alternatives available in Myanmar, the Indian private entities that have sophisticated technical skillsets in the energy and power sector can look forward to Myanmar as a potentially rewarding market. India also benefits from its geographical location, as it can easily cater for Myanmar’s energy requirements in the energy and power sectors.

**XV CHINESE INVESTMENT IN MYANMAR’S ENERGY SECTOR**

Driven by the One Belt, One Road initiative, first introduced to the international community in September 2013, Myanmar has witnessed a massive inflow of Chinese investment into
the country. China, like India, shares the advantage of bordering Myanmar, making it strategically well placed to support and benefit from Myanmar’s fast-growing energy sector. There is a combination of Chinese state-owned enterprises (SOEs) and private Chinese investors developing Myanmar’s energy sector; however, the majority of inbound Chinese investment into Myanmar’s energy sector is largely led by the former.

According to Myanmar official statistics released by the DICA, China is ranked as the leading foreign investor in Myanmar, boasting a volume of almost 26 per cent of Myanmar’s foreign investment value.

One of the key landmark projects in Myanmar is the China-Myanmar oil and gas pipeline, linking Myanmar’s deep-water port of Kyaukphyu (Sittwe) in the Bay of Bengal with Kunming in Yunnan province of China. This project was completed in 2014.

Three Chinese SOEs (China Electric Power Equipment and Technology Company Ltd, China Southern Power Grid Company Ltd (CSG), CSG’s subsidiary Yunnan International Company Ltd) have proposed separate plans to plug Myanmar’s national power grid into Yunnan’s electricity network. Daw Aung San Suu Kyi met with Chinese President Xi Jinping in May 2017 to discuss, among other things, Myanmar’s energy sector and developing closer ties. Our understanding, based on information released by the MOEE, is that initial talks have taken place but there has not been any further developments on this point. The Chinese and Myanmar diplomatic meetings are the most encouraging cooperation to date since the suspension of the Chinese-backed Myitsone dam back in 2011.

We envisage China to be the leaders in the development of Myanmar’s energy sector.

XVI CONCLUSIONS AND OUTLOOK

Myanmar has abundant energy resources – hydropower and natural gas in particular. Owing to underdeveloped legislation and lack of financial and technical capacity, the energy sector of the country is still underdeveloped. However, with the government’s commitment to reform, foreign investment will have more access to this sector with simplified formalities. The recent regulatory and policy changes in foreign investment are indicative of the fact that the government is making greater efforts to create a more transparent atmosphere in order to attract foreign capital and technology. We look forward to a remarkable uptick in the energy sector in the near future.
I OVERVIEW

The energy markets in the Netherlands are fully liberalised and the public electricity and gas infrastructure is operated by fully unbundled network operators. Numerous companies are active in the production and generation, and trade and supply markets. These activities are strictly separate from the operation of electricity and gas networks by independent transmission system operators (TSOs) and distribution system operators (DSOs).

However, the energy sector faces disruption and huge challenges as a result of the ‘energy transition’ (i.e., the required transformation of the traditional, fossil-fuel-based industry into a sustainable low-carbon economy). The Netherlands has been dependent on its natural gas reserves (especially the large Groningen field) for more than half a century, but this will have to change as a result of the ongoing climate debate and the increasing occurrence of earthquakes in the Groningen province (as a consequence of the production of natural gas). In a 2018 letter to the parliament, the Minister of Economic Affairs and Climate (the Minister) proposed to reduce production from the Groningen field from 21.6 billion m³ in 2017 to 12 billion m³ per year, by October 2022 at the latest. The termination of gas production in Groningen will require a series of drastic measures on both the supply and demand side. As the majority of Dutch consumers still use low calorific Groningen gas, most gas-fired equipment (for, inter alia, central heating and cooking) is not compatible with high calorific non-Groningen gas and will have to be replaced in due course. In the meantime, Gasunie Transport Services (GTS, a subsidiary of Gasunie that is designated as the national gas TSO) intends to expand its nitrogen facilities, where (imported) high calorific gas is converted into low calorific gas by adding nitrogen. The Minister recently informed the parliament that the demand for Groningen gas is decreasing faster than anticipated, as a consequence of GTS procuring additional nitrogen and accelerated reduction of gas exports to Germany.

The year 2018 was rather turbulent when it comes to energy and climate policy in the Netherlands. Further to the Paris Agreement, a much-debated new Climate Act was adopted by the Dutch lower house of parliament in December 2018. If also adopted by the Senate in 2019, the new act will set a main goal of 95 per cent emission reduction by 2049 and an intermediate target of 49 per cent emission reduction by 2030. In order to reach the proposed targets, a national, consensus-based approach was started in 2018 by

1 Sander Simonetti is a partner, and Nicolas Jans and Pieter Leopold are associates at HVG Law LLP. The authors wish to thank former senior partner Dick Weiffenbach for his valuable contribution to this chapter.
2 Letter from the Minister to the speaker of the Dutch lower house of parliament, dated 29 March 2018.
3 Letter from the Minister to the speaker of the Dutch lower house of parliament, dated 8 February 2019.
way of the ‘climate tables’. These discussion platforms involved over 100 public and private stakeholders, divided over several sector-focused groups and sub-groups, to debate proposals for emission reduction in their specific sectors: electricity production, industry, built environment, mobility and agriculture and land use. A draft agreement was reached between the stakeholders in December 2018, containing a comprehensive package of measures and proposals. However, the Netherlands Bureau for Economic Policy Analysis (CPB) and the Netherlands Environment Assessment Agency (PBL) concluded that the proposed measures will most likely not be sufficient to reach the 2030 reduction target. In addition, the Court of Appeal issued a groundbreaking judgment in the controversial Urgenda case (see Section VI), ordering the Dutch government to increase its carbon emission reduction efforts.

In view of all these developments, 2019 again promises to be an exciting year.

II REGULATION

i The regulators

The Authority for Consumers and Markets (ACM) is the designated national regulatory authority in the field of energy market regulation. The specialised Energy Department of the ACM monitors and enforces compliance with the Electricity Act 1998, the Gas Act (together: the Acts) and the Heat Act, and the rules laid down in several EU regulations and delegated legislation. To that end, the ACM has a wide range of powers to enforce compliance with energy regulations. It has the competence to impose an order subject to a penalty or a fine of up to €900,000 per violation or in some cases up to 10 per cent of a company’s annual turnover (in each case depending on the nature of the infringement). Besides ex officio investigative and enforcement powers, the ACM also has the power to resolve and settle disputes between customers and network operators and the discretion to act upon a request for enforcement action. Apart from enforcing compliance with the Acts, the ACM adopts regulation regarding tariffs and tariff-setting methodology, technical codes and rules concerning information exchange between operators.

In February 2018, the ACM published its policy priorities for 2018 and 2019. Transition of the energy supply market is one of the key priorities as the ACM wishes to ensure that the transition to sustainable energy sources takes place efficiently, while preventing the energy transition from becoming more expensive than necessary. The ACM emphasises the importance of reliable and well-functioning energy markets during the transitional period.

As regards mining, the State Supervision of Mines (SoDM) is the independent supervisory authority to monitor compliance with the Dutch Mining Act. It supervises the exploration, production, transport and storage of minerals such as oil, gas and salt, as well as geothermal heat (an increasingly important source of renewable energy). Its supervision focuses on safety, health, environment and (technically) efficient extraction. SoDM also regularly advises the Minister and other competent authorities on mining related topics.

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4 ACM was established in 2013 as a merger between the Netherlands Consumer Authority, the Netherlands Independent Post and Telecommunications Authority and the Netherlands Competitions Authority, the latter of which monitored compliance with energy regulation until 1 April 2013.
Regulated activities

The operation of electricity and gas transmission and distribution networks is strictly regulated, in accordance with the EU rules on energy market liberalisation. The Minister has appointed TenneT as the TSO for the national high-voltage electricity network and GTS as the TSO for the national gas transport network. These TSOs have been certified by the ACM to confirm their compliance with the unbundling requirements from Directive 2009/73/EC (gas) and Directive 2009/72/EC (electricity). The regional electricity and gas network operators, DSOs, are required by law to have economic ownership over their operated networks. Both TSOs and DSOs have specified tasks pursuant to the Acts and are prohibited from providing goods or services in competition with third parties (apart from certain exceptions). This competition prohibition does not apply to group companies of network operators, but these group companies may only engage in certain infrastructure-related activities, as further explained below.

In addition to transportation activities, network operators perform certain other statutory tasks as well, such as providing connections to customers and performing metering services to small (household) consumers. The provision of metering services to other than small consumers is in principle an unregulated market activity. Parties that carry out metering responsibility must be accredited by TenneT.

The supply of electricity and gas to small consumers requires a supply licence from the ACM (through delegation by the Minister). The Acts define ‘small consumers’ as users with a grid connection with a maximum capacity of 3x80A for electricity and 40m³(n)/h for gas. Suppliers can either choose to apply for a licence or cooperate with a licensed supplier and act as reseller. Applicants must demonstrate that they have the required organisational, financial and technical capabilities and comply with the applicable regulations for the supply of electricity, gas or both to small consumers. The ACM has the competence to attach conditions and restrictions to a licence, and has the right to revoke a licence.

The supply of heat to small consumers (e.g., via district heating networks) requires a licence from the ACM as well, in accordance with the Heat Act, which defines ‘small consumers’ as users with a heat grid connection with a maximum capacity of 100 kilowatts. No licence under the Heat Act is required if supplied to only up to 10 users at the same time or to one or more buildings the supplier itself owns or leases, or amounts to less than 10,000GJ of heat per year. The ACM sets the maximum tariffs for the supply of heat. An amendment to the Heat Act was adopted by the Dutch parliament on 3 July 2018. The amendment aims to increase consumer protection and create a better functioning heat market, leading to more confidence in the potential of collective heat as an alternative to natural gas. To achieve this, a number of definitions in the Heat Act are improved and clarified. In addition, it is provided that the ACM will not only determine the maximum heat prices, but also the rates for, inter alia, the connection fee and the delivery device. The new Heat Act also creates room to apply for exemptions to deviate from certain provisions by way of experiment, for instance to gain experience with new market models.

For the generation of electricity, no licence is required under the Electricity Act. However, a licence from the Minister is required for building and operating an offshore wind park, pursuant to the Offshore Wind Energy Act. The applicant must perform a feasibility study in order to apply for a licence and the Minister can attach conditions to such licence.

For balancing purposes, programme responsibility applies to the feed-in and extraction of electricity and gas from the relevant networks, which must be exercised by a programme responsible party accredited by TenneT or GTS, respectively.
Exploration and production activities regarding minerals, including oil and gas, and the exploration and production of geothermal heat, require a licence from the Minister pursuant to the Mining Act. Furthermore, the Minister can grant a licence on the basis of the Mining Act for the underground storage of substances such as gas and CO₂. Licences can be subject to conditions.

LNG installations are also subject to several provisions in the Gas Act, including the obligation to designate an operator and submit the applicable tariff structure to the ACM for approval.

iii Ownership and market access restrictions

The Acts stipulate that transmission and distribution networks, as well as the shares in TSOs and DSOs, must be owned directly or indirectly by the Dutch state, provinces, municipalities or other public bodies. The Acts also contain the group prohibition, which provides that a company that produces/generates, trades or supplies electricity or gas cannot be part of the same group of companies as a network operator. The Acts also prohibit network operators to deliver goods and provide services by means of which they enter into competition.

On 1 January 2019, the Energy Transition Progress Act entered into force, which amended the Acts to implement a set of policies that mainly aim to further define the role of the network operator and the other companies in the network company group. The legislator deems it important to protect the network infrastructure against unnecessary (commercial) risks, and to prevent network group companies from operating too broadly, thereby hampering innovation from private market parties. Therefore, the amended Acts clearly demarcate the tasks of the network operator and its group companies. The network operator is only allowed to perform certain tasks specifically assigned to it. For group companies of the network operator, an exhaustive list of allowed activities is included in the Acts. These permitted activities relate to infrastructure and network operation and include the construction and operation of cables, pipelines, electric-vehicle-charging infrastructure, installations for hydrogen, biogas and heat, as well as the provision of metering services. While introducing stricter definitions of allowed activities, the new Act also creates the possibility for the Minister to assign temporary tasks to network operators and grant exemptions from certain provisions (restrictions) in the Acts by way of experiment. A proposed new Decree on the Acts was published on 15 May 2018 and gives substance to the extended ministerial power to allow for experiments, enabling network operators and other market parties to request permission to deviate from certain provisions in the Acts in the context of specific projects or activities. By allowing such experiments, the government can examine whether certain deviations are beneficial for the energy transition and whether structural legislative changes might be needed. Other matters that are regulated by the new Energy Transition Progress Act include the possibility for the national TSOs (TenneT and GTS) to enter into cross-participations with foreign TSOs, and potential relocation or underground reconstruction of parts of the high-voltage network that are close to housing.

iv Transfer of control and assignments

The Electricity Act 1998 provides that any change of control (within the meaning of the Dutch Competition Act) with respect to a power generation plant with a nominal capacity of more than 250MW must be notified to the Minister. In cases of a change of control in an LNG installation or LNG company, a similar notification requirement applies under the Gas Act. Following such notification, the Minister assesses the risks with respect to public safety
and security of supply and may attach conditions to the change of control. An (appealable) decision will normally be taken by the Minister within four months. Transactions that are not (timely) notified are subject to possible annulment.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The Dutch government opted for unbundling of TSOs as early as in 2001, two years before European unbundling regulations were adopted in the second energy package. Under the current Acts, TSOs are subject to full ownership unbundling and certification by the ACM, which must verify that the TSO is organised and structured in accordance with the conditions of ownership unbundling. Although not required by the EU rules on energy market liberalisation, ownership unbundling is also required by law for DSOs in the Netherlands. This is reflected in the Acts by the aforementioned group prohibition that was introduced by the Independent Network Operators Act (WON). When the WON entered into force in 2008, the group prohibition was challenged before the Dutch courts by three (at the time) vertically integrated energy companies. After lengthy proceedings and a preliminary ruling from the Court of Justice of the European Union, the Dutch Supreme Court finally ruled in 2015 that the group prohibition is compatible with EU law. Subsequently, the last two remaining vertically integrated incumbent energy companies, Delta and Eneco (two of the claimants in the legal proceedings), were unbundled in 2017.

ii Transmission/transportation and distribution access

For both electricity and gas, a distinction is made in the Acts between the national transmission networks (operated by TenneT and GTS) and the regional distribution networks (operated by several DSOs). Each DSO operates the public network in its own designated region and is responsible for its construction, maintenance and operation as well as possible expansion. Access to the networks must be granted on a non-discriminatory basis and can only be denied if capacity is reasonably not available. Tariffs for use of the network are regulated pursuant to the Acts, and the entire process regarding access is supervised by the ACM.

In respect of certain private energy networks, the Acts provide for an exemption from the obligation to designate a network operator, which can be granted by the ACM to owners of closed distribution systems.

iii Tariffs

The tariffs for services rendered by network operators (transportation tariffs) are regulated by the ACM, which determines these tariffs ex ante in three steps. First, the ACM adopts a method decision for a regulatory period of three to five years. Five different types of network operators are discerned and for each of these groups a different method decision is published. The method decisions provide how the ACM will calculate the allowed revenue of the operators in question, based on efficient costs. Second, the ACM publishes X-factor decisions for each individual network operator, in which the ACM calculates the base level

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5 Parliamentary Papers Second Chamber 2010-2011, 32 814, No. 3, p. 10.
6 The two TSOs, several gas network DSOs, several electricity network DSOs and the operator of the offshore electricity network.
of revenue for the network operator and the annual tariff cut (this is the X-factor, being an efficiency factor). X-factor decisions are adopted for the same regulatory period as the method decisions they are based on. Lastly, the ACM publishes annual tariff decisions for each regulatory period, in which the maximum tariffs for each individual operator are set on the basis of the calculations in the X-factor decisions and in accordance with the tariff codes.

With respect to heat, the Heat Act provides that the ACM determines maximum tariffs for the supply of heat.

iv  Security and technology restrictions

Under a new act regarding rules on data processing and cybersecurity notification requirements, which was adopted in July 2017, companies operating in vital sectors are obliged to notify cyberattacks to the National Cyber Security Centre. The notification obligation applies irrespective of the public or private nature of a company. Vital sectors include the gas, electricity, telecommunications and drinking water sectors. Gas and electricity network operators, as well as the NAM, are mentioned explicitly in a delegated act as vital companies to which the notification obligation applies.7

IV  ENERGY MARKETS

i  Development of energy markets

On the Dutch wholesale markets for gas and electricity, various types of energy spot and forward contracts can be entered into. These energy contracts can be concluded for different periods and times. The energy markets are characterised and subdivided based on the type of contract that is offered.

In the Netherlands, GTS offers the title transfer facility (TTF) as a virtual market place that enables parties to transfer gas in the transport network (entry-paid gas) to another party. Gas can be traded on the TTF via ICE ENDEX (European Energy Derivatives Exchange) under spot and future contracts.

Electricity is traded on different markets: via exchange markets ICE ENDEX and the Amsterdam Power Exchange (APX), which is now part of the pan-European energy trading market EPEX SPOT, via the over-the-counter market and via the imbalance markets for gas and electricity that are operated by GTS and TenneT respectively. ICE ENDEX enables trading in future contracts for electricity. The APX offers day-ahead and intraday trading in electricity.

ii  Energy market rules and regulation

Exchanges for derivatives (such as futures) must be licensed by the Ministry of Finance under the Financial Services Act, and are supervised by the Netherlands Authority for the Financial Markets and the Dutch Central Bank. Parties that wish to trade on an exchange need to be members and must meet the administrative requirements that are imposed by the relevant platform.

7 Decision (order in council) of 4 December 2017, Stb. 2017, 467.
iii  Contracts for sale of energy
Suppliers of gas and electricity enter into individual supply contracts with end users. Gas and electricity prices for medium and large consumers are not regulated. Suppliers to small consumers must have a supply licence and are obliged to provide a reliable supply of energy at reasonable tariffs and conditions. These suppliers must annually inform the ACM regarding the tariffs and conditions they will apply for the supply of electricity and gas in the following year. If a supplier wishes to change its tariffs for the coming year, the new rates must be submitted to the ACM four weeks in advance. When the ACM deems the new rates to be excessive, it may impose a maximum rate in order to protect consumers.

Suppliers must also inform the ACM about organisational, financial and technical changes within their companies. In addition, licensed suppliers must have a customer complaints procedure in place and inform customers about the origin and environmental quality of the electricity supplied. Licensed suppliers are obliged to offer small consumers a model supply agreement (in accordance with the uniform model established by the ACM), but may in addition also offer other contract forms.

iv  Market developments
The Dutch government intends to close all coal-fired plants in the Netherlands by 2030 at the latest. According to the Minister, this is an important measure to achieve the required CO2 reduction. The Council of State has advised the Minister that the phasing out of coal-fired plants can best be realised by introducing a specific production prohibition.

As indicated above, an amendment to the Heat Act was adopted by the parliament on 3 July 2018. However, on 13 February 2019, the Minister announced the preparation of a new bill to further amend the Heat Act. This bill, the Heat Act 2.0, aims to anticipate the coming energy transition, where heat networks are expected to play an increasingly important role as an alternative to gas. To facilitate decision-making and investment in the construction and operation of heat networks, the Ministry intends to use the Heat Act 2.0 to elaborate on the roles and responsibilities of public and private parties, and outline the prerequisites for creating a reliable, affordable and sustainable collective heat supply. The main themes of the Heat Act 2.0 will be market and price regulation, and sustainability.

V  RENEWABLE ENERGY AND CONSERVATION
i  Development of renewable energy
A budget of €10 billion is available in 2019 for subsidies under the Renewable Energy Production Subsidy Scheme (SDE+). The SDE+ subsidy can be applied for during two subsequent application rounds (with a budget of €5 billion each).

The SDE+ subsidy scheme grants producers an annual financial compensation (during a period of 8, 12 or 15 years) for renewable energy produced and is available for the production of renewable electricity, renewable gas and renewable heat or a combination of renewable heat and electricity. The relevant renewable energy project must be realised in the Netherlands.

The SDE+ scheme is a feed-in-subsidy where the compensation is equal to the difference between the base rate and the correction amount. The base rate is equal to the production costs of the relevant renewable energy (electricity, gas or heat) and the correction amount is the energy market price. For each technology, a base energy price is determined that sets the lower limit for the correction amount and thus maximises the compensation received per unit of renewable energy.
2019 is the last year of the SDE+ in its current form. The Minister announced on 23 November 2018 that the scheme will be renamed the Stimulation of Sustainable Energy Transition Scheme (SDE++). The subsidy mechanism as such will not change, but certain amendments and extensions of subsidy categories are implemented as a result of recent developments in the energy transition. The goal of the new SDE++ scheme is to reduce CO₂ and other greenhouse gas emissions. Therefore, the subsidy will no longer be granted on the basis of generated sustainable energy, but on the basis of avoided emissions.

In January 2019, electricity network operators TenneT and Enexis reported a lack of transportation capacity to facilitate grid connections for new renewable energy (mainly solar) projects in several parts of the Netherlands. As timely grid connection is of crucial importance to project developers and financiers of solar energy projects (also in view of the realisation deadline in their SDE+ grants), the announced capacity shortage immediately gave rise to complaints from market parties and questions from the parliament. The Minister is currently investigating potential remedial actions to increase the available capacity (such as mitigating requirements for keeping back-up capacity).

In addition, the current practice of allocating transportation capacity is debated. As network operators apply the ‘first come, first serve’ principle, parties by way of anticipation often reserve capacity well in advance, sometimes years prior to the actual realisation of a project. It is questionable whether transportation capacity may be refused if there is no ‘physical congestion’ but in fact merely ‘contractual congestion’, when transportation capacity has been reserved for future projects (too) long in advance. This question becomes increasingly significant in the discussion on grid access for renewable energy projects and legal proceedings on this issue seem inevitable.

ii Energy efficiency and conservation
The Energy Agreement for Sustainable Growth (the Energy Agreement) is a public-private agreement between the Dutch government and employers, trade unions, environmental organisations and others. The Energy Agreement contains provisions on energy conservation, boosting energy generation from renewable sources and job creation, in line with the Dutch government’s aim of achieving a wholly sustainable energy system by 2050. The main goals set for achieving this sustainable energy supply system are:

a reducing final energy consumption by an average 1.5 per cent annually, which corresponds to a saving of 100PJ in the country’s final energy consumption by 2020; and

b an increase in the proportion of energy generated from renewable sources to 14 per cent in 2020, and an even further increase to 16 per cent in 2023.

In October 2017, the Energy Research Centre of the Netherlands (ECN) published the National Energy Exploration (NEV), noting that additional measures were necessary to reach the goal of 14 per cent renewable energy and 100PJ extra energy saving in 2020. The anticipated measures include the use of the Dutch government’s own substantial areas of land for the generation of renewable energy, which potential is currently being assessed on the basis of pilot projects.

In addition, pilot projects are being developed under the public-private Green Deal for Ultra-Deep Geothermal Projects between the government and seven consortia. The potential pilot projects, divided over different regions, aim to extract geothermal heat from a depth of more than 4km, with a temperature far above 100 degrees Celsius, mainly for
heat supply in the process industry. The aim of the Green Deal is to realise the three most promising ultra-deep geothermal energy projects. The projects of the consortia each have a size of approximately 1PJ.

In March 2019, the government also announced plans to financially participate in the development of geothermal heat projects in the Netherlands through Energie Beheer Nederland (EBN), the government-owned natural gas company. EBN will take a risk-bearing participation of 20 to 40 per cent in new geothermal projects. This long-awaited role of EBN in the development of geothermal heat projects will be implemented through an amendment of regulation under the Mining Act, which is expected next year. Until then, EBN participation in new projects is possible on a voluntary basis.

iii  Technological developments
The Netherlands wants to reduce the negative effects and the use of fossil energy sources such as coal, petroleum and natural gas, in order to reduce CO₂ emissions and create a more sustainable energy production. Carbon Capture and Storage (CCS) is one of the tools to achieve this. As mentioned above, the government aims at a CO₂ reduction target of 49 per cent in 2030 compared to 1990. Under the government coalition agreement, CCS is intended to play a major role in reducing industrial emissions. The coalition agreement states that ‘CCS can be a major contribution to the reduction of emissions in industry, the electricity sector and waste incineration plants’. Further incentive schemes for CCS and other low carbon technologies are currently being investigated.

VI  THE YEAR IN REVIEW
The year 2018 was characterised by an intensified public debate on energy and climate policy in the Netherlands. The ‘climate table’ approach for a national climate agreement was aimed at consensus, but caused quite a stir leading to polarisation in the political arena, with some political parties urging certain sectors to increase their reduction efforts and other political parties claiming that energy transition policy is nothing more than money-wasting ‘climate nonsense’. The energy and climate policy debate especially led to questions on the division of the financial burden of the energy transition (between industry and consumers) and whether certain parties should be compensated. Shortly after the CPB and PBL had assessed and made public their findings regarding the draft climate agreement measures and proposals, the government responded by announcing that it will decrease taxes on energy for households and introduce a carbon emission tax for businesses.

The Dutch state faced a painful legal setback in the controversial Urgenda case in November 2018, when the Court of Appeal upheld a 2015 court decision ordering the state to increase its carbon emission reduction efforts and ensure that emissions in the year 2020 will be at least 25 per cent below 1990 levels. The judgment raised praise from climate activists, but criticism from legal scholars claiming the judgment infringes on the separation of powers (arguing that emission reduction policy goals should be set by the government and parliament, not judges). The state has lodged an appeal with the Supreme Court. A judgment of the Supreme Court is not expected before the end of this year.
VII CONCLUSIONS AND OUTLOOK

Even though the Energy Transition Progress Act has just recently entered into force, a proposed new Energy Act is already anticipated (the ‘Energy Act 1.0’, to be followed up in due course by an ‘Energy Act 2.0’). This new Energy Act should eventually unify and replace the existing Acts and further streamline energy market regulation. A review of the Mining Act and related regulation is envisaged as well, in order to better facilitate the production and use of geothermal heat as a relatively new source of energy and the participation of EBN in new geothermal projects. In addition, the Netherlands will have to implement the new European Clean Energy Package, which is currently being prepared and will most likely be ready for implementation by 2021.

On 20 March 2019, elections for the twelve Provincial Councils were held in the Netherlands. These (regional) elections were of particular importance for the national government as well, since the members of the Provincial Councils elect the members of the Dutch Senate (upper house of parliament). The election results were disappointing for the current government as it lost its majority in the senate. It now needs to cooperate with other parties to gain ad hoc majorities for its legislative proposals. This could have consequences for energy-related legislation, such as the anticipated Climate Act, as the largest party in the new Dutch senate is an outspoken climate-change-sceptic party. The coming year will show what impact these developments will have.
I OVERVIEW

i Petroleum

The Nigerian petroleum industry is regulated by the Department of Petroleum Resources (DPR), an arm of the Federal Ministry of Petroleum (the Ministry). The Ministry is headed by the Minister of Petroleum Resources (the Minister). The petroleum industry is also dominated by major joint venture arrangements, production sharing contracts and service contracts between the Nigerian National Petroleum Corporation (NNPC), wholly owned by the federal government of Nigeria (FGN), and international oil companies with global operations (IOCs) and recently indigenous oil and gas companies. A number of statutes and policies encourage indigenous companies to actively participate in the industry.

Activities in the petroleum industry are regulated by several laws. These laws regulate the ownership, control and enjoyment of rights, construction and maintenance of installations, and environmental protection in the industry. The principal law regulating the exploration, production and distribution of petroleum in Nigeria is the Petroleum Act 1969 (PA).

ii Electricity

The Nigerian Electricity Regulatory Commission (NERC), established under the Electric Power Sector Reform Act 2005 (EPSRA), regulates the Nigerian electricity industry. EPSRA is the legal framework for the electricity industry. Through EPSRA, the FGN unbundled and privatised the then state-owned monopoly, the National Electric Power Authority (NEPA) into the Power Holding Company of Nigeria, generation companies (Gencos), distribution companies (Discos) and the Transmission Company of Nigeria (TCN). Today, the Gencos and Discos are controlled by private-sector investors. The FGN retains sole ownership of the TCN.

II REGULATION

i The regulators

Petroleum

The Constitution of the Federal Republic of Nigeria 1999 (as amended) (the Constitution) and the PA vest the ownership and control of petroleum under or upon any land in Nigeria, its territorial waters and exclusive economic zone in the FGN. The FGN exercises its control

1 Gbolahan Elias is presiding partner and Okechukwu J Okoro is a senior associate at G Elias & Co.
over and regulates the petroleum industry through the Ministry. The Ministry has general oversight responsibilities, and determines and formulates policies governing the petroleum industry. The Minister has broad discretionary powers to grant licences and leases; regulate construction, maintenance and operation of installations and refineries; and supervise all operations carried out under the licences and leases granted.

The DPR ensures that operators in the industry comply with the applicable laws, supervises all petroleum operations and processes applications for licences, leases and permits required to operate in the industry. The DPR also regulates the abandonment and decommissioning of installations.

The DPR and Federal Ministry of Environment (FMoE) regulate the environmental aspects of the production, transmission, distribution and supply of petroleum and petroleum products in Nigeria. Also on environmental protection, the National Environmental Standards and Regulations Enforcement Agency (Establishment) 2007 Act, the Environmental Impact Assessment Act 1992 (the EIA Act) and the Environmental Guidelines and Standards for the Petroleum Industry in Nigeria 2002 prescribe the environmental and emission standards applicable to petroleum activities in Nigeria.

There is also a ‘local content’ regulator, the Nigerian Content Development and Monitoring Board (the Board), established under the Nigerian Oil and Gas Industry Content Development Act, 2010 (NCA). The Board is required to ensure the growth of ‘Nigerian content’ in the petroleum industry.

Other regulatory agencies whose functions have an impact on the industry include:

a. the Joint Development Authority, which promotes and supervises petroleum activities in the Nigeria-Sao Tome and Principe joint development zone;

b. the Nigerian Investment Promotion Commission, which registers foreign investments in Nigeria;

c. the Central Bank of Nigeria (CBN), which under the Foreign Exchange (Monitoring and Miscellaneous Provisions) Act 1995 supervises foreign exchange dealings in Nigeria (including the importation of foreign capital and repatriation of export proceeds from oil and non-oil exports);

d. the Niger Delta Development Commission, which formulates policies and guidelines for the development of the Niger Delta area and liaises with operating companies to ensure pollution prevention and control;

e. the National Oil Spill Detection and Response Agency, which deals with waste emanating from petroleum production and exploration; and

f. the Nigerian Ports Authority and Nigeria Customs Service acting under the Nigerian Ports Authority Act 1999, the Pre-shipment Inspection of Exports Act 1996 and the Customs and Excise Management Act 1959, all of which regulate the export of petroleum.

The NNPC is not a regulator. It is a vertically integrated state-owned statutory corporation. The NNPC has various subsidiaries, one of which is the Nigerian Gas Company (NGC). The NGC owns and operates the main gas transmission systems in Nigeria. The Nigerian Petroleum Development Company Limited has the responsibility for petroleum exploration and production activities. The National Petroleum Investment Management Services, a division of the NNPC, oversees the NNPC’s interests in joint venture arrangements,
production sharing contracts and service contracts with IOCs. The Pipelines and Products Marketing Company Limited and NNPC Retail Ltd import and market refined petroleum products respectively.

There are a number of regulations made pursuant to the PA that regulate specific aspects of the industry. The Mineral Oils (Safety) Regulations 1962 prescribe standard safety measures for lessees and licensees. The Petroleum Regulations 1967 regulate importation, shipping, unshipping and landing of petroleum; storage of petroleum; transport of petroleum; fuelling of aircraft and so forth. The Petroleum (Drilling and Production) Regulations 1969 regulate applications for leases and licences, exploration and drilling, field development, and payment of fees, rents and royalties. The Petroleum Refining Regulations 1974 regulate construction, operation and maintenance of refineries.

The construction, operation and maintenance of oil pipelines are regulated by the Oil Pipelines Act 1956 and the Oil and Gas Pipeline Regulations 1995. The transportation of crude oil in Nigerian waters and payment of terminal dues on any ship evacuating oil from terminals in Nigeria are regulated by the Oil in Navigable Waters Act 1968 and Oil Terminal Dues Act 1969 respectively. The Associated Gas Re-injection Act 1979 regulates the re-injection of associated gas into oil wells. The Petroleum Profit Tax Act 1958 taxes profits from upstream mining operations in Nigeria.

**Electricity**

EPSRA is the principal statute for the electricity industry in Nigeria. Under EPSRA, NERC, as the regulator of the Nigerian electricity industry, issues regulations and orders giving effect to EPSRA. NERC is also vested with the power to grant licences for the generation, transmission, system operation, distribution, and trading of electricity. NERC is also required to promote competition and private sector participation, and ensure quality standards in the electricity industry. EPSRA further established the Rural Electrification Agency to promote, support and provide access to electric power by rural and semi-urban areas of Nigeria.

The Federal Ministry of Power (FMoP), guided by EPSRA and the FGN’s National Electric Power Policy 2001, formulates electricity policy in Nigeria. The FMoP is empowered under EPSRA to issue general policy directions to NERC on the electricity industry, and NERC is bound to comply except where such policy is in conflict with EPSRA or the Constitution. The Energy Commission of Nigeria (ECN) also plays a strategic role in the electricity industry. The ECN was established by the Energy Commission of Nigeria Act 1979 (as amended) with the mandate to plan and coordinate national policies in the field of energy, and has been promoting the use of renewable energy sources in generating electricity. The Nigerian Electricity Management Services Agency (NEMSA), established under the NEMSA Act 2015, is responsible for the enforcement of technical standards, regulations, technical inspection, testing and certification of all categories of electrical installations, electricity meters and instruments to ensure efficient production, delivery and measurement of safe, reliable and sustainable electricity power supply in Nigeria and also to guarantee the safety of lives and property in the Nigerian electricity industry.

The TCN manages the electricity transmission network in Nigeria. The TCN has two key operating officers: the systems operator and the market operator. The market operator administers the wholesale electricity market, promotes efficiency and competition. The systems operator is responsible for planning, administration and grid discipline. In addition,
the National Inland Waterways Authority established under the National Inland Waterways Authority Act 1996, regulates inland waterways navigation and issues permits for generation projects requiring water usage.

ii Regulated activities

Petroleum

The petroleum industry consists of the upstream, midstream and downstream sectors. The rights to explore, prospect, produce, process and distribute petroleum and petroleum products are granted through the issuance of leases, licences and permits by the Minister and the DPR (in some cases) to operators in these sectors.

For the upstream sector, the relevant leases and licences are the oil exploration licence (OEL), oil prospecting licence (OPL) and oil mining lease (OML). An OEL confers a non-exclusive right to explore for petroleum for a term of one year. An OEL can be further renewed for one year.

An OPL has a duration of not more than five years including renewals, and confers a right to prospect for petroleum. However, the duration of an OPL granted in respect of the deep offshore and inland basin is a minimum of five years and an aggregate period of 10 years. An OML has a duration of 20 years and is subject to renewal. The OML confers an exclusive right to explore, carry away and dispose of petroleum. A drilling rig licence is also required to operate a drilling rig while a permit is required to conduct seismic data survey.

For the midstream and downstream sectors, a licence is required to construct or operate a refinery or processing plant, export, import, store, sell or distribute petroleum and petroleum products. The approval of the DPR is required to construct and operate a petroleum products filling station, and a blending plant, and to retail lubricants. A permit is required to survey the route for a pipeline. A licence is required to construct and operate a pipeline, any pumping station, storage tanks, loading terminals or other ancillary installations. Further, to construct pipelines, a right of way must be obtained from the state government on which the land is located. This may be conveyed through a certificate of occupancy or permit from the relevant state government or by special agreement with the owner of the land (subject to payment of compensation).

DPR permits are also required to render services in the petroleum industry. The permits are in three categories: general, major; and specialised. The general category covers minor supply, works and maintenance services. The major category covers rehabilitation, upgrade and fabrication works, onshore pipeline and storage facility maintenance, equipment supply, consultancy, survey and calibration. The specialised category covers pipeline laying, drilling, exploration, technical consultancy, dredging and environmental restoration services.

The procedures for obtaining these leases, licences and permits vary but are all overseen by the DPR. In addition, the EIA Act requires the issuance of a certificate stating that an environmental assessment of a petroleum project has been conducted before one can embark on such a project, and that the outcome has been officially approved. The environmental laws of some states make it mandatory to obtain a permit from the state environmental agency to construct or operate any project or activity that affects the environment.

Electricity

As with the petroleum industry, activities in the Nigerian electricity industry are also strictly regulated. Through EPSRA, a NERC licence is required to construct, own or operate an
electricity generation, transmission, distribution, system operation or trading undertaking. Applications for licences are made in writing to the chairman of NERC, accompanied by the prescribed fees and in the manner prescribed by NERC.

Licences issued by NERC include generation licences, which authorise the licensees to construct, own, operate and maintain generation stations. A licence is not required, however, to construct or operate a generating plant not exceeding 1MW in capacity.

A transmission licence allows the licensee to carry out grid construction, operation and the maintenance of transmission system in Nigeria, or connect Nigeria with a neighbouring country. The holder of a transmission licence may also be required to carry out system operation and the procurement of ancillary services. A system operation licence authorises the licensee to carry out system operation such as generation and transmission scheduling, transmission management and coordination, procurement and scheduling of ancillary services and administration of wholesale electricity market.

A distribution licence holder has the right to construct, operate and maintain a distribution system and facilities such as supply of electricity, installation, maintenance and reading of meters, billing and collection. A licence is not required for a distribution station not exceeding 100kW in aggregate. A trading licence authorises the licensee to purchase, sell and trade in electricity. NERC may also issue a temporary bulk purchase and resale licence authorising the purchase of electrical power and ancillary services from independent power producers and Gencos for resale.

In addition to the licences required under EPSRA, the Factories Act 1987 requires factory owners (which includes electricity generating and distribution companies) to apply to the Director of Factories for registration within a month of commencement of business. A licence from the Minister of Water Resources is also required to undertake any hydroelectricity project as the Ministry of Water Resources regulates the diversion, storage, pumping or use on a commercial scale of any water.

iii Ownership and market access restrictions

Petroleum

Except for the general requirement to incorporate a Nigerian company before carrying on business in Nigeria, there are no restrictions on a foreign company acquiring an interest in the petroleum industry in Nigeria. The NCA, however, provides for certain privileges for companies in the industry with over 51 per cent Nigerian equity participation. Under the NCA, such companies will be given first consideration in the award of oil leases and licences. Also, in awarding contracts for the provision of services, Nigerian indigenous companies will be exclusively considered. The DPR also has a practice of not granting majority stakes in OPLs or OMLs to foreigners.

The Minister has the right to require refinery licence holders to deliver petroleum products to the FGN, or OPL or OML holders to deliver crude oil to a person with a refinery licence. Also, where there is a state of emergency or war, the Minister has the right of pre-emption of all petroleum obtained under a lease or licence subject to payment of an agreed price; or, if there is no such agreement, a fair price for the time being at the point of delivery as may be agreed; or in default of such an agreement, by arbitration. By the National Domestic Gas Supply and Pricing Policy (the Domestic Gas Policy) and National Gas Supply and Pricing Regulations 2008 (the Gas Pricing Regulations), OPL and OML holders are required to supply up to a specific volume of gas for domestic consumption. An OML holder is further required to relinquish-half of the leased area 10 years after the grant of the OML.
The Minister may revoke an OPL or OML if the holder is not conducting operations in accordance with the basic approved work programme and good oilfield practice, or fails to pay rent, royalties, furnish reports on its operations or comply with the PA, regulations and the terms of the licence or lease. The Minister may also revoke these rights if the holder becomes controlled directly or indirectly by a citizen of or a company incorporated in a country the laws of which do not permit citizens of Nigeria or companies incorporated in Nigeria or controlled by Nigerians to acquire, hold and operate petroleum concessions on conditions that, in the opinion of the Minister, are reasonably comparable with the conditions upon which such rights are granted to subjects of that country.

**Electricity**

EPSRA prohibits anyone holding a NERC licence from assigning or ceding his or her licence or transferring his or her undertaking without the prior consent of NERC. Similarly, no person holding a licence from NERC may, without NERC’s consent, acquire or affiliate with, the licence or undertaking of any other licensee or person who is in the business of generating, transmitting, distributing or trading electricity.

In addition, every licensee is required by NERC Regulations on National Content Development for the Nigerian Electricity Supply Industry 2013 to develop a framework for the development and promotion of ‘Nigerian content’ in the electricity industry. The licensees are also mandated to maintain a technology transfer plan (detailing various technologies deployed by the operator and the modalities for transfer to Nigerians where applicable).

**iv Transfers of control and assignments**

**Petroleum**

The prior consent of the Minister is required before any transfer of an interest, power or right in a licence or lease whether by way of acquisition, merger, takeover, exchange or transfer of shares, listing, testamentary devise, judgment or arbitral award. For the farm-out of marginal fields, the consent of the President is required. The DPR is, however, to be notified prior to the commencement of any such transaction. The responsibility for obtaining consent is that of the assignor. Also, a production-sharing contract or joint venture agreement, depending on the contractual arrangement of the parties, may require that the non-assigning parties waive or assert their pre-emption rights.

Consent will only be granted where the Minister is satisfied that the proposed assignee is of good reputation, has sufficient technical knowledge, experience and financial resources to effectively carry out the operations under the licence or lease and is in all other respects acceptable to the FGN. For the farm-out of marginal fields, the President will only give his consent if he is satisfied that it is in the public interest to do so. In the case of a non-producing marginal field, the marginal field must have been left unattended for an unreasonable time, not less than 10 years, and the parties to the farm-out must be acceptable to the FGN.

**Electricity**

NERC has the statutory responsibility to consider whether or not to approve a merger, acquisition or affiliation. To do so, NERC may require information from licensees, undertake inquiries and establish or contract with an independent entity to provide monitoring services. The prior consent of NERC is required for a licensee to assign or cede his licence or transfer his undertaking, or any part of it, by way of sale, mortgage, lease, exchange or otherwise to
another. The prior written consent of NERC is required for a licensee to acquire, by purchase or otherwise, or affiliate with, the licence or undertaking of any other licensee under the EPSRA. However, a distribution licensee may also be issued with a trading licence to provide electricity to customers.

The approval of the Securities and Exchange Commission is required for mergers, acquisitions, takeovers and business combinations. Mergers and schemes of arrangement are also required to be sanctioned by the Federal High Court. In addition, mergers, acquisitions and other forms of business arrangements concluded through schemes of arrangement are to be registered with the Corporate Affairs Commission (Nigeria’s companies’ registry) to become effective.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

**Petroleum**

The NNPC is vertically integrated. Through its subsidiaries, the NNPC engages in exploration, production, processing, importation, transportation, distribution and retail of petroleum and petroleum products. IOCs and indigenous oil and gas companies also have control over exploration, production and transportation facilities in the petroleum industry. For the IOCs, their downstream operations in Nigeria are usually not integrated with the upstream operations of the group. In exercise of statutory powers, the Minister may grant third parties access to pipelines to aid transportation of petroleum from the field or well to processing plants or terminals for export.

**Electricity**

The Nigerian electricity industry was originally controlled by the NEPA (the old, state-owned monopoly). The NEPA controlled generation, distribution, transmission and trading of electricity. Through EPSRA, the NEPA was unbundled into the Power Holding Company of Nigeria, 18 successor companies consisting of six Gencos, 11 Discos and the TCN. With the unbundling and subsequent privatisation of the NEPA, EPSRA reduced vertical integration in the electricity sector with the aim of developing a competitive electricity market in Nigeria.

ii Transmission/transportation and distribution access

**Petroleum**

In Nigeria, petroleum is usually transported from the field and well through pipelines owned and operated by a holder of an oil pipeline licence. The licence holder has exclusive rights to use the land covered by the licence for the construction of a pipeline and ancillary installations required (e.g., pumping stations, storage tanks and loading terminals) for the conveyance of petroleum, and any substance (including steam and water) used or intended to be used in the production, refining or conveying of petroleum.

However, a third party may apply to the Minister for a right to use the pipeline constructed and operated by the licence holder. Before approving such use, the Minister must consult the applicant and the licence holder. The terms for the use of the pipeline are to be negotiated between the licence holder and the applicant. Where the licence holder and the applicant fail to reach an agreement, the Minister may determine such terms. The Minister,
if satisfied with the application for use of a pipeline, may serve a notice on the licence holder to secure the applicant’s right to use the pipeline, regulate the charge payable and ensure that the applicant’s right is not prevented or impeded.

The NGC owns, operates and maintains most gas pipeline facilities in Nigeria. There are other private participants who own gas pipeline facilities in Nigeria. Transportation and storage of gas are usually governed by gas transportation agreements. The NGC imposes terms and tariffs for gas transportation agreements. To boost the gas sector, the FGN in 2008 approved a Gas Master Plan Infrastructure Blueprint, which provides for the development of central gas processing facilities and gas transmission systems.

**Electricity**

In the electricity sector, a captive power generator (generating electricity exceeding 1MW for, and that is consumed by, the generator itself, and not sold to a third party) requires the prior written consent of NERC before it can supply surplus power not exceeding 1MW to an offtaker. Such a captive generator holder must apply for a generating licence before it can supply power exceeding 1MW to an offtaker. Also, embedded power generators (generation of off-grid power to be evacuated through a distribution network to end users) with a capacity above 20MW are required to evacuate the power produced through the grid.

In respect of third-party access to transmission, transportation and distribution facilities in the electricity sector, owners and operators of these facilities are not obligated to provide third-party access. There are also no restrictions on the provision of such third-party access. Therefore, third-party use of transmission, transportation and distribution facilities in the electricity sector is based on agreements between third parties and the owners or operators.

### iii Rates

**Petroleum**

Under the PA, the Minister is to fix prices at which petroleum products may be sold in Nigeria. However, the Petroleum Products Pricing Regulatory Agency (PPPRA) Act 2003 created the PPPRA to determine the pricing policy of petroleum products, regulate the supply and distribution of petroleum products and moderate volatility in petroleum product prices. Retail petroleum product prices were previously fully subsidised by the FGN. In May 2016, the FGN announced the removal of subsidy on petroleum products. However, to date, the NNPC, as the major importer of petroleum products in Nigeria, still bears the loss for the high landing cost of petroleum products.

The price of gas in the domestic market is regulated by the Domestic Gas Policy and the Gas Pricing Regulations. The Domestic Gas Policy defines the policy of the FGN in respect of the pricing of gas to be supplied to customers in the downstream gas sector. The Department of Gas, established under the Gas Pricing Regulations, is to establish the aggregate price that shall be used as a basis for gas supply to the domestic market.

**Electricity**

NERC is responsible for creating tariff methodology in the electricity industry. In fixing the methodology, NERC is required to consider full cost-recovery plus reasonable return on investment, promotion of technology and market efficiency through incentives, fairness and openness to consumers, and reduction or elimination of cross-subsidies. NERC established the Multi-Year Tariff Order (MYTO) for the electricity industry. The MYTO provides a
15-year tariff path for the electricity industry, with limited reviews each year to cover changes in a limited number of parameters (such as inflation and gas prices) and major reviews every five years. Recently, NERC issued MYTO 2.1 for the period 1 January 2015 to 31 December 2018. Effective 1 February 2016, NERC approved an amendment to the MYTO 2.1. The new MYTO, MYTO 2015, is to be in force until 31 December 2024. The MYTO does not apply to embedded power. Embedded power is priced on a discrete basis to cover cost of production and distribution with a margin added. Purchases of embedded power are also subject to open tender.

iv Security and technology restrictions
The acquisition, promotion and development of technology in Nigeria are regulated by the National Office for Technology Acquisition and Promotion (NOTAP). NOTAP has regulatory oversight over all contracts for the transfer of foreign technology to Nigerian parties. The registrable contracts include use of trademarks and patented inventions; supply of technical expertise, detailed or basic engineering, machinery and plant; the provision of operating staff or managerial assistance; and training of personnel. Failure to register with NOTAP does not make a contract between a Nigerian and a foreign company for transfer of technology void or unenforceable, but NOTAP prohibits purchases of foreign currency from the CBN-regulated foreign exchange market to make payments under the unregistered contract.

IV ENERGY MARKETS
i Development of energy markets
The first utility company, the Nigerian Electricity Supply Company, was established in 1929, about 33 years after the first power generating station in Nigeria. From mainly hydroelectric and coal sourced energy, Nigeria has developed to a multi-source generation market (though gas is now the dominant source of power generation). The industry initially had distinct generation and transmission operations; energy was produced by the Nigeria Dams Authority and sold to the Electricity Corporation of Nigeria for distribution to end-users. These companies were integrated in 1972 to form NEPA, which was responsible for the generation, transmission, distribution of electricity and the overall management and administration of the energy market.

With the reforms introduced by the National Electric Power Policy 2001 and EPSRA, the Nigerian Bulk Electricity Trading Plc (the Bulk Trader) was incorporated. The Bulk Trader is licensed to purchase grid electricity in bulk from the Gencos and other independent power generation companies for resale to the Discos until such a time as the market would be fully competitive and the Discos achieve self-sufficiency. This arrangement is backed by both Nigerian and international governmental financial assistance in diverse forms. Another significant milestone in the energy market occurred when the National Integrated Power Project power plants built by the FGN were sold to private investors to encourage competition in the market.

ii Energy market rules and regulation
The energy market is regulated by NERC. NERC is responsible for rule-making and the licensing of market operators. The market rules in force govern the different stages the industry is anticipated to undergo; the ‘pre-transition’, ‘transitional’ and ‘medium’ stages.
The pre-transitional stage involves the unbundling of NEPA, the old, state-owned monopoly. Trading arrangements in the transitional and medium stages are and will be through contractual arrangements, and the market is expected to be centrally-administered and fully competitive.

iii Contracts for sale of energy
The applicable documentation for sale of energy will generally depend on the stage of the market in force. The Bulk Trader, as the major purchaser of on-grid power, has its standardised bulk power purchase agreements for electricity off-take from the Gencos. Vesting contracts are used for the resale of electricity by the Bulk Trader to the Discos.

For natural gas sales, gas aggregation agreements are typically used for domestic supply obligation gas (gas that producers of petroleum in Nigeria must sell locally and not export), while gas sale agreements are used for non-domestic supply obligation gas. Increasingly, private producers are developing their own standard form gas sale agreements. Template alternative energy supply agreements are also available for renewable energy projects. For the transmission and delivery of evacuated electricity, the TCN enters into grid connection agreements and transmission use of system agreement.

iv Market developments
NERC has continued to grow and reform the electric sector. It grants generation licences to investors with both on-grid and off-grid intentions. Embedded generations are now popular and have been embraced by independent generators and the Discos. Some of the ready-made National Integrated Power Project plants that were privatised, with construction shortcomings yet to be fully fixed in many cases, have been commissioned and in some cases, installed with additional capacity and are now producing electricity. NERC recently issued the Mini-grid Regulation 2017 to regulate the generation and distribution of electricity with installed capacity of 1MW and below in unserved and underserved areas independent of the national grid. NERC also issued the Meter Asset Provider Regulation 2018 (MAP) to provide for the supply, installation and maintenance of end-user meters by other parties (approved by NERC) other than the Discos. The MAP regulation is expected to close the metering gap through accelerated meter roll out and also encourage the development of independent and competitive meter services in the Nigeria electricity market.

The transitional stage of the electricity market, whereby wholesale buying and selling of electricity is based on contractual arrangements subject to regulatory rules, took off in the second month of 2015. When this stage of the market is fully in force and effect, it is expected that there will be greater investment certainty triggering investors’ interest and growth of the market. NERC’s MYTO 2015 is also in place to govern electricity pricing for both individual and industrial users.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
The clamour for renewable energy arose in Nigeria as a result of increased awareness of the environmental impacts of fossil-based generation. It was not until 2006 that the actual need for sustainable energy can be said to have been recognised by the FGN with the formulation of a renewable energy plan as part of its national energy policy to depart from a monolithic fossil-fuel economy to one driven by an increasing share of renewable energy in the national energy mix.
The FGN, NNPC and NERC have encouraged the exploration and development of renewable energy in Nigeria because of the wide range of renewable natural resources (such as hydro-power, solar, wind, geothermal, biofuel). A Renewable Energy Division was created at the NNPC to develop renewable energy initiatives. The NERC through its Renewable Energy, Research and Development Division developed the feed-in-tariff regulations for renewable energy-sourced electricity to further support the aim of generating 2,000MW of renewables-sourced electricity by 2020 and to encourage favourable pricing for such electricity. NERC also grants licences for renewable power generation like solar and coal. The Nigerian Biofuel Policy and Incentives 2007 (which specifies a plan to produce biofuel primarily for thermal and power generation) includes several tax exemptions from withholding tax, capital gains tax, value added tax and custom duties. There is a wide range of renewable energy projects at various stages of implementation. In fact, roads in numerous urban areas are lit or powered by solar sourced energy. Recently, there have been several intervention funding programmes for renewable energy projects in Nigeria. There are several ongoing small-scale off-grid renewable energy projects sponsored by the World Bank, the Association of bilateral European Development Finance Institutions (EDFI) and other DFIs in Nigeria. Also, some IOCs in Nigeria have undertaken programmes to support access to clean energy in Nigeria.

ii  Energy efficiency and conservation
Efficiency and conservation are still poorly advanced despite the inclusion of basic policies and strategies, for the efficiency and conservation of energy in the national energy policy and the energy master plan. However, there are no definitive codes and regulations for energy efficiency and conservation. The FMoE’s renewable energy programme unit has introduced initiatives to address the need to source and deploy sustainable energy sources.

The ECN established the National Centre for Energy Efficiency and Conservation. This Centre is responsible for organising and conducting research and development in energy efficiency and conservation, and has conducted studies into promoting energy efficient appliances and light bulbs. Also the ECN in partnership with the Cuban government and with support from the Economic Community of West African States has advanced the usage of compact fluorescent lamps. Likewise, under the supervision of the FGN’s National Clean Cooking Scheme, there has been production and distribution of a purpose-designed biofuel stove.

In addition, NERC has expressed its intention to develop energy-efficiency labelling standards for domestic appliances and energy efficiency standards for luminaires, air conditioners and other household appliances. Market operators have advocated the use of energy-saving equipment that is now more readily obtainable in the Nigerian market such as high-efficiency voltage controllers.

iii  Technological developments
Technological development in Nigeria is significantly slower than it should be. There are, however, indications that some Discos have signed memoranda of understanding to formalise agreements with the United States Trade and Development Agency to promote smart-grid solutions for Nigeria’s transmission and distribution challenges. We anticipate that these solutions will be in place in the near future.
VI THE YEAR IN REVIEW

i Petroleum

Recently, the international price of crude oil has been considerably stable. However, most operators of oil acreage in Nigeria are still struggling to recover from the aftermath of the decline in the price of crude oil, and settle outstanding debt service obligations. To stay afloat, these companies have resorted to debt refinancing and, in some cases, limited equity injection.

With the increase in crude oil price, the FGN’s oil revenues have also increased. The FGN recently announced its intention to retain subsidy on petroleum products. This is notwithstanding that subsidy payments were not included in the 2017 and 2018 budgets. However, about US$1billion was set aside in the 2019 budget for subsidy. As the largest importer and supplier of petroleum products in the market (over 90 per cent), the NNPC continues to bear the loss for the high landing costs of petroleum products. NNPC imports petroleum products and sells to the oil marketers who then sell to the end users. The subsidy is therefore intended to be applied towards these under-recoveries by the NNPC.

In 2017, in a move towards revamping the Nigerian petroleum industry, the FGN had approved two major policies for the sector: the National Gas Policy 2017 (NGP) and the National Petroleum Policy 2017 (NPP). As a follow up to the NDP and NPP, the President of Nigeria, in his capacity as the Minister of Petroleum Resources issued the Flare Gas (prevention of Waste and Pollution) Regulations 2018 (the Flare Gas Regulation). The Flare Gas Regulation is aimed at implementing the Nigerian Gas Flare Commercialisation Programme (NGFCP) launched in 2016. The Flare Gas Regulation, among other things, creates the framework for preventing the waste of gas, creation of social and economic benefits from gas production and disincentivising of gas flaring.

On 17 April 2019 the Nigeria Senate (upper legislative house) again passed the Petroleum Industry Governance Bill (PIGB). The PIGB is expected to deal with governance and the institutional framework for the Nigerian petroleum industry. The Bill still has to be passed by the lower legislative house and assented to by the President before it becomes law.

ii Electricity

In the past year, NERC has, despite the outcry for a review, continued to implement the MYTO-2015 electricity tariff that became effective as of 1 February 2016. The tariff, which eliminates all forms of fixed charges, has been criticised as not being cost-reflective. The MAP Regulation issued by NERC is designed to bridge the widening end-user metering gap in the Nigeria electricity supply industry, with the goal of eliminating ‘estimated billing’. Through MAP, the Discos ceases to have exclusive right to the metering of end-users. Under MAP, a new class of operators, the meter asset providers, would be responsible for the provision, installation, maintenance and the replacement of meters. However, the meter asset providers are expected to liaise with the relevant Discos to ensure compliance with industry standards in the provision of the metering services.

The year 2018 witnessed the implementation of the Eligible Customer Regulation issued by NERC in 2017 (the EC Regulation). For instance, the Association of Power Generation Companies in July 2018 announced the signing by Gencos of nine (9) power purchase agreements with eligible customers under the EC Regulation. Mainstream Energy Solutions Limited, the operator of the Kanji and Jebba generation companies also announced...
the delivery of uninterrupted 24-hour electricity to seven eligible customers as at August 2018 under the EC Regulation. Several eligible customer agreements are still being negotiated with the Gencos.

At the state level, the Lagos State government passed into law the Lagos State Electric Power Sector Reform Law 2018. The law is aimed at providing an enabling environment for generating and delivering up to 3,000MW power in three years though private sector support. The law has been applauded by actors in the industry and is expected to engender similar moves by other states in Nigeria.

VII CONCLUSIONS AND OUTLOOK

With the fluctuation in crude oil price, there have been calls from various stakeholders that the FGN should pursue an active diversification policy to move the Nigerian economy away from its dependency on oil revenues. Following these calls, there are ongoing plans for a massive reform of the Nigerian oil and gas industry. The PIGB is currently awaiting presidential assent. The PIGB, when signed, is expected to create commercially oriented and profit-driven (but government-controlled) business entities and regulators, and improve transparency and accountability. The Flare Gas Regulation has been applauded by actors in the oil and gas industry. However, to realise the laudable objectives of these policies, the FGN must commit to actively pursue and measure the implementation of these policies.

The FGN is expected to continue the electricity industry reforms. Some observers think that the current administration will deregulate and privatise the power transmission business (which is under the control of the TCN wholly owned by the FGN) to attract more foreign direct investment into the electricity industry and enhance competition in the electricity market. There is, as yet, no express communication from the current government that any fundamental changes will be made to the electricity sector.

On 17 April 2019, NERC published the consultation paper calling for comments, options, objections and representations on the regulatory framework for electricity distribution franchising. The proposed franchising regulation seeks to allow Discos to grant franchise to third parties to undertake specific Disco roles within the coverage areas. The regulation when finalised is expected to bridge power supply deficit, improve customer satisfaction, better service and improved investments in Disco networks. With multiple intervention funding programmes for renewable energy available, we expect to see many more renewable energy projects in Nigeria.
Chapter 20

PANAMA

Annette Bárcenas Olivardía and Luis Horacio Moreno IV

I OVERVIEW

Since the mid-1960s in Panama, energy related services have been rendered by a government agency called the Hydraulic and Electric Resources Institute (IRHE), which in the late 1990s was restructured into eight companies (one transmission company, three distribution companies and four generation companies) to allow for private investment in distribution and generation. The State continues to hold 100 per cent of the capital stock of the transmission company Empresa de Transmisión Eléctrica, SA (ETESA).

Being one of the fastest growing economies in Latin America, the escalation in the demand of electricity (approximately 5–6 per cent per year) has become a challenge for Panama, whose energy generated in 2017 was 64.8 per cent hydro, 29.4 per cent thermo, 4.3 per cent wind and under 2 per cent solar.

The installed capacity in Panama in 2017 was 3,336.1MW, of which 49 per cent was hydro, 39 per cent thermo, 8 per cent wind, and almost 4 per cent solar.

In 2017, the total energy sales by the distribution companies was 8,474.12GWh.

The three main subsectors of the energy market in Panama are generation, transmission and distribution. Commercialisation is also a regulated activity, but the law prescribes that commercialisation is to be performed together with the distribution activity, except that generators may commercialise their capacity or energy with large customers only.

Electricity generation is rendered in competition. Distribution/commercialisation, on the other hand, is currently limited to three concessionaires with exclusive rights in their areas of service, save for the fact that the distribution activity may be performed by other providers within isolated systems, and also under rural electrification project rules, when the distribution companies close to the project areas decline the option to provide the service.

Law 6 of 1997 dictates that the transmission and integrated operation activities shall only be performed by ETESA, but this rule is included in a provision that seeks to impose restrictions on the simultaneous provision of services. This may be why the National Authority of Public Services (ASEP) has issued a resolution governing the granting of transmission concessions to parties other than ETESA.

The law dictates that ETESA is responsible for the planning of the transmission network expansion, the construction of new assets and reinforcements to the network, as well as the operation and maintenance of the national interconnected system. ETESA is also obliged by law to mediate between generators and distributors by calling and conducting the

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1 Annette Bárcenas Olivardía is a partner and Luis Horacio Moreno IV is an associate at Alfaro Ferrer & Ramírez.
public bidding processes necessary to award power purchase agreements to ensure satisfaction of the demand that distribution companies must serve under their corresponding concession contracts.

In 2016, Panama’s government approved the National Energy Plan (PEN), prepared by the National Energy Secretariat (SNE), that defines Panama’s roadmap regarding energy policy for the next 35 years (up to 2050). The PEN is driven by four main pillars that will guide the energy policy of the country, which are:

- universal access to and reduction of energy poverty;
- the decarbonisation of the energy matrix;
- reduction and efficient use of energy; and
- energy security.

II REGULATION

i The regulators

The law assigns functions and tasks to different entities in order to assure the proper functionality of the system. These entities are as follows.

ASEP

ASEP is an autonomous governmental entity responsible for regulating public utilities, including electricity services. ASEP is bound to regulate electricity services so as to assure the constant availability of energy, to make it possible to efficiently supply the growing demand in a social, environmental and financially responsible manner. Also, this authority adopts procedures established by law to stimulate competition and is authorised to take measures to impede abuses from market agents who might have a dominant position in a moment in time.

The Authority for Consumer and Competition Protection (ACODECO)

ACODECO is an autonomous governmental entity legally empowered to investigate, verify and sanction monopolistic, anticompetitive and discriminatory behaviours and activities by agents of the market generally, including the electric market, among other powers granted by law.

ETESA

ETESA is a wholly government-owned corporation that owns the transmission network, and conducts the integrated operation of the electricity system, among other activities. Although ETESA is a regulated entity, like generators and distribution companies that are subject to ASEP’s oversight and supervision, in some respects ETESA can make certain determinations that may effect other agents of the market.

National Energy Secretariat (SNE)

The SNE is a governmental entity ascribed to the Ministry of the Presidency, whose primary task is to establish and conduct the energetic policy of the country, within the legal framework, in order to guarantee supply, access, efficient use of energy, as well as to promote its investigation, development, and sustainable growth and progress.
Wholesale Market Monitoring Group

Although not an authority per se, the Wholesale Market Monitoring Group is formed by the agents of the market, and can act as a consulting body to provide advice to ASEP regarding issues related to the wholesale market.

Legal framework

Panama's main energy legal framework may be summarised as follows:

a Law No. 6 of 1997 (as amended) dictates the institutional and regulatory framework for the provision of electricity public service. This Law is regulated by Executive Decree No. 22 of 1998;

b Law No. 45 of 2004 establishes incentives for the promotion of hydroelectric and other new, clean and renewable sources of energy. This Law is regulated by Executive Decree No. 45 of 2009;

c Law No. 44 of 2011 (as amended) dictates incentives for the development, construction and exploitation of wind power generation plants;

d Law No. 41 of 2012 dictates incentives for the promotion of construction and exploitation of natural gas-based power generation plants;

e Law No. 37 of 2013 dictates incentives for the promotion of construction, operation and maintenance of solar power generation plants; and

f Law No. 42 of 2011 dictates parameters for national policy regarding biofuel and biomass-based power generation.

A significant number of resolutions of ASEP further develop some of these laws in detail. In particular, the Operations Regulation, is a comprehensive instrument governing important operative and technical aspects of the market and the commercial rules of the market.

ii Regulated activities

The main services provided by agents of the market in the electricity sector are transmission, distribution/commercialisation and generation. However, there are other forms of participation in the sector that are also regulated, namely:

a large customers (passive or active) who can freely contract their energy needs with other agents of the market;

b companies located abroad, who can perform international exchanges of electricity using to that effect the interconnection network; and

c autogenerators and co-generators who can generate energy for their own consumption, sell excess energy in the national interconnected system and purchase backup services therein.

This section focuses on the regulatory authorisation mechanisms of the three main activities: generation, transmission and distribution/commercialisation.

In general, electricity distribution and transmission activities require concessions issued by ASEP. As to generation activities, depending on the technology used to generate electricity, the service provider may need a concession contract or a licence.
**Generation concessions**

Any person (individual or legal entity) who intends to construct and operate a hydroelectric or a geothermal generation plant must obtain a concession issued by ASEP, which ultimately takes the form of a concession contract, although the concession right is recognised previously through a resolution of ASEP.

These concessions shall be issued through processes that guarantee public concurrence, in these cases:

a. when ASEP deems necessary to develop a new hydroelectric or geothermal project; and

b. when an interested party presents a concession application to ASEP.

The bid specifications and rules for the concurrence process are dictated by ASEP, and they should reflect objective rules fostering equality and promoting the participation of investors, provided that said rules are not contrary to Law No. 6 of 1997.

As part of the process, ASEP must seek a determination from the Ministry of the Environment as to whether the natural resource needed for the project is suitable for the intended purpose. Eventually, the winning bidder will be required to obtain the approval of the environmental impact study of the project.

The term of these concession contracts may be as long as 50 years, with the possibility to be extended for an equal term. The procedures and requirements for the issuance of a concession and its subsequent formalisation through the subscription of the concession contract are established and regulated by Resolution AN No. 5558-Elec of 31 August 2012, as amended.

**Generation licences**

Any person (individual or legal entity) who intends to construct and operate an energy generation plant – other than hydroelectric and geothermal – destined for public service (i.e., fuel-based, solar and wind power) must have a licence issued by ASEP for this purpose.

Licences take the form of resolutions issued by ASEP, containing the terms and conditions pursuant to which the licence is granted in each case. No contract is entered with the authority in these cases. The generation capacity of the power plant may not be increased without authorisation from ASEP. To this effect, the licensee should file an application.

Licences shall be granted for a period of up to 40 years. Licensees may only engage in electricity generation activities.

Resolution AN No. 1021-Elec of 19 July 2007 (as amended) regulates the requirements and procedure to obtain a licence. The licensing process has two stages: provisional licence and permanent licence.

The applicant must fill out a special form approved by ASEP for purposes of applying for the licence. A guarantee of US$100 per MW or fraction of capacity to be installed for the power plant, as shown in the form, shall be submitted as well. This guarantee will be returned once the definitive licence is issued. For wind power farms, the guarantee is US$500 per MW or fraction.

The application form requires the applicant to include certain general information of itself, a technical description of the project and also to attach a number of documents that are listed in the form. Some of these documents are required to be filed during the first stage of the process in order for ASEP to issue the provisional licence for the project. The rest can be submitted as part of the second stage of the process, which leads to the issuance of the permanent licence.
With regard to a few of the most important documents required for the licence, the regulation requires:

a. a sworn statement of the treasurer of the applicant containing a list of the direct and indirect shareholders of the applicant, that is, showing the controlling interest over 100 per cent of the capital of the petitioner (in the case of investment funds or publicly traded companies, the applicant must list the members of the controlling body of the entity, i.e., the board of directors);

b. a letter of solvency and financial capacity, and the ability of the applicant to contribute at least 30 per cent of the investment necessary for the new power plant based on international costs according to the technology to be used and letters of intention of experienced power plant operators (two years) and contractors (five years);

c. a letter of viability of connection of the project issued by ETESA or by a distribution company, as the case may be;

d. environmental impact study of the project and evidence of approval by the Ministry of the Environment (typically this approval is sought within the 12-month term of the provisional licence);

e. construction bond for 10 per cent of the investment required to build the new power plant (required when the definitive licence is issued); and

f. performance bond (estimated at US$500 per MW for windpower and US$2,000 per MW for natural gas and solar projects).

The regulation specifies which of the documents required need to be filed as a condition to issue the provisional licence, which is valid for 12 months. The rest of the requirements shall be filed within the 12-month term of the provisional licence. ASEP may extend this term, as well as the terms of milestones contemplated in the definitive licence, based on a justified request of the applicant.

The provisional licence is non-transferable and does not authorise the construction of the power plant.

Once the remainder of the requirements to obtain the definitive licence are filed, ASEP shall issue the definitive licence of the power project.

Transmission concessions

Resolution JD-1244 of 10 February 1999 (as amended) governs the award of transmission concessions. Transmission concessions shall be awarded through a concurrence process, unless there are no interested competitors (except for the applicant). In the amendment enacted in 2016, ASEP provided that no concurrence process would be required in the case of companies that intend to build transmission lines and substations that will be transferred to ETESA.

Distribution concessions

Currently, most (but not all) of the country is divided into three large distribution areas, each one exploited by a distribution concessionaire that is a mixed-capital company in which the public and private sectors have interests. The participation of the private sector in these entities is the result of the public bidding acts held in the late 1990s after the restructuring of IRHE. Some of the original private equity holders have sold their interest in the companies, and therefore, share ownership has changed in time, but distribution concessions remain in effect under a regime of exclusivity within the service area of each concession.
As indicated before, the distribution activity may be carried out by third parties (other than the three main distribution companies) outside of the exclusivity regime in the case of isolated systems and in the case of projects of rural electrification.

iii Ownership and market access restrictions

No-ownership restrictions

Article 285 of the Panamanian Constitution provides that the majority portion of the capital of private companies of public interest that operate in the country shall be Panamanian, save for the exceptions contemplated in the law, which shall define them.

Further to Article 280 of the Constitution, Article 45 of Law No. 6 of 1997 specifically authorises that companies that render public services in the field of electricity may have majority foreign ownership, pursuant to the provisions of Law No. 6 of 1997.

Law No. 6 of 1997, in turn, expressly allows national or foreign capital companies (private or mixed), to participate in the electricity sector, whether by purchasing shares of state-owned electricity companies, or by obtaining and exploiting concessions or licences.

Land acquisition restrictions

Pursuant to Article 291 of the Constitution, foreign individuals or legal entities or companies whose owners are foreign, in whole or in part, may not acquire ownership of public or private land located within 10 kilometres of the national borders. Therefore, an electricity sector service provider owned directly or indirectly by foreign individuals or entities is prevented from acquiring title over the land referred to above. This rule does not encompass the use of land for an electricity sector project through means other than ownership rights.

Other restrictions

There are other restrictions that are specific for the electricity sector:

a energy generation, transmission, distribution and commercialisation companies located in Panama shall have, as sole purpose in their bylaws, one of the activities listed in Article 1 of Law No. 6 of 1997;

b activities related to the transmission and integrated operation of the interconnected national system will be undertaken by the transmission company (ETESA, as defined in the law);

c commercialisation services may be rendered by distributors, except in the case of generators who might commercialise directly with large customers;

d generation companies and their owners shall be restricted from having direct or indirect control in distribution companies, as well as requesting or applying for new concessions, if by doing so they would directly or indirectly serve more than 25 per cent of the national energy demand;

e the transmission company may not participate in activities related to the generation or distribution of energy, nor in the sale of energy to large clients;

f under certain circumstances, distribution companies and their owners may not participate or control directly or indirectly generation plants in their concession area; and

g distribution companies and their owners may not request or apply for new distribution concessions, if by doing so they would serve directly or indirectly more than 50 per cent of the total number of national clients.
iv Transfers of control and assignments

In connection with capital stock of a concessionaire or licensee: there are no special requirements to seek approval before transferring direct or indirect ownership of stock of a concessionaire or licensee. However, it is recommended to notify any changes in due course after the change of ownership occurs because one of the requirements to obtain a concession or licence is the list of direct and indirect shareholders of the applicant. There is no special regulation for this filing, which is informative in nature.

In connection with mergers and acquisitions of concessionaires or licensees: there is no specific regulation generally mandating that merger and acquisition transactions relating to electricity sector entities be subject to prior approval of ASEP. ASEP has authority to intervene in the event of practices that hinder competition (i.e., abuse of dominant position), including mergers or acquisitions with such effects.

Parties interested in entering transactions in the electricity sector may submit a voluntary consultation on whether the particular merger or acquisition is permitted.

In connection with assets of concessionaires or licensees used in the provision of electricity services: Law No. 6 of 1997 includes among the duties and obligations of electricity sector players to administer and maintain the installations and assets required for the provision of the services. However, some concession contracts contemplate specific provisions on the ability to dispose of assets required for the service. For example, in the case of generation concessions, they allow for the transfer of assets necessary to provide the service, with the prior notice to ASEP.

In connection with concessions or licences: as indicated before, provisional generation licences are not transferrable. Other licences or concessions would be typically transferrable subject to the prior approval of ASEP.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

In the 1990s, prior to IRHE’s restructuring, IRHE performed all three of the main electricity sector activities discussed herein (transmission, distribution and generation). IRHE also acted as ‘regulator’ of the sector in many – if not most – respects. Back in those days, a few private power plants had been authorised by IRHE to operate.

Law No. 6 of 1997 disaggregated these services by:

a restructuring IRHE into seven different service providers in which the private sector would have stakes, as described before;

b creating restrictions in the law leading to avoid the provision of services in a way that would permit vertical integration; and

c creating a clear regime of competition in generation activities, enabling large customers to become players in their own merit and regulating other alternatives for players of the market to participate (i.e., autogenerators and co-generators).

Also, special rules have been dictated for electricity sector players to share infrastructure with other agents of the market through remunerated commercial contracts.

Pursuant to Law No. 6 of 1997, a general rule applicable to all electricity market players is to facilitate access and interconnection of other entities who render public services, or who are large customers of the latter, to lines and substations used in the organisation and provision of the services.
Finally, natural gas projects are a new occurrence, and they began to make an appearance in the electricity forum of Panama not long ago. The first natural gas power plant has not yet come online, but it is expected to do so in the following months. Two others have been authorised to date.

ii Transmission/transportation and distribution access

As indicated before, concessionaires of the electricity market must facilitate access and interconnection to lines and substations used in the organisation and provision of the services to other entities who render public services, or to large customers. For instance, a distribution company shall permit a generator to connect to the transmission network indirectly through the distribution network’s assets, if required, subject to viability based on technical studies. Another example would be a generator who has installed transmission capacity for itself. Such capacity may be sought by another generator to connect to the grid.

The law does not currently allow for competition in the commercialisation of services to end customers. Regulated customers, which are the vast majority of customers of distribution companies, may only be served by the distribution company in their concession zone, which is under a regime of exclusivity. The remaining customers are large customers, who may negotiate their supply agreements with generators.

The rules encouraging competition, which have mainly focused on generation, have been fruitful, as can be seen judging by the large number of projects (in all technologies) that have been or are being constructed after enactment of Law No. 6 of 1997.

The next step in the promotion of competition appears to be the reduction of restrictions on the activity of commercialisation (referred to below).

iii Rates

Sales of energy to large customers is subject to a regime of mutually agreed pricing. There are no tariffs to apply.

For sales to regulated customers, the Law requires ASEP to dictate the applicable tariff regime for each activity, which serves as a general framework of methodologies and formulas that the market agents must then apply to produce their own tariffs. The tariff regime approved by ASEP is valid for four years unless corrections are needed in the event of errors.

For distribution, ASEP shall define the profitability rate deemed reasonable for the concessionaire, taking into account the latter’s efficiency, the quality of its service, its investment programme for the period of validity of the tariff formulas and any other factor deemed relevant.

For transmission, costs used to calculate the tariff must enable ETESA to have a reasonable rate of return before taxes, over the fixed net asset, at the original cost. For purposes of this calculation, the law contemplates rules on how to determine a reasonable rate.

iv Security and technology restrictions

Although Law No. 6 of 1997 does not explicitly regulates topics such as homeland security, law enforcement, protection of critical infrastructure and network security, it does define generation, transmission, distribution and commercialisation of electricity as services of public interest destined to satisfy collective needs of the general public. As a general rule, the state must intervene in such services of public interest in order to guarantee the efficient, continuous and uninterrupted service provision.
The Criminal Code of Panama includes penalties ranging from three to five years of jail time for those who seize movable property destined for electricity public services.

Similarly, the Criminal Code also includes penalties ranging from five to 10 years of jail time for those who damage or make useless networks, channels or works destined for the transmission of energy, gas or energy substances.

In general, providers of electricity public service have, among others, the following obligations. They must:

a. assure that the service is provided continuously and efficiently, without abuse of dominant position;
b. avoid monopolistic or competition restrictive practices;
c. provide for the end customers that are entitled to receive the subsidies granted by the authorities;
d. divulge the efficient and safe way to use the public service;
e. protect the environment in the execution of their daily functions;
f. facilitate the interconnection access to other companies or entities providing public services and to their large customers;
g. provide collaboration to the authorities in cases of public calamity to avoid harm or injury to the end users;
h. register with the regulatory authority and provide notification of commencement of the services;
i. respond for damage caused to the end customers; and
j. provide clear information to the end customers regarding the services and the costs.

Among the transmission company’s obligations are the following. They must:

a. provide for the transmission service as established in Law No. 6 of 1997;
b. prepare the generation expansion plan of the interconnected national system;
c. prepare the transmission expansion plan for the interconnected national system;
d. undertake basic studies required to identify possible hydroelectric and geothermic developments; and
\n\text{e. expand, operate, maintain and provide services related to the national network of meteorology and hydrology.}

Among the distribution company’s obligations are the following. They must:

a. provide the energy distribution service within its corresponding concession area;
b. extend their services to rural areas within its corresponding concession area;
c. comply with the terms of the concession agreement, and provide the services in a regular and continuous manner within the concession area;
d. expand the distribution networks when required to serve the increase in demand within the concession area; and
\text{e. keep the fees for the services public and accessible to the customers.}

\text{IV ENERGY MARKETS}

i. Development of energy markets

Under the law and more specifically under the Commercial Rules of the Wholesale Electricity Market, which is part of the Operations Regulation, two markets are recognised: the spot market and the contract market.
A general rule in Law No. 6 of 1997 obligates distribution companies to enter into power purchase agreements to meet the demand in their concession zone. Currently, ETESA calls and conducts the public bids required to award power purchase agreements (PPAs) intended to satisfy the general obligation of Law No. 6 of 1997. ETESA acts as an intermediary between distributors and generators in said processes.

When IRHE had been just restructured, the initial bids for PPAs were open to participants from all generation technologies. With the passage of time, some bids called only for certain technologies. As a result, there have been solar-only, wind power-only and natural gas power-only bids. Through this contracting policy – which refers only to the moment of procuring the PPA – for the past few years, the government has been trying to reshape the composition of the generation matrix of the country.

In the contract market bids are called for different products, for instance, power-only, power and energy or energy-only. However, again, this refers only to the moment of procuring the PPA.

Dispatch in the market occurs in ascending order of variable cost, regardless of the conditions of a particular PPA.

ii Contracts for sale of energy
Large customers may freely negotiate individual contracts for the purchase of capacity or energy with generators of the market. There are no regulatory requirements limiting pricing or establishing rates.

The parties may agree to include in these contracts an arbitration clause to submit to arbitration by ASEP in the event of disputes; and therefore, only if a party submits a dispute to ASEP would the authority have the ability to intervene to dictate a solution.

There is no natural gas market in Panama. The gas necessary for the large gas power plants being installed will have to be imported.

iii Market developments
Currently, Law Project 573 is being discussed at the National Assembly (it is still in a very early stage). If approved, this Law Project would modify Law No. 6 of 1997 in various aspects, including the recognition of the ‘commercialisation’ activity in the energy market outside of the current bounds of the Law. The ‘marketer’ (person undertaking the commercialisation activity) would be allowed to commercialise energy between the distributors, large clients and other market agents, as well as between generators and large clients.

This Law Project anticipates the elimination of the rule that makes it mandatory for all generators with uncompromised capacity to submit bids for PPAs when bids are called, and the abolition of special bids for the purchase of energy by specific technology.

Additionally, this Law Project intends to include a mechanism to provide incentives for the use of renewable energy by including public bids for the purchase of energy and evaluation criteria that penalise CO₂ emissions.

V RENEWABLE ENERGY AND CONSERVATION
i Development of renewable energy
Law No. 45 of 2004 establishes a number of general incentives for the promotion of energy generation systems fuelled by new, renewable and clean sources.
Some of the tax incentives are the following: exoneration of import tax, tariffs, rates, and other contributions caused by the importation of equipment, machines, materials and parts necessary for the construction, operation and maintenance of generation systems fuelled by clean and renewable sources.

There are also tax incentives based on the reduction of tons of CO₂ emissions, which may be used for the payment of income tax during the first 10 years counted from the beginning of the project’s commercial operations.

More specific laws for the different types of energy sources regulate the corresponding incentives for each source. Among them are the following:

a. Law No. 44 of 2011 establishes incentives for the construction and operation of wind generation plants;
b. Law No. 37 of 2013 establishes incentives for the construction and operation of solar generation plants; and
c. Law No. 41 of 2012 establishes incentives for the construction and operation of natural gas generation plants.

The PEN, prepared by the SNE as per Law No. 43 of 2011, includes as a short-term project the consolidation and harmonisation of existing regulations regarding renewable energy into one law.

ii Technological developments

Panama is taking its first steps towards being conscientious about smart grids in governmental affairs and in relation to citizens. Perhaps the entity that is the most advanced in taking the first steps towards implementing the concept of a smart city is the municipality of Panama. While no special regulatory effort appears to be in the pipeline for smart grid technology as it pertains to the electricity sector, it is clear that both ASEP and the SNE are actively joining forces with other government entities such as the Municipality to promote the common goal to incorporate technology to empower citizens.

VI THE YEAR IN REVIEW

The following are among the most relevant occurrences:

a. The much-needed Third Transmission Line is reaching completion and portions thereof have become operational already.

b. A new public bid is in process for the construction of the Fourth Transmission Line with a capacity of 1,280MW by circuit of 230kV, with possible expansion to 500kV, with an approximate length of 300 kilometres. Proposals are expected to be presented by participants on April 2019.

c. Law Project 573, which amends Law No. 6 of 1997, is still being discussed and if approved, a more liberalised form of commercialisation activity will be a reality in Panama.

d. The current trend in large power plant investment is natural gas. There are currently three concessions awarded, one of them in advanced stages of construction.

e. Another project that is being discussed is the Colombia–Panama interconnection line through underwater cable with a capacity of 400MW.
VII CONCLUSIONS & OUTLOOK

The Panamanian electricity sector is expected to continue to attract investment. A relatively clear-cut regulation to obtain the relevant concessions and licences is among the strengths of the system.

If the new rules on commercialisation are enacted, the dynamics of the system will change and there must necessarily be a time to adapt to change. The regulator should make sure that clear regulation is in place and proper divulgation is made, to avoid confusion in the applicable rules that pertain to commercialisation with regard to the traditional methods to purchase and sale power and energy.
Chapter 21

POLAND

Iga Lis and Ada Szon

I  OVERVIEW

The Polish energy mix is based on hard coal and lignite, which covers more than 80 per cent of the generation. Gas fuels, onshore wind farms, photovoltaic, hydropower and biomass installations are responsible for the rest of the energy generation. There are no offshore wind farms and nuclear power units in Poland. However, in the Energy Policy for Poland until 2040, published by the government, it is highlighted that the energy mix should change in the next years; in particular, the government assumes that in 2030 the participation of hard coal and lignite in the energy mix should not exceed 60 per cent of the generation. Nevertheless, last year, construction commenced on a new coal-fired power plant with a capacity of 1,000MW.

In previous years, the development of renewable energy generation was significant, particularly with respect to onshore wind farms. This growth was supported by ‘green’ certificates (issued for renewable energy only); however, a slowdown occurred in 2012, when the price for the ‘green’ certificates decreased sharply. As a result, a new act pertaining to renewable energy was announced in 2015 and a new support system, in the form of auctions, was implemented. Then, in 2016, another turning point for onshore wind farms took place due to the changes proposed by the Act on Wind Energy Investments; following the introduction of these changes, the development of renewable projects was essentially frozen. Currently, the government prefers offshore wind projects. At the same time, three independent large projects are being developed – two by the state-controlled companies – PGE SA (the biggest energy group in Poland) and PKN Orlen SA (the leading Polish oil company) and the third one jointly by Equinor and Polenergia (a private Polish company).

With respect to natural gas, Polish sources cover only 25 per cent of the market demand and the majority of natural gas is imported. From 2016, Poland no longer imports gas solely from Russia, as a new LNG terminal in Świnoujście covers part of the gas demand. In order to diversify the natural gas supply sources, two independent projects are currently being undertaken – extension of the LNG terminal and a new gas connection with Norway, the ‘Baltic Pipe’.

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1 Iga Lis is a partner and Ada Szon is a lawyer at CMS.
II REGULATION

i The regulators

The regulatory authority

In Poland, the administrative authorities that are responsible for determining the regulatory policy are the Minister of Energy and the president of the Energy Regulatory Authority (ERA). As the Minister of Energy is responsible for the legislative process (i.e., preparation and adoption of legislative acts, as well as creating the policy with respect to the energy market) the President of ERA plays the role of the regulator of activities of energy market participants.

The President of ERA is appointed for five years by the Prime Minister in an open and competitive recruitment process. He may be re-appointed only once. The regulator shall be impartial and independent from any public or private entities. The president is supported by the vice-president of the ERA who is also appointed for a period of five years and may be re-appointed only once.

The scope of the powers and obligations of the President of ERA is very broad. His or her general obligation is to monitor the functioning of the whole energy market, that is, all the segments of the energy industry including electricity and gas markets. He is also entitled to grant licences to conduct business activity in Poland, and approve the tariffs for electricity, gas and heat. The President of ERA is also responsible for managing the auction system (in the area of renewable energy and capacity mechanism), which aims to grant state support for selected projects. Moreover, he or she has the power to control the fulfilment of the obligations set forth in the relevant legislation and to impose financial penalties for violating those obligations.

Main sources of law in Poland

The main act setting forth the general framework for the energy sector in Poland is the Energy Law. This statute defines the basic terms regarding the energy sector and provides the rights and obligations of the main market participants, defines the powers and obligations of the administrative authorities (such as the President of ERA), and sets forth the conditions for conducting business activities in the energy market in Poland.

However, there are many other laws regulating specific subsectors of the energy industry. With respect to electricity, the key legislative acts that promote clean energy in Poland are the Act on Renewable Energy Sources, the Act on the Promotion of Electricity from High-Efficiency Cogeneration as well as the Act on Electromobility and Alternative Fuels. Another key act is the Act on the Capacity Mechanism, which provides a support scheme for electricity generation. The framework for the gas industry is set out in the Energy Law, but also in the Act on Mandatory Stocks of Crude Oil, Crude Oil Products and Natural Gas and on the Principles of Proceeding in Case of a Threat to National Fuel Security and Disruptions on the Crude Oil Market.

Acts of Parliament are not the only source of law regulating the energy market in Poland. When it comes to technical information or information pertaining to very narrow issues, such as rules for the preparation of the tariffs for electricity, gas and heat, are usually set out in the regulations. One of the government bodies issues these; in this case, it is usually the Minister of Energy.
Although not legally binding, one of the key acts that presents the Polish strategy with respect to the energy sector is the Energy Policy for Poland until 2040. A draft of the Energy Policy, proposed by the Minister of Energy, sets out the government’s plans for the development of the energy market and the changes that will affect the industry.

As the energy market in Poland is a regulated market, one of the most important acts that create the legal basis for conducting business activities in the field of energy are administrative decisions issued by the President of ERA. The regulator is authorised to issue licences for energy companies that *inter alia* trade in electricity or natural gas and to render decisions in which it can impose financial penalties for violations of the Energy Law or other relevant acts.

**Regulated activities**

Conducting business activities in the energy market in Poland is subject to approval of the President of ERA. The approval is given by means of an administrative decision – the licence for conducting the business activity.

The list of activities that are subject to licence is set forth in the Energy Law. The obligation to obtain a licence encompasses such activities as the generation of energy and fuels, storage of gaseous fuels, transmission and distribution of energy and fuels, as well as trading in energy and fuels. However, there are some exceptions, for instance, a licence is not required for trading in electricity on the Polish Power Exchange.

If the energy company is willing to commence one of the above-mentioned activities, it has to apply for a licence to the President of ERA. In the last couple of years, the requirements set forth for such entities have been substantially expanded. The president issues the licence to the applicant, which must have its seat in the European Union, Swiss Confederation, a European Free Trade Association member country or Turkey; have the financial resources and technical capacity to guarantee proper performance of the licenced activity; and ensure the employment of individuals of appropriate professional competence.

**Ownership and market access restrictions**

In Poland, there are not many restrictions imposed on energy companies willing to do business in the field of energy. However, as a licence is the key requirement paving the way for such activities, some specific limitations for licence holders and for entities applying for a licence should be mentioned.

Firstly, a licence shall not be granted to an entity that does not have its seat in the European Union, Swiss Confederation, European Free Trade Association member country or Turkey. Likewise, the President of ERA will not grant a licence if:

a the energy company is declared bankrupt;

b the energy company has been convicted of any offence or tax offence related to the economic activity conducted by the company;

c the energy company is not registered as a VAT taxpayer; and

d an entity that has significant influence or has control or joint control within the meaning of the relevant provisions of the Polish Act on Accounting was convicted in the past three years of any offence or tax offence related to economic activity under the Energy Law.
Secondly, if an entity is granted the licence, it must observe the rules set therein as well as statutory obligations provided mainly in the Energy Law. The President of ERA will revoke the licence if the energy company violates its provisions.

Apart from the above, energy companies may face other limitations, which vary according to the type of activities they are performing. For instance, with respect to electricity traders, such limitations regarding prices for electric energy may be found in the internal regulations of the Power Exchange as well as the Transmission Network Code, such as provisions regulating pricing on the balancing market.

Transfers of control and assignments

In Poland, mergers or acquisitions are subject to notification to the President of the Office of Competition and Consumer Protection, which is the administrative authority responsible for supervising the competition on the Polish market and assessing the concentrations.

The relevant entity is obliged to submit a complete merger notification and pay the fee. The President of the Office of Competition and Consumer Protection will issue a decision within one month from the start of the merger control proceedings. However, if the President raises some competition concerns or requires market inquiry, the deadline can be extended by an additional four-month period.

Along with the President of the Office of Competition and Consumer Protection, the European Commission also reviews mergers and acquisitions. This is the case when the merger or acquisition has a community aspect (for instance, a significant presence in the European Union).

According to the Act on Control of Certain Investments, the Minister of Energy is allowed to prohibit the acquisition of shares in an energy company if the transaction is deemed contrary to the interests of national security, human rights and environmental protection.

III TRANSMISSION/TRANSPORTATION & DISTRIBUTION SERVICES

i Vertical integration and unbundling

As required by the EU and Polish regulations, the operation of the national transmission grids for electricity and natural gas is carried out in accordance with the unbundling rules. In both electricity and gas sectors – the transmission system operators are the state-owned companies. Polskie Sieci Energetyczne SA is responsible for the electricity grid and OGP GAZ-System SA is responsible for the natural gas grid.

In 2013, as a consequence of the mandatory implementation of Directives 2009/72/EC and 2009/73/EC (the Third Energy Package), the Energy Law was amended in order to separate the grid activities (transmission and distribution) from activities in the area of production and trade in gaseous fuels and electricity. Previously, both grid activities were regulated in the same way. The fundamental part of this amendment covers the new regulation in respect of the transmission system operators and storage system operators. The transmission system operator is obliged to:

a have legal and organisational independence as well as the freedom to make its business decisions;

b refrain from the business activities related to the production, generation or trade of gaseous fuels or electricity; and

c ensure third-party access.
Such framework of the legislation secures the fulfilment of the European Union requirements. The abovementioned regulation has not changed deeply the unbundling rules related to the distribution system operators existing in the vertically integrated structure. For the distribution industry, the legal and organisational independence, independence of making decisions and the lack of the personal connection are also required.

ii Transmission/transportation and distribution access

The obligation to introduce TPA rule also resulted from the Third Energy Package, which was implemented by the Polish legislator. The transmission system operator is required to deliver transmission services to all final customers and electricity traders or generators on an equal treatment basis. The same applies to the distribution system operators. To obtain these services, the applying party must enter into a transmission or distribution service agreement. By law, they must provide access to third parties on the objective and competitive rules.

iii Rates

Operators prepare the tariffs for gaseous fuels and energy in accordance with the rules set forth by the Energy Law and the relevant regulations, and present them to the President of ERA for approval. These provisions set the legal limits within which the President of ERA may approve or reject such tariffs. Tariffs should in particular ensure the legitimate business operation costs of the operator are covered, along with a reasonable return on capital and the protection of customers against unjustified rates.

iv Security and technology restrictions

The Polish regulations regarding the critical infrastructure meet the requirements of Directive 2008/114/EC. The critical infrastructure is defined as systems and their functionally related objects, including construction objects, devices, installations, key services for the security of the state and its citizens, and to ensure the efficient functioning of public administration bodies, as well as institutions and entrepreneurs. Certainly, the critical infrastructure covers the systems of energy and fuels. The designation of a given facility, device or installation as critical infrastructure imposes several obligations on its operators. These obligations include preparation and implementation, in accordance with the anticipated threats, of plans for critical infrastructure protection and maintenance of their own reserve systems ensuring security and maintenance of the functioning of this infrastructure until it is fully restored.

Additionally, as a part of the implementation of NIS Directive, the Act on the National Cybersecurity System was adopted in 2018. One of the strategic sectors covered by this Act is the energy sector. The energy companies that are affected by the obligations arising from the Act had to obtain the decision regarding their classification as an operator of key services by November 2018. If the company has been classified as an operator of the key services, it is obliged to commence fulfilling the statutory requirements pertaining to cybersecurity.

IV ENERGY MARKETS

i Development of energy markets

Trading in energy is possible on the commodities exchange, Polish Power Exchange, which is run by the Towarowa Giełda Energii SA.
The Polish Power Exchange operates a commodity exchange for trade in, among others, electricity, liquid and gaseous fuels, emission allowances. It operates on the following markets: day ahead market, intraday market, day ahead market gas, commodity forward instruments market with physical delivery, commodity forward instruments market with physical delivery gas, property rights market for renewable energy sources and co-generation, as well as CO₂ emission allowance market.

ii Energy market rules and regulation

Generally, the Polish legal regulations concerning the electricity market do not include limitations as to the prices for electric energy. However, there might be some restrictions set in the internal regulations of the Polish Power Exchange.

This also applies to the ‘balancing market’, that is, part of the overall electricity market in which the needs of balancing services are met. In this case, price setting and the limitations in this respect are regulated in the Transmission Network Code as well as in accordance with EU and ACER documents.

iii Contracts for sale of energy

Apart from trading on the organised market such as the one run by the Polish Power Exchange, market participants are allowed to enter into bilateral contracts that create the over-the-counter market. The price and other contractual terms of these bilateral contracts are the result of the negotiations between the parties. According to the Civil Law rule of freedom of contract, the parties are free to determine the terms in their contracts that are not disclosed to the other market participants.

iv Market developments

It should be noted that Poland has committed to changing electricity price limits on the balancing market on the wholesale electricity market. From 1 January 2019, the electricity price limits on the balancing market will not be lower than the limits on the intraday market. The limits must be coherent with the Commission Regulation (EU) 2015/1022 of 24 July 2015, with ACER decision No. 5/2017 of 14 November 2017 and with Commission Regulation (EU) 2017/2195. Hitherto, the price limits amounted to 70 PLN/MWh and 1,500 PLN/MWh.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The government’s goal is to achieve the renewable energy target for 2020 set by the European Union at the level of 15 per cent in the energy mix. To be able to reach this level, the government provides strong support to renewable energy projects, which was clearly visible in 2018.

The Polish government decided to support the renewable energy projects by granting various types of state aid. The most significant one is the auction system in which the installations will obtain financial support after winning the auctions organised by the President of ERA. However, the amendment to the Act on Renewable Energy Sources adopted in 2018
not only shaped the auction system but also introduced two other support schemes, namely feed-in-tariff (FIT) and feed-in-premium (FIP) systems. Under these two support systems, small capacity hydro and biogas installations are supported.

The government also plans to soften the requirements set forth for new investments in the Act on Wind Energy Investments. Currently, it is not allowed to locate and build a wind farm if the distance from residential buildings is shorter than 10 times the height of the wind farm, which is measured from the ground to the highest point of the wind turbine plus its technical components (i.e., the rotor blades). The Minister of Energy wants to shorten this distance to allow a greater number of wind projects to be developed; however, no official draft of the amendment to the Act has been published.

ii Energy efficiency and conservation

The Council of Ministers adopted on 23 January 2018 the National Energy Efficiency Action Plan for Poland. This document consists in the summary of the additional measures intended to contribute to the overall energy efficiency target of 20 per cent primary energy consumption savings in the European Union by 2020. The plan provides a description of energy-efficiency-improvement measures by end-use sectors. These measures include a white certificates system, national advisory support system and informational campaigns.

In the area of energy efficiency, there are also programs prepared by the National Fund for Environmental Protection and Water Management or within the Operational Programme on Infrastructure and the Environment 2014–2020. The aim is to enhance energy efficiency of buildings, in the industry and in transport.

iii Technological developments

The government highly supports the development of new technologies in Poland. In 2018, the Minister of Energy published a draft amendment of the Energy Law pertaining to the development of energy storage and smart metering. In this document, the Minister sets forth the framework for storage activities, define basic terms in this respect, provide clear rules for connecting the stores to the grid. The draft amendment in the beginning of 2019 was still in the process of public consultations, thus, the final form and rules are still to be determined.

Not only does the government undertake legislative actions, it also supports the technological developments financially. In 2018, some energy companies received financial grants from the Operational Programme on Infrastructure and the Environment 2014–2020. One of these companies is Tauron Dystrybcja SA, which received over 9 million zlotys for a demonstration project for a stationary energy storage system as a smart grid element. Another company – PCC Rokita SA – will receive over 8 million zlotys for the construction of two projects: intelligent power station and electric power stations in the sewage treatment plant. Due to the modernisation of the station and the implementation of the smart grid system, the losses in energy transmission will be reduced and use of electricity will be more efficient.

Support for the energy companies is a long-term support measure, as in previous years other companies obtained such grants. For instance in 2017 Energa-Operator SA obtained financial support for the project ‘Reconstruction of the grid to Smart Grid standards by installation of smart metering and network automation to activate final customers to improve the energy efficiency and efficient power system management for improving security of supply’.
Projects developing smart cities are also supported. In December 2018, the ‘Smart City Siechnice’ project, conducted by ESV3 Sp. z o.o., was granted over 2 million zlotys to adapt the electricity distribution network in the area of the Siechnice and Oława municipalities to the requirements of the smart grid.

VI THE YEAR IN REVIEW

i The Energy Policy for Poland until 2040

In 2018, the Minister of Energy published a draft of the Energy Policy for Poland until 2040. This document, which was highly anticipated by market participants, presents the long-term strategy in the Polish energy sector. The strategy takes into account the present situation in the Polish energy market and also current trends and goals that the Polish government is aiming to achieve in the next few decades. The Energy Policy has been designed to mirror the EU strategy presented in the ‘Clean Energy for All Europeans’ legislative package, known as the ‘Winter Package’.

One of the key issues in the Energy Policy is a plan to construct a nuclear power plant. As of now, this is still in the distant future; however, the Minister of Energy seems to be determined to develop this project in order to gradually replace the coal-fired plants.

ii Capacity mechanism

One of the milestones in the Polish energy sector in 2018 was the decision issued by the European Commission on 7 February 2018 (State Aid No. SA.46100 (2017/N) – Poland – Planned Polish capacity mechanism) in which the Polish electricity capacity market was approved. In its decision the Commission has found the Polish capacity mechanism to be compatible with the internal market in accordance with Article 107(3)(c) of the Treaty on the Functioning of the European Union.

The Polish capacity market, regulated in the Act on the Capacity Market adopted in December 2017, was based on the British model of the capacity mechanism. This mechanism provides for remuneration, which electricity generators will receive for their availability to generate electricity, whereas demand-side-response will benefit from the reduction of their electricity consumption.

The first auctions, which were conducted for the 2021–2023 delivery period, took place in the fourth quarter of 2018.

iii Renewable energy

At the end of 2017, the European Commission approved the new support system for renewable energy sources in its decision of 13 December 2017 (State Aid SA.43697 (2015/N) – Polish support scheme for RES and relief for energy-intensive users). Therefore, the Polish legislator introduced material changes to the Act of 20 February 2015 on Renewable Energy Sources to set the framework for the new support scheme.

Until now, Poland has been supporting renewable energy sources through its system of certificates of origin of electric energy. However, the Polish legislator decided to incentivise the development of renewable energy in Poland by setting up a new support scheme in the form of auctions. This measure will apply to installations with a rated output above 500kW, which will obtain the right to cover the negative balance that will constitute the difference between the price included in the offer for an auction and the price actually applied in the sale transactions. With respect to installations with a rated output below 500kW – they will

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be allowed to sell electricity to an ‘obliged seller’ after concluding a contract with him. The contract is to specify the price of electricity expressed in zlotys for 1MWh determined by auction and the amount of electricity in MWh, which the energy generator is obliged to produce in the following years.

The first auctions for renewables were conducted in the fourth quarter of 2018.

iv Electromobility

Another key legislative act is the Act of 11 January 2018 on Electromobility and Alternative Fuels. The idea behind this act is to promote and develop electromobility in Poland. As this is the first act fully dedicated to this issue, it sets the framework for the development of the necessary alternative fuels infrastructure. To speed up the process, the Polish legislator provided for some administrative benefits (such as no obligation to obtain a building permit in the case of charging stations or charging points).

The act also supports vehicle owners. It sets out a number of tax measures to facilitate electromobility by introducing excise exemptions for electric vehicles and hydrogen-powered vehicles and a temporary excise exemption for hybrid vehicles (up to 1 January 2021) as well as more favourable depreciation write-offs for electric vehicles.

Electromobility in Poland is still in early stages of its development. The government’s plan is to first develop the alternative fuel infrastructure. This is believed to encourage car drivers to switch from their regular cars to electric cars and cars fuelled by hydrogen, LNG or CNG.

v High-efficiency cogeneration

The end of 2018 was a busy time for the Polish legislator. On 14 December 2018, the Act on the Promotion of Electricity from High-Efficiency Cogeneration was adopted. The Act sets forth the rules for providing new support for electric energy generated in high-efficiency cogeneration in cogeneration units. These new support measures are to replace the current support mechanism in the form of certificates of origin from cogeneration.

The Act on the Promotion of Electricity from High-Efficiency Cogeneration provides four support measures in the form of:

- **a** auctions conducted by the President of ERA;
- **b** guaranteed premiums in the amount set by the Minister of Energy;
- **c** individual guaranteed premiums as individually set in a decision issued by the President of ERA; and
- **d** selection system – in the form of individual cogeneration premiums, for units that will win the selection process conducted by the President of ERA.

Each of the aforementioned support measures are designed for different types of cogeneration units (new, existing, modernised, materially modernised). Before obtaining support, all cogeneration units must obtain a decision from the President of ERA allowing the unit to participate in the relevant support scheme.

On 15 April 2019, the European Commission approved the support scheme regulated in the Act on the Promotion of Electricity from High-Efficiency Cogeneration.
vi  Act on Energy Prices

Secondly, the Act on Energy Prices was adopted on 28 December 2018. As prices for emissions allowances and coal have grown, the Polish legislator decided to prevent increases in electricity prices that were expected in 2019. Its plan was to ‘freeze’ the electricity prices in 2019 by setting price caps based on 2018 price caps.

Energy companies trading in electric energy have to establish prices and fees contained in tariffs for 2019 for final customers that are:

a  the prices applicable on 31 December 2018 set forth in the tariff that was approved by the President of ERA; and

b  not higher than prices and fees for electric energy applicable to final customers on 30 June 2018, as set by a given company in a form other than in (a), including in the form of individually negotiated contracts or according to the Public Procurement Law.

Energy prices as set in accordance with the aforementioned rules must be applied from 1 January 2019.

The market participants raised some serious doubts with respect to the compatibility of the Act on Energy Prices with European Union law. Three sets of rules were indicated as having been potentially violated, namely internal electricity market rules, state aid rules and EU ETS.

VII  CONCLUSIONS & OUTLOOK

In 2018, the energy sector in Poland was in the process of significant change and many legislative changes took place this year. This was due to the fact that the Polish government is trying to balance the need for energy security and the need to prevent climate change, to incentivise new investments, and to support existing projects. To fulfil obligations imposed by the European Union regarding the climate change, the Polish government supports investments in renewables and cogeneration by providing state-aid mechanisms for these subsectors. At the same time, it still supports coal-fired power plants, by means of the capacity mechanism.

What should we expect in 2019 in light of the changes that happened in 2018? This coming year will probably be as challenging for the market participants as the previous one, since new developments and amendments in the legislation are currently being prepared, but the outcome of these changes is still to be determined.
Chapter 22

RUSSIA

Thomas Heidemann, Dmitry Bogdanov, Anastasia Makarova and Anna Sivkova

I OVERVIEW

Russia’s vast geography is an important determinant of the economic activity. It has the world’s largest proven natural gas reserves and acts as the largest exporter of natural gas. It is also the second-largest exporter of petroleum. Enormous energy resources let producers generate electricity by thermal, hydro and nuclear power plants and also by using gas, oil and coal.

It is worth noting that revenues from the oil and gas industry make up the bulk of the budget of Russia, therefore government regulation in this area plays an important role in the life of the country.

However, due to global market fluctuations and sanctions recently imposed by the United States, European Union and most European countries, Russia is now seeking new markets for the export of petroleum.

On the other hand, since oil, gas and coal belong to the category of non-renewable natural resources, there is the ongoing process of development of renewable energy sources and their implementation in the Russian energy system. It also falls within the general task of reducing the economy’s dependence on the energy sector, particularly oil and gas, repeatedly declared by the Russian government.

The above trends have also led to the creation and development of the relevant legal framework.

The government regulation in this sphere is generally aimed at creating favourable economic and organisational conditions for the activities of the legal entities.

II REGULATION

i The regulators

In accordance with its Constitution, Russia is a federated state, comprising 85 constituent subjects, that is, regions within the federation. Some powers are vested exclusively with federal authorities, some are jointly exercisable by the federal and regional authorities, and some are used only by the regional authorities. The Constitution also grants some powers to local (municipal) governments at the lowest level, which are formally separated from the system of the state (federal and regional) government bodies.

1 Thomas Heidemann is a partner, Dmitry Bogdanov and Anastasia Makarova are senior associates, and Anna Sivkova is an associate at CMS Russia.
The Russian legal system generally belongs to the continental European legal family. The Constitution, federal laws and regional laws form the foundation of the Russian legal system. Presidential decrees, resolutions of the Russian government and the decisions of various ministries are used as by-laws to support and develop the provisions of primary legislation. Local (municipal) governments are also authorised to enact their own legislative acts, though, they have less importance for energy regulation.

The main sources of legal regulation of the energy industry in Russia are the following.

**General**
- The Law on Natural Monopolies No. 147-FZ dated 17 August 1995.
- The Law on Procedures for Foreign Investment in Companies of Strategic Significance for National Defence and Security of the Russian Federation No. 57-FZ dated 29 April 2008 (the 'Law on Strategic Companies').

**Electricity sector**
- The Law on Electricity No. 35-FZ dated 26 March 2003 (the Law on Electricity).

**Oil and gas sector**
- The Law on Subsoil No. 2395-1 dated 21 February 1992 (the Subsoil Law).

**Renewable energy and energy efficiency**

The regulation powers in the energy industry are mainly concentrated at the federal level. The Russian government is vested with the competence to determine and pursue the state policies and also regulate the economic activities in the whole energy sector, including use of natural resources.

The Federal Ministry of Energy is responsible for implementation of the state policies and regulation in the fuel and energy complex, including electric power, oil extraction and refining, gas, coal, shale and peat industries, major oil, gas and petroleum product pipelines and renewable energy sources. It has the general competence in energy efficiency and heat supply.
The Federal Ministry of Industry and Trade also implements the state policies in the spheres of energy efficiency and use of renewable energy sources but it is mainly responsible for the technical regulation in these areas: adoption of energy efficiency and local content requirements, etc.

The Federal Ministry of Natural Resources and Ecology exercises the state administration in the field of environmental management, protection and safety.

The Federal State Agency on Subsoil Use is in charge of issuance of the licences for subsoil use. It is also responsible for maintaining federal and territorial geological data on subsoil and the state cadastre of deposits.

The Federal Anti-monopoly Service regulates compliance of natural monopoly entities with anti-monopoly requirements. Such natural monopoly areas include:

- production of electric power by generating facilities;
- transmission of electric power via grids;
- providing the services on operational dispatch management; and
- sale of electric power to customers, including end consumers.

Except for generation of nuclear power, no activities relating to production, transmission or sale of electric power require a licence or any other special permit.
However, if the relevant power-generating facility utilises the flammable substances (gas or oil) in the volumes exceeding the established limits, then their operation may be subject to licensing. The same requirement also applies to gas transportation via gas distribution or gas consumption networks with pressure exceeding 0.005MPa.

The relevant licences are issued by the Federal Service for Environmental, Technological and Nuclear Supervision.

Since there are united (national) electricity grid in Russia, electric power transmission services for all major grids are provided by the state-owned joint-stock company Federal Grid Company and its inter-regional and regional subsidiaries. These entities are responsible for operation and development of the Russian united (national) electricity grid.

Other owners of electricity grid facilities can also apply for the grid company status provided that their grids are duly connected to the united (national) grid.

Operational dispatch management services are provided by another 100 per cent state-owned entity – joint-stock company System Operator of the United Energy System. No other companies are permitted to provide the services for operational dispatch management in the electric power sector.

### Oil and gas

Under the Subsoil Law, all natural resources, including oil and gas, are state property and are subject to joint jurisdiction of Russia and the region where the relevant natural resources are located. The Russian law does not provide for any rights of an owner or tenant of the land plot to subsoil under this land plot unless it holds the relevant licence.

According to the Subsoil Law, subsoil plots can be licensed for geological surveys, exploration and extraction of minerals for a fixed term or without any time limit. Depending on their significance, subsoil plots can be either federal or regional. As a general rule, the licences are granted following the tender process.

There are several types of licences:

- for geological exploration and assessment of a subsoil plot;
- for extraction of minerals; or
- a combined licence allowing both geological exploration and assessment of a subsoil plot and subsequent extraction of minerals.

Among other things, the terms and conditions of the licence stipulate the production volume and the payments for subsoil use.

The subsoil user who has been awarded the licence has the exclusive right to use the relevant subsoil plot, provided that it duly follows the requirements set out in the licence.

Breach of the terms and conditions of the licence may result in its suspension or termination.

### iii Ownership and market access restrictions

#### Electricity

Except for generation of nuclear power, there are no special restrictions as to ownership of new or existing power-generating facilities. Therefore, their owners may freely transfer their rights to third parties. However, to access the electric power (capacity) wholesale market, new owners will have to follow the established procedure (see Section IV).
All civil nuclear power-generating facilities in Russia are owned and operated by the state corporation Rosatom, acting through its subsidiary. It is generally prohibited to alienate them to third parties.

As for electricity grid facilities connected to the united (national) grid, their owners may also sell these facilities to third parties but in such case joint-stock company Federal Grid Company, as the entity responsible for operation and development of the Russian united (national) electricity grid, has a pre-emptive right to purchase them.

**Oil and gas**

The ownership of energy assets relating to oil and gas exploration and extraction is subject to specific restrictions.

The Subsoil Law provides for several requirements to the legal entities that are supposed to receive the licence for subsoil use, namely: technical, technological, human resource and financial capabilities.

Some natural resource deposits are subject to special national security restrictions. In terms of oil and gas, these are deposits with reserves of 70 million tonnes of oil or more or reserves of 50 billion cubic metres of gas or more. Acquisitions of shares or indirect control over the companies that hold the licences to subsoil plots of federal significance are subject to significant restrictions (see ‘Transfers of control and assignments’).

The export of oil from Russia is operated by joint-stock company Transneft, the Russian transport natural monopoly, which operates major oil and petroleum products pipelines.

As for natural gas, joint-stock company Gazprom has a monopoly to export natural gas by pipeline. Historically, this monopoly also extended to the export of LNG.

Gazprom, as the owner of the United Gas Supply System, must provide independent gas producers with access to this system, subject only to availability of the required capacity, compliance of the transported gas with established quality and technical parameters, and availability of pipelines to consumers.

**iv Transfers of control and assignments**

Pursuant to the Law on Strategic Companies, the following activities are classified as having strategic significance for national defence and security:

a  geological surveys on subsoil or exploration and extraction of minerals on subsoil plots of federal significance;

b  electric power transmission services;

c  services on operational dispatch management in the electric power sector;

d  transportation of oil and petroleum products by major pipeline;

e  transportation of gas by pipeline; and

f  thermal energy transmission services.

Transactions that result in foreign investors or Russian corporate groups with a foreign element gaining control over a company involved in the above activities (the strategic company) must be cleared by the specifically appointed governmental commission.

The procedure for obtaining the relevant approval is lengthy and cumbersome. However, if it is not obtained for a transaction requiring such approval, the respective transaction is deemed void.
Foreign investors are considered to gain control over the strategic company if they are acquiring directly or indirectly more than 50 per cent of the voting shares in the strategic company (or 25 per cent or more, if the strategic company operates a subsoil plot of federal significance) or otherwise gain effective control over the strategic company.

It should also be noted that certain transactions require post-transaction notification, which must be made within 45 days of the change of control taking effect. One example of this is when foreign investors acquire at least 5 per cent of the shares in the strategic company.

The Law on Strategic Companies further prohibits foreign states, international organisations and organisations controlled by them from gaining control over the strategic company.

It also provides that foreign states, international organisations and organisations controlled by them must obtain prior approval from the Federal Anti-monopoly Service when acquiring directly or indirectly more than 25 per cent of the voting shares in the strategic company (or more than 5 per cent, if the strategic company operates a subsoil plot of federal significance).

Moreover, the foreign investments in the Russian energy sector are also covered by the general restrictions of the anti-monopoly legislation with respect to economic concentration.

III TRANSMISSION/TRANSPORTATION & DISTRIBUTION SERVICES

i Vertical integration and unbundling

*Electricity*

As part of the Russian electric power industry’s complex shift towards decentralised public regulation, the Law on Electricity, as a general concept, determined that economic relations in this sector are based on market mechanisms and competition. At the same time, the Law on Electricity provides for such concepts as energy security and uninterrupted and secure operation of the electric power sector.

As a result, the Russian electricity and capacity market today includes both typical market elements and public regulation mechanisms.

On the one hand, production of electric power in hydropower and nuclear power industries are currently highly concentrated. As mentioned above, there are also natural monopolies in the areas of electric power transmission services and services on operational dispatch management.

On the other hand, many relatively small generating companies, including foreign ones, are admitted to the wholesale market in thermal power generation or renewable energy sectors. And their share is increasing.

*Oil and gas*

There are several vertically integrated joint-stock companies in the oil and gas sector. The major ones are Rosneft, Lukoil, Gazprom neft, Surgutneftegas and Tatneft. There are both privately owned companies (in some cases, with a substantial foreign stake) and state-owned companies among them.

Historically, the concept of vertical integration was used from the beginning of economic reforms in the late 1990s. Now the general structure of the market players is stable. Active foreign investments in the sector are restricted as a result of sanctions imposed by the United States, European Union and most European countries.
ii Transmission/transportation and distribution access

*Electricity*

In Russia, it is declared that any third party is granted non-discriminating access to such services as electric power transmission and operational dispatch management.

Since the above services belong to natural monopolies, the rules of access are generally regulated by the Wholesale Market Rules and have to be followed by both producers and consumers of electric power and operators (owners) of transmission and distribution facilities.

*Oil and gas*

Similarly to the electricity sector, it is declared that any third party may access oil and petroleum product transportation services via major pipelines to consume these products on the Russian domestic market and for their export.

The same also applies to non-restricted access to the gas market and particularly gas transportation and distribution networks.

Since the above transportation and distribution services belong to natural monopolies, the rules of access are generally regulated by the officially established rules that have to be followed by both producers and consumers of oil and petroleum products and gas and operators (owners) of transportation and distribution facilities (i.e., Gazprom for gas networks and Transneft for major oil pipelines).

iii Rates

*Electricity*

As stated in the Law on Electricity, the prices (tariffs) applied by entities providing the electric power transmission services are publicly regulated. The Russian government established the guidelines for pricing and the rules for state regulation of the prices (tariffs) in the energy sector.

According to the established rules, the primarily goal of the pricing is to balance economic interests of producers and consumers of electric power and also ensure return of capital investments. This pricing should also consider requirements and incentives provided by applicable laws on energy efficiency and renewable energy.

The prices (tariffs) may be set either numerically or as a formula or principles of calculation of such prices (tariffs).

To ensure predictability and stability, it is expressly provided that the prices (tariffs), specifically for electric power transmission services, are set on a long-term basis (i.e., for a minimum of 12 months, unless otherwise provided by law or governmental decision.

*Oil and gas*

Oil prices are not regulated in Russia. They are mainly based on current market fluctuations and depend on the rates of applicable taxes and duties.

The Russian government establishes the principles for setting gas prices and tariffs for gas and oil transportation. These principles take into account reasonable expenditures and profits as well as investments to transportation networks. Tariffs may be also differentiated depending on the territories of Russia.
iv Security and technology restrictions

The fuel and energy complex facilities in Russia are subject to both physical protection (against technological accidents, acts of terrorism and other unauthorised intervention) and cybersecurity.

According to the Law on Security of Critical Information Infrastructure of the Russian Federation No. 187-FZ dated 26 July 2017, information and automated management systems, which are used in the energy sector, in the sphere of nuclear energy or in other sectors of fuel and energy industry, are attributed to facilities of critical information infrastructure. Depending on their importance, these facilities must be officially categorised. The owners of these facilities have to elaborate and adopt the internal regulations on providing security of their critical information infrastructure.

Additional requirements are provided to critical facilities of critical information infrastructure. In particular, in these critical facilities it is prohibited:

a to grant remote access to software and hardware to persons who are not employees of the owner;

b to have local non-controlled access to software and hardware to persons who are not employees of the owner; and

c to transfer the information to the developer or manufacturer of software or hardware without control by the owner.

IV ENERGY MARKETS

i Development of energy markets

There is no common market for electric power (capacity) and oil and gas in Russia.

Russia's electricity and capacity sector includes a wholesale market and a retail market for electric power and capacity.

The wholesale market's participants are large producers and customers of electricity and capacity.

Different from the wholesale market, the retail market resells electricity to end consumers, generally at publicly regulated tariffs.

The Wholesale Market Rules, among other things, set out the procedure for accessing the wholesale market as well as the wholesale market operation concepts.

The main concepts of the wholesale market operation include:

a free non-discriminatory access to the wholesale market for all electricity sellers and customers;

b free choice by the wholesale market's participants for the method of electricity sale and purchase;

c accounting specifics for certain wholesale market participants; and

d obligatory purchase of capacity by the wholesale market participants when required by the Russian government.

As for oil and gas markets in Russia, they can be subdivided into the domestic market and export market.
ii Energy market rules and regulation

Electricity

As mentioned above, the wholesale market is regulated by the Wholesale Market Rules. The Russian government further determines zones (territories of Russia), where market prices or regulated tariffs must apply, including technologically isolated zones that are not connected to the Russian united electricity grid.

Oil and gas

The gas market in Russia is generally regulated by the Rules of Gas Supply adopted by the decree of the Russian government No. 162 dated 5 February 1998. These Rules govern relations between suppliers and purchasers of gas, including gas transportation and distribution companies.

In the gas supply sphere, the state pricing policy is designed to:

a create favourable conditions for seeking, exploring and developing gas deposits, extracting, transporting, storing and supplying gas;
b expand the sphere of application of market prices to gas;
c exercise control over application of state regulated prices (tariffs) in the gas supply sphere;
d reimburse the organisation owning the gas supply network for gas payment debts incurred by non-disconnectable consumers;
e encourage use of gas as a motor fuel; and
f ensure the competitiveness of Russian gas on the world energy market.

iii Contracts for sale of energy

Electricity

According to the Wholesale Market Rules, the large suppliers and customers of electricity and capacity, as a condition to accessing the wholesale market, must enter into a contract for connection to the trade system of the wholesale market, and thus become members of a self-regulating organisation of wholesale market participants (the Market Council).

The main goals of the Market Council are to maintain a balance of interests among the wholesale market participants, and ensure the integral operation of its commercial infrastructure. In pursuing these goals, the Market Council, among other things, keeps a register of the wholesale market participants, sets out the wholesale market regulations and standard forms of contracts used by its participants, and monitors so that participants comply with these regulations and contracts.

In addition, an important role in the wholesale market is played by organisations that provide it with technological and commercial infrastructure. One such infrastructure organisation is a commercial operator that is noted specifically for its activities to arrange for trade on the wholesale market. In particular, it holds tenders, and registers electricity and capacity sale and purchase contracts made on the wholesale market.

The existing wholesale market consists of a number of segments, each of which has its own terms and conditions of entry into electricity sale and purchase contracts.

For instance, in the regulated contracts segment, electricity is sold at set tariffs and the commercial operator selects, at its discretion, suppliers and customers that are required to enter into a relevant electricity supply contract.
This method largely applies where electricity is sold to the general public. This segment also covers the sale of electricity generated with renewable energy sources, in which case tariff rates are based on the localisation level of the relevant generating facilities.

On the day-ahead spot market, electricity sale and purchase contracts are based on the equilibrium price determined by the commercial operator, which compares and selects the competitive price bids submitted by suppliers and customers.

Finally, in the non-regulated electricity segment, contracts are made between suppliers and customers by terms negotiated between them (including the price and scope of supply).

A separate part of the wholesale market is the capacity market, where suppliers provide their customers with a fee-based right (and often an obligation) to enter into future contracts for the purchase and sale of certain volumes of electricity.

The created capacity market facilitates issues such as the financing of new generating facilities, compensation for electricity producers’ fixed costs, and ensuring electricity supply reliability and security.

As in the case of the electricity sale and purchase market, contracts made on the capacity market may be either regulated or non-regulated.

Oil and gas
Gas is supplied on the basis of agreements between suppliers and consumers in accordance with the general civil laws and the rules approved by the Russian government for gas supply and use of gas in Russia.

The pre-emptive right to conclude gas supply agreements is enjoyed by the purchasers of gas for state and municipal needs, utility, domestic and social needs of the people.

Market developments

Electricity
The Russian electricity and capacity market today is a complex structure that consists of both typical market elements and public regulation mechanisms. The main problem with the existing system is low competition, owing to, on the one hand, the need for the smooth and reliable operation of the electric power sector and, on the other, the relatively small number of electricity and capacity sellers on the wholesale market.

New incentives are currently being sought for more competition on the market, particularly, by increasing the sales of electricity (capacity) produced using renewable energy sources.

Oil and gas
According to the Energy Strategy of Russia for the period up to 2030 adopted by the decree of the Russian government No. 1715-r dated 13 November 2009, the main goal in the oil and gas sector is to diversify the export markets away from the core European market to prospective eastern markets, and to develop oil and gas production and energy infrastructure in the northern Arctic, east Siberia and the far east of Russia. Another objective is to develop and deliver the LNG.
V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

After years of being considered an 'oil-and-gas country', the Russian government decided to develop a renewable energy sector and promote renewable energy projects in the country.

The legal framework for this progress was set up in 2009. The Russian government approved the State Policy on Energy Efficiency (the Policy), and subsequently adopted the National Strategy for the Development of Renewable Energy. Both documents became the basis for adopting more specific regulation establishing this new legal regime.

By this new legal regime Russia replaced the 'premium scheme', where the Russian Government had proposed to motivate market players through premium payable to them, with the 'capacity supply scheme'.

The capacity supply scheme implies a predetermined price paid to the capacity supplier which is based on the beneficial tariff. The supplier who met the Russian localisation requirements can use this beneficial for 15 years and thus receive the guaranteed return on the investment used for building and operating a renewable energy generating facility with a 12–14 per cent margin.

The existing legal regime applies to solar, wind, moderate-sized hydro and waste treatment power sources generating more than 5MW of renewable power.

The capacity volumes are offered to potential suppliers at annual tenders, which are conducted by the Market Council for each type of power-generating facility: photovoltaic, wind and water energy. In 2017, the procedure was extended to waste-burning energy sources.

The winners of each tender conclude long-term energy supply agreements (CSAs), under which a capacity supplier must build its renewable-energy-generating facility and put this facility into operation by a certain date defined in the CSA. The capacity should then be supplied to the Russian power system, where large industrial consumers are obliged to buy it. A mandatory CSA form is approved by the Russian government and cannot be renegotiated by the potential supplier.

Failure to meet the deadline for implementation of the renewable energy project indicated in the respective CSAs may lead to a significant contractual penalty.

The Policy covers the period until 2024 with the goal of ensuring that the share of renewable energy reaches 4.5 per cent in the entire energy sector. During 2018 and 2019, tenders of 95 per cent of the targeted power generation capacity in the solar and wind sectors have been awarded to the potential suppliers. Therefore, the renewable energy market awaits the new regulations that will govern its activities after 2024.

The current framework has raised many controversies. Large industrial consumers have objected to the extension of the Policy, instead calling for the adoption of alternative measures to support the renewable energy sector. The main reasons for their dissatisfaction are the price of the power capacity and the increase in the costs of implementing the renewable energy projects. However, the key investors of the Russian renewable energy sector (such as Rusnano and Renova) have requested the extension of the Policy until 2035. These companies believe the Russian renewable energy sector is still too young to function under the general competitive rules of the Russian energy market applicable to other sectors.

While the outcome of this dispute is still not clear, the Market Council initiated development of the concept of Russian green certificates, which may be used to supplement the existing structure. Work is being done by the Market Council in this respect; thus, for the first time in Russian history, the concept of Russian green certificates is starting to seem
a workable option. By selling these green certificates, consumers could reduce their total amount of payments for capacity under the current support mechanism of CSAs, while for the power suppliers, the green certificates could act as a source of return on their investments.

Consequently, the Russian renewable energy market is now waiting for future changes in the legal regime. Such changes will certainly give a new impulse to further development in the industry.

ii Energy efficiency and conservation
The Energy Efficiency Law created a legislative, economic and organisational stimulus for energy saving and increasing energy efficiency.

To facilitate the efficient use of energy resources and to support and encourage energy saving, the Energy Efficiency Law provides for several groups of energy efficiency requirements applicable to various sectors, notably including the construction and the public sectors. For instance, energy consumption reduction targets are set for publicly financed institutions. Moreover, companies with state participation and companies carrying out regulated types of activities are also obliged to adopt and implement programmes aimed at increasing energy efficiency.

According to the Energy Efficiency Law, commercial companies may carry out the voluntary energy audit. This audit is aimed at:

\[ a \] collecting objective data on the volume of energy used;
\[ b \] defining energy efficiency indicators;
\[ c \] defining the energy saving potential and increasing energy efficiency; and
\[ d \] developing and evaluating a list of possible programmes which target energy efficiency increase.

The results of the energy audit must be reflected in an energy passport comprising information on the presence of energy meters, the volume of energy used and the variation of such volumes, etc. Copies of energy passports are forwarded to the Federal Ministry of Energy, which is responsible for processing, systematising and analysing the information contained in these passports.

Instead of energy audits, state and local authorities, as well as state-owned and municipal institutions, have to submit annual declarations of electric power consumption.

In order to encourage private investors to participate in the energy efficiency programme, the Energy Efficiency Law proposes a range of financial and tax incentives. Such incentives for commercial companies include, in particular:

\[ a \] investment tax credits of up to 100 per cent for companies investing in energy efficiency and energy saving technology;
\[ b \] accelerated depreciation of assets categorised as having high energy efficiency or assets classified in the top energy efficiency class (the qualifying assets);
\[ c \] three-year corporate property tax exemption on newly accounted for qualifying assets; and
\[ d \] partial compensation of interest on loans granted by Russian banks for the purpose of investing in energy saving and more energy-efficient technology.

iii Technological developments
Setting up a new legislative basis and further efforts taken to implement the Policy brought complex technologies to the Russian renewable energy sector.
Russian localisation rules, aimed at the development of local production in the renewable energy sector, significantly impact the economics of the projects. These rules stipulate that a certain percentage of the elements and spare parts of the energy-generating facility are to be produced in Russia in order to apply a beneficial capacity price. The potential supplier must commit to a certain degree of localisation when bidding and, if this level has not been reached, the beneficial tariff shall not apply and the capacity price will be significantly lower.

To meet the above requirements, global Russian corporations involved in renewable energy projects usually create joint ventures with large foreign technology owners and local companies. The local partner is usually responsible for handling local issues of the renewable energy projects that may arise during the construction and operation of the generating facility. The use of such joint venture structures enables the creation of a strong team that can effectively support the implementation of the renewable energy project.

VI THE YEAR IN REVIEW

Similarly to previous years, the energy market in Russia, especially the export side, has been developing in 2018 under the pressure of US and EU sanctions that restrict access of the Russian oil and gas companies to foreign investment and technology. It has encouraged these companies to seek cooperation with investors from the Middle East and China.

After a tremendous boost in 2016–2017, the renewable energy market (mainly, wind and solar photovoltaic) has continued to increase its share in the energy sector with the aim of reaching 4.5 per cent by 2024.

New LNG treatment and distribution facilities have been commissioned in the northern regions of Russia.

VII CONCLUSIONS & OUTLOOK

It is difficult to overestimate the importance of the energy sector in the Russian economy.

Traditional industries such as oil and gas, as well as power generation by thermal (coal), hydro and nuclear power plants continue to be the basis of both economic development and national security.

On the other hand, these industries are highly affected by the current political tensions in international relations between Russia and other countries.

In response to US and EU sanctions, Russia’s local content requirements have become one of its main economic policy drivers supporting inbound investments and technology transfers to develop local innovative technologies, including in the renewable energy sector.

We expect further development of the Russian energy sector. However, the relatively high level of uncertainty may lead to a search for new alternatives and opportunities.
Chapter 23

SOUTH AFRICA

Lido Fontana and Sharon Wing

I  OVERVIEW

The year 2018 brought with it immediate change and a positive turnaround in the South African energy sector. One of the major stand out developments was the updated Integrated Resource Plan (IRP) (as discussed below), which was released for public comment during August 2018. This plan provides for a dynamic energy mix which outlines South Africa’s national energy roadmap and is a great improvement to the former IRP which was approved by Parliament in December 2017 and sent back for processing for reasons not disclosed. During 2018 there were announcements made by the Minister of Energy, that South Africa would launch a fifth Renewable Energy Independent Power Producer Procurement Programme (REIPPPP) that would include a further 1800MW to the grid during November 2018. However, this has yet to come to fruition as many believe the stagnation of the launch of the bid 5 window is result of state-owned utility, Eskoms instability and financial woes and the updated IRP not yet being signed into law.

April 2018 marked the signing of the long-awaited 27 independent renewable energy agreements with a combined investment value of 56 billion rand and a combined capacity of 2,300MW from bid windows 3.5 and 4 of REIPPPP. This brought renewed hope from independent power producers and boosted investor confidence. Further, Eskom announced during 2018 that it is preparing to roll out 360MW battery energy storage systems financed by the African Development Bank and the World Bank that will consist of supplying, installing and operating distributed battery storage infrastructure at Eskom sub-stations including sub-stations located at existing variable renewable energy plants operated by Eskom Renewables (including the Bank-funded 100MW Sere wind farm), upcoming distributed solar PV to be implemented by Eskom Distribution, and the new REIPPPP sites.

South Africa supplies 40 per cent of Africa’s electricity through the Southern African Power Pool and other arrangements. Although South Africa owns the fifth largest recoverable coal reserves in the world (estimated at 66.7 billion tons), at mid-2018, the Minister of Energy confirmed that a total of 91 renewable projects had been connected to the grid with a capacity of 63,000MW. This has brought the total investments in renewable energy to approximately 201.8 billion rand under the REIPPPP. South Africa’s five largest renewable energy projects are multibillion-rand wind farms that contribute a collective 645,71MW to the grid with 6,360MW of wind power being determined for procurement by IPPs.

However, in 2018 South Africans were also hit by rolling blackouts implemented to protect the grid from total collapse or black out. The reasons for the lack of energy capacity

1  Lido Fontana is of counsel and Sharon Wing is an associate at Covington & Burling (Pry) Ltd.
is Eskom’s poor management, the lack of funding or misappropriation of funds, and maintenance and labour issues. Further, the expensive and overdue operation of Medupi and Kusile coal-fired plants have resulted in severe pressure on the national grid with not enough reserve margin from generating assets to meet peak demand, and the government of South Africa being forced to consider the unbundling of Eskom. This will result in Eskom being unbundled in three divisions – generation, transmission and distribution – which will positively end Eskom’s monopoly but will cost millions in taxpayer money to implement.

The Minister of Energy also confirmed that the Khanyisa and Thabametsi coal-fired power stations (these projects will add approximately 863MW to the national electricity once operational and are South Africa’s first privately owned coal-fired power plants) must implement the latest technology to reduce harmful emissions as a reaction to continued court actions regarding the projects’ climate impact.

Unfortunately, there have been no noteworthy developments following the expressions of interest by the South African government during 2016 in relation to the proposed 600MW gas-fired power project alongside one or more state-owned companies. Moreover, the South African government is still at work to draft regulations that ensure the exploration of shale gas does not harm the environment (shale gas only makes up 3 per cent of the total primary energy supply in South Africa). This is due to increased interest in shale gas and the US Energy Information Administration (EIA) confirming that the South Africa is ranked eighth in terms of technically recoverable shale gas resources in the world. South Africa’s plans in respect of further nuclear power stations also appear to be on hold, given the amendments to the updated IRP where nuclear may only be expected to be introduced in 2030.

II REGULATION

The regulators

In South Africa, energy regulation is split among three regulators:

a. the National Energy Regulator (NERSA), established under the National Energy Regulator Act 2004, which regulates electricity, piped gas and petroleum pipelines industries;

b. the National Nuclear Regulator (NNR), established under the National Nuclear Regulator Act 1999, which regulates nuclear energy; and
c. the Petroleum Agency of South Africa (PASA), established under the Mineral and Petroleum Resources Development Act 28 2002 (MPRDA), which regulates petroleum exploration and production.

Each of these Acts, together with other key legislation regulating the relevant industry (the Electricity Regulation Act 2006 (the Electricity Regulation Act) in the case of electricity; the Petroleum Pipelines Act 2003 in relation to the petroleum industry; the Gas Act 2001 (the Gas Act) as regards piped gas; the Nuclear Energy Act 1999 in the case of nuclear energy; and the MPRDA in respect of petroleum exploration and production) establish the framework for energy regulation in South Africa. That legislation, together with regulations, notices, rules and guidelines issued thereunder grant expansive regulatory power to the regulators, including the powers to issue, amend and revoke licences, as well as to approve tariffs.
Regulated activities

Under the Electricity Regulation Act, a licence is required for the operation of each of electricity generation, transmission and distribution facility and in respect of the import, export and trading of electricity (collectively, the Licensed Activities). That Act provides exemptions for licences in respect of (1) any generation plant constructed and operated for demonstration purposes; (2) any generation plant constructed and operated for own use; (3) any non-grid connected electricity supply other than for commercial use; and (4) any other activity relating to the Licensed Activities in respect of which NERSA has determined that a licence is no longer needed. In relation to the last referenced exemption, NERSA may require that persons undertaking such activities nevertheless register the activities with NERSA.

A person obliged to hold a licence in terms of the Electricity Regulation Act must apply to NERSA for the licence in the form and applying the procedure prescribed. The application must be accompanied by the prescribed licence fee. The information required to form part of such an application includes, among other things: (1) a description of the applicant, including the vertical and horizontal relationships with other persons engaged in the operation of the relevant Licensed Activity; (2) the administrative, financial and technical abilities of the applicant; (3) a description of the proposed generation, transmission or distribution facility to be constructed or operated; (4) a detailed specification of the services that will be rendered under the licence; (5) a general description of the type of customer to be served; (6) the tariff and price policies proposed to be applied; and (7) evidence of compliance with the Integrated Resource Plan. The process entails publication of notices of the application in appropriate newspapers or other media, the applicant responding to objections to the application being granted, and culminates in NERSA making a decision on the application within the prescribed period.

In terms of the National Nuclear Regulator Act 1999, no one is allowed to procure a site, construct, operate, decontaminate or decommission a nuclear installation except under the authority of a nuclear installation licence. The process prescribed for the making, consideration and issue of such licences is similar to that outlined above, albeit that the time lines are shorter and an applicant may further be directed to serve a copy of its application upon every municipality affected by the application and such other body or person as the chief executive officer of the NNR determines.

Licences are also required for the storage, transportation and reticulation of gas and petroleum through petroleum pipelines. The licences for the storage, transportation and reticulation of petroleum through pipelines are issued by NERSA. Although the procedure for applying for the licences is similar to that of Licensed Activities, only owners of storage, transportation and reticulation facilities respectively, may apply for licences for the storage, transportation and reticulation of petroleum.

Licences for exploration or production rights in petroleum resources are generally issued pursuant to bidding processes initiated by the Minister of Mineral Resources. The Minister invites applications for exploration and production rights in respect of designated blocks on predefined terms and conditions. Successful applicants are still required to submit applications to PASA for a reconnaissance permit, technical cooperation permit, exploration right or production right. In certain instances, the Minister will upon consideration of PASA’s recommendations either grant or refuse the application. In the event that the application

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2 Section 10(2)(a)–(h) of the Electricity Regulation Act, 2006.
3 Section 73(1) of the MPRDA.
is granted, the exploration right or production right must be registered with the Mineral and Petroleum Titles Registration Office, while the permits must be filed and noted with the Mineral and Petroleum Titles Registration Office. The rights issued by the Minister of Minerals Resources only constitute limited real rights. 

iii Ownership and market access restrictions

In 2010, much of South Africa’s electricity generation capacity was state-owned. At that stage, Eskom, a state-owned utility with a monopoly over the national transmission grid produced close to 95 per cent of the country’s electricity, while the balance of the country’s electricity was sourced mainly from municipalities. Like electricity generation, transmission and distribution capacity was restricted to the state and state-owned entities.

In 2011, the South Africa government launched the Integrated Resources Plan, which called for the doubling of the country’s electricity capacity from its 2010 level of 238,272 GWh using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, including large-scale hydro to be imported from other countries in the southern African region.

The REIPPPP has served as the primary vehicle through which the South African government has procured renewable energy from private sector power producers. The bid window 4 under the REIPPPP programme provided that projects developed thereunder must be 40 per cent owned by South African citizens with people of colour holding a minimum of 12 per cent (with a target of 30 per cent), and a minimum of 2.5 per cent ownership by local communities (those communities within a 50km radius of the project). In addition to the ownership requirements, REIPPPP bidders are also required to bid on other non-price factors known as ‘economic development requirements’, which are designed to achieve the government’s Integrated Resource Plan objectives of promoting job growth, domestic industrialisation, community development and black economic empowerment (a programme designed to counter the adverse economic impacts of apartheid by initiating, among other things, ownership and control of capital by South Africans of colour, women and disabled persons (Historically Disadvantaged Persons or HDSA), as well as skills transfer and enterprise development of legal entities owned by HDSAs).

The Coal Baseload IPP Procurement Programme provides that 51 per cent of each project must be owned by South Africans and 30 per cent must be black ownership. Ownership criteria for the gas-to-power and nuclear procurement is still unknown. Save as outlined above, there are no foreign ownership or aggregate holdings constraints under the REIPPPP and the Coal Baseload IPP Procurement Programme.

The preliminary information memorandum (PIM) for the Liquefied Natural Gas to Power Independent Power Producer Procurement Programme (LNG-to-Power IPP Procurement Programme) was released on 4 October 2016 by the DOE. The PIM provides insight into the proposed LNG-to-Power IPP Procurement Programme and provides the basic framework being considered by the DOE for the minimum mandatory socio-economic objectives, all of which will be provided in further detail under the request for qualifications (RFQ), which was meant to be issued during November 2016. To date, the RFQ has not been issued and in all probability the RFQ will only be released once the DOE has finalised the contentious updated Integrated Resource Plan, which was released for public comment in December 2016 and was extended to 31 March 2017 (discussed below).

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4 Section 5(1) of the MPRDA.
The Petroleum and Liquid Fuels Charter, issued under the MPRDA provides a framework for black economic empowerment within that industry. Holders of exploration and production rights are obliged to reserve shareholdings for HDSAs in their respective companies. Companies active in the upstream sector are obliged to reserve participation interest of not less than 9 per cent for HDSAs, while companies in the midstream and downstream sectors must reserve a 25 per cent participating interest for HDSAs. These companies must further make contributions towards the funding of skills development initiatives.

iv Transfers of control and assignments

Transfer of control and the assignment of a licence issued in respect of Licenced Activities, including generation licences issued to IPPs, are restricted by conditions imposed on the licensee by NERSA.\(^5\) Accordingly, each licence must be reviewed on a case-by-case basis to determine what specific approvals are required for its transfer. However, the Electricity Regulation Act generally provides that a licensee may not cede or transfer its powers or duties under a licence to any other person without the prior consent of NERSA. The transfer of control and the assignment of licences issued to IPPs are further regulated by the Implementation Agreement between the South African DOE and the IPP; that agreement provides for, inter alia, government support for the development and financing of relevant IPP projects.

A nuclear licence is not transferable in terms of the National Nuclear Regulator Act 1999.

Regarding the transfer of control and the assignment of a licence or permit in the petroleum sector, the position is as follows: (1) a reconnaissance permit is not transferable, nor does it grant the holder any exclusive right; (2) a technical cooperation permit is not transferable, but the holder of the right has an exclusive right to apply and be granted an exploration right over the area described in that permit; (3) an exploration right is transferable and the holder has an exclusive right to apply for and be granted a renewal of the right, or for a production right, over the area described in that exploration right; and (4) a production right is transferable and the holder has an exclusive right to apply for and be granted a renewal of that production right.

The consent of the Minister of Mineral Resource must be obtained in the event that a holder wishes to cede, transfer, let, sublet, assign, alienate or otherwise dispose of a prospecting right or exploration right or interest in such a right, or a controlling interest in a company that holds such a right (except in the case of a change in controlling interest in a listed company). An application for the Minister’s consent must set out and prove that the transferee has the required technical and financial ability to comply with the obligations imposed on the holder of the exploration or production right.

A licence granted to a person or entity under the Gas Act may not be assigned to another party, is valid for a period of 25 years and may be renewed after the expiry of the licence period.

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\(^5\) Section 15(1)(k) of the Electricity Regulation Act, 2006.
III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity

The Independent System and Market Operator (ISMO) Bill was introduced in 2011. The ISMO Bill intended to restructure the electricity supply industry by providing for the establishment of the ISMO as a state-owned company autonomous from Eskom to serve as the dedicated procurer of electricity for onward sale to wholesale off-takers. The ISMO Bill, when established would have removed the operation of the transmission grid from Eskom and allow for easier access to the grid by IPPs.

However, the ISMO Bill was suddenly withdrawn in its final stages of being adopted by its sponsor, the DOE, in June 2015.

In 2015, the government had apprised the market that a new ISMO Bill was being drafted; however, a draft has not yet been released for public comment. However, the Democratic Party (the opposition party to the African National Congress) announced during 2018 that it seeks to introduce an ISMO Bill to Parliament and tabling it at the National Assembly. The Bill seeks to bring an end to the Eskom monopoly, by unbundling Eskom into different divisions.

Gas

The gas pipeline network comprises the Rompco Pipeline (used to transport gas from Mozambique into South Africa), which is the main pipeline network in South Africa, and several other short-range pipelines, which are privately owned. Owners of these pipelines are compelled under their licence conditions to grant access to third parties on commercially reasonable terms only to the extent that they have uncommitted capacity in these transmission pipelines.

ii Transmission/transportation and distribution access

The transmission of electricity is currently being undertaken exclusively by Eskom. Save for contractual commitments under wheeling agreements with Eskom, there is no obligation on Eskom to provide third-party access to the transmission grid. Eskom distributes electricity directly to customers and to municipalities, who redistribute the same (see Section IV on energy markets, below).

There is currently no regulated framework for use-of-system charges for embedded generators. Some of these generators (primarily IPPs) sell to Eskom through approved power purchase agreements, while others wheel energy to third parties through bilateral agreements with Eskom.

Generators that wish to wheel energy face a number of challenges, including the charges involved, which may render small projects uneconomical; the generator being required to obtain a licence from NERSA to generate and for the wheeling transaction; the generator having to comply with Eskom’s onerous requirements for grid connection; and entering into multiple agreements with various distributors.

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6 This is a joint venture between South African Gas Development Company Limited (iGas), Companhia Limitada de Gasoduto (CMG) and Sasol Gas Holding Proprietary Limited.
Although Eskom has provided guidelines on its website for wheeling costs on its network, it still remains a complicated process. NERSA has said that it is currently working on developing a standardised framework for these arrangements.

The Gas Act provides that a licensee of a gas transmission pipeline must provide access to its transmission pipelines to third parties, while the Petroleum Act provides that a licensee of a petroleum pipeline must provide access to its loading facilities and uncommitted capacity in storage facilities to third parties. These requirements will be provided as conditions on a licensee’s licence. However, a distributor is not compelled to grant access.

iii Rates

Electricity

Eskom’s tariffs are regulated by NERSA under the Electricity Regulation Act. These tariffs are based on Eskom’s costs plus a reasonable rate of return.

A suite of supply policy guidelines for the integrated national electrification programme (INEP) was last updated on 26 November 2018 by the DOE (the integrated national electrification programme’s provides that the DOE is responsible for assisting municipalities with funding of implementation of electrification projects in order to achieve universal access to electricity by 2025 and is one of the pillars of the South African government’s energy transformation strategy, born in the 1998 White Paper on Energy Policy).

The objective of the policy guidelines is to develop and provide a suite of supply frameworks in line with the 1998 White Paper Policy and guidelines, thus providing a uniform set of standardised supply options and connection fees, as well as a uniform approach to electrification tariffs for electrification customers for all licensed entities providing electricity.

Oil and gas

In relation to gas and piped petroleum product, tariffs are negotiated on a commercial basis and then approved by NERSA.

The DOE is mandated to regulate the tariffs applicable to the manufacturing, wholesaling and retailing of petroleum products through the implementation of the Petroleum Products Act 1977 and the responsibility resides with the Controller of Petroleum Products (this is too wide a matter to be discussed in this chapter).

iv Security and technology restrictions

South Africa’s nuclear legislation, which is based on several international conventions to which South Africa is a party, provides for the establishment of internationally endorsed protocol on nuclear safety, political and financial risk and ultimate state liability. The NNR is mandated to provide for the protection of persons, property and the environment against nuclear damage as the competent authority for nuclear regulation in South Africa.

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7 www.eskom.co.za/Whatweredoing/Pages/Wheeling_Of_Energy.aspx.
8 Nuclear Energy Act 46 of 1999.
9 For example, the Convention on Nuclear Safety, 1994; the Convention on Early Notification of a Nuclear Accident, 1986; the Convention on Assistance in the Case of Nuclear Accident or Radiology Emergency, 1986; the Convention on Physical Protection of Nuclear Material, 1979. See also: www.nti.org/treaties-and-regimes/treaties/.
The NNR has regulatory requirements developed in accordance with the National Regulator Act, the South African Nuclear Energy Policy (2008), Minimum Information Security Standards and IAEA Nuclear Security Series No. 7. The IAEA Nuclear Security Series No. 7 is the International Atomic Energy Agency implementing guide on Nuclear Security Culture, which prescribes characteristics, attitudes and behaviour of individuals, organisations and institutions in supporting the establishment of effective nuclear security. The development of the regulatory requirements is to assure nuclear security or physical protection systems at nuclear installations or associated actions in South Africa.10

Several of Eskom’s power stations and other facilities, as well as municipality distribution installations, have been designated national key points. National key points are strategic installations, which require heightened state security.

IV ENERGY MARKETS

i Electricity

NERSA is mandated to, inter alia, regulate trading activities such as electricity resale (buying and selling). Eskom purchases electricity that is supplied by IPPs to the national grid and in turn sells the electricity to industrial, mining, commercial, agriculture and residential customers in South Africa, some members of the Southern African Development Community and redistributors (municipalities), who in turn redistribute electricity to businesses and households within their areas.

Section 155(6)(a) and (7) Schedule 4B of the Constitution11 lists electricity reticulation as a competence of municipalities in South Africa. Each municipality is a service authority for the electricity reticulation function for the whole of its jurisdictional area and has the right to set tariffs in respect of its sale of electricity in its areas of jurisdiction. On 30 October 2014, the South African Local Government Association entered into a memorandum of understanding and active partnering agreement with all distributors, including Eskom, to ensure cooperative and collaborative working relationships.

Electricity can also be onsold to multiple customers by persons with bulk supply points, such as bodies corporate and office parks (known as Resellers). These Resellers are ‘non-licensed traders’ of electricity in terms of the Electricity Pricing Policy.12 Resellers are not required to hold a distribution licence, but they must be registered with the licensed authority (generally a municipality) from which the bulk connection was obtained.

To resell electricity the licensed authority must complete a service level agreement with the Reseller to operate in its area of jurisdiction. The Reseller is also obligated to supply its customers with information on tariffs and tariff structures.

South Africa is part of the Southern African Power Pool (SAPP), which includes several Southern African utilities and supplies to the following neighbouring countries being Zimbabwe, Lesotho, e Swantini, Namibia, Botswana, Mozambique and Zamia. While SAPP faces a number of major challenges such as lack of maintenance of infrastructure, high

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10 www.nnr.co.za/nuclear-security/

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transmission losses and limited funds to finance new investments, the energy volumes traded by Eskom since its inception in 1996 (around 4,500GWh) have increased steadily to over 9,977GWh a year since 2003.\footnote{www.energy.gov.za/files/esources/electricity/electricity_powerpool.html.}

\section*{ii Natural gas}

The use of natural gas as an energy source has stagnated; however, the government of South Africa is optimistic that natural gas will form the backbone of regional economic integration amount South African Development Community member countries.

\section*{Shale gas}

The mineral resources manager announced that it was the departments intention to fast-track the finalisation of exploration rights application. However, such applications are yet to be finalised.

\section*{600MW gas}

No new developments have been made in relation to the expression of interest, which closed on 20 June 2016 for the Gas 600MW IPP Procurement Programme. However, a feasibility study by NOVA Energy, a South African integrated natural gas company, has been initiated to assess the conversion of the Kelvin power station from a 450MW coal-fired power plant to a 600MW gas-fired power station.

\section*{iii Gas pipeline}

A cooperation agreement has been signed with investors in respect of a 2,600km gas pipeline from the Rovuma Basin in northern Mozambique to Gauteng province in South Africa with an estimated value of US$6 billion.

\section*{iv Nuclear}

The development of nuclear power in South Africa has slowed as a result of the updated Integrated Resource Plan (IRP) reporting that the introduction of nuclear energy will only be considered from 2030 onwards.

\section*{V RENEWABLE ENERGY AND CONSERVATION}

\section*{i Development of renewable energy}

\subsection*{Background}

The South African energy sector has undergone extensive transformation in recent years. In August 2011, the government’s DOE launched the REIPPPP, an unprecedented, world-class procurement programme with the audacious goal of the country producing 17,800MW of renewable energy by 2030. This objective was set against a backdrop of the country’s then current generation capacity becoming increasingly inadequate to meet the ever rising electricity demand of a growing economy. The inadequacy manifested in Eskom, with a monopoly over generation and transmission capacity, implementing rolling blackouts throughout the
country in late 2007 and early 2008. Rolling blackouts resurfaced in 2014 and early 2015. Although widespread load-shedding has not occurred since September 2015, consumer trust in Eskom’s ability to deliver reliable power supply is conditioned on a wait-and-see approach.

After the electricity blackouts in 2008, the country decided to draw investor interest by initiating a process to introduce renewable energy feed-in-tariffs (REFIT) to facilitate the introduction of renewable energy into the power system. In 2009, NERSA published REFITs with proposed tariffs designed to cover generation costs plus a real after-tax return on equity of 17 per cent, fully indexed for inflation.

However, in 2011, NERSA terminated the REFIT programme because the National Treasury was of the opinion that the REFIT approach contravened public finance and procurement regulations. The REFIT programme was subsequently terminated and replaced by the REIPPPP.

The IRP

The initial IRP sets out the South African government’s strategy for the establishment of new generation and transmission capacity for the country for the period 2010 to 2030. It calls for the doubling of the country’s electricity capacity from its 2010 level of 238,272GWh, using a diverse mixture of energy sources, mainly coal, gas, nuclear and renewables, and including large-scale hydro to be imported from other countries in the southern African region. The initial IRP further details how this demand should be met in terms of generating capacity, type, timing and cost. The initial IRP also serves as an input to other government planning functions, inter alia, economic development, funding, environmental and social policy formulation. It is also a process by which the requirement for further investment in electricity generation capacity for South Africa is determined.

At the time that the IRP was initially promulgated, the South Africa government advised that the IRP should be viewed as a ‘living plan’ that would be revised by the DOE every two years to ensure its relevance with regard to (among other things) technological and environmental developments in the global arena. An update to the IRP was provided for public comment in August 2018; however, this document has not yet been submitted to cabinet for approval. Although the Minister of Energy released a draft of an updated Integrated Energy Plan (IEP) on 2 November 2016, a subsequent draft has not been provided for public comment. The IEP serves as the government’s master plan for the entire energy system, with its focus on the broader objective of reducing the overall energy intensity of the country. The IEP regulates energy industries and promotes electric power investment, greater employer benefits and more favourable environmental impact. The IRP, on the other hand, being subordinate legislation to the IEP, focuses specifically on electricity.

It became a necessity to revise the initial IRP due to capacity additions through Ministerial Determinations14 under Section 34 of the Electricity Regulation Act15 and update key assumptions that have changed significantly since the promulgation of the initial IRP. Accordingly, the updated IRP provides for the following new additional capacity by 2030: 1,000MW of generation from coal; 2,500MW from hydropower; 5,670MW from photovoltaic (PV), 8,100MW from wind and 8,100MW from gas. This will result in the installed capacity mix in year 2030 consisting of: 34,000MW from coal (46 per cent);
1,860MW from nuclear sources (2.5 per cent); 4,696MW from hydropower (6 per cent); 291MW from pump storage (4 per cent); 7,958MW from PV (10 per cent); 11,442MW from wind (15 per cent); 600MW from concentrated solar power (1 per cent); and 11,930MW (16 per cent) from gas.

**What is the Independent Power Producer Procurement Programme?**

The Independent Power Producer Procurement Programme (IPPPP) was introduced as a vehicle for securing private sector investment for the development of new electricity generation capacity. The 1998 White Paper on Energy Policy identified that IPPs were expected to play a key role in developing and producing new electricity capacity in the country.

The REIPPPP was initiated with a request for proposals in August 2011, in terms of which IPPs were invited to bid in a competitive process.

**VI THE YEAR IN REVIEW**

**i Amendment to the MPRDA**

The Mineral Petroleum Resources Amendment Bill [B15D – 2013] (MPRDA Bill) was submitted to Parliament and eight of the nine provinces supported the Bill, subject to amendments. The main concerns raised by the provinces centred on some policy aspects related to the Bill regarding some of the definitions in the Bill, inadequate procedures, systems and processes, the need for more clarity on concepts raised in the Bill, and conflicts with other legislation and government policies. The MPRDA Bill provides for state participation in any successful minerals and gas or oil development exercises carried out by the private sector that would result in the state receiving a right to free carried interest in all such exploration and production rights. The MPRDA proposes that the South African government be provided with a 20 per cent ‘free carry’ in all new exploration and production rights.

**VII CONCLUSIONS AND OUTLOOK**

The year 2018 brought positive developments in the energy sector, as a result of the updated IRP that will allow South Africa to focus on building a diverse energy sector that will also encourage the economy. The future looks very positive for renewable energy, and the much-anticipated revised draft of the IRP will help interested parties to understand which parts of the energy sector the South African governments will be supporting in the coming years.
I OVERVIEW

In Spain the energy sector is highly regulated. Its strategic and technical importance requires a strong regulatory framework that ensures a constant supply of energy at the lowest possible cost and meets all local and European environmental requirements.

This regulatory framework has undergone significant changes in the past decade, mainly imposed by European legislation, with the introduction of the directives for the internal electricity market in 1996 and 2009\(^2\) and for the gas market in 1998 and 2009.\(^3\)

During 2013, however, the Spanish government accomplished a structural reform of the energy industry to establish a new regulatory framework to reduce and control one of the main problems of the Spanish energy sector, the ‘tariff deficit’ – the negative correlation between electricity costs and the income obtained from regulated electricity activities.

The reform started with the enactment of Royal Decree-Law 9/2013 of 12 July (RDL 9/2013), whereby certain urgent measures were taken to ensure the financial stability of Spain’s electrical system. The main changes introduced by this regulation aimed to provide the industry with a uniform, transparent and stable regulatory framework, as well as to give economic and financial sustainability to the electricity system and avoid the generation of a tariff deficit. Furthermore, on 27 December 2013, the Electricity Sector Act 24/2013 of 26 December (the Electricity Act 24/2013) was published in the Spanish Official State Gazette. It contained, among other things, the main principles set out in RDL 9/2013 in respect of the remuneration of renewable energy generators. The reform was also completed with a number of royal decrees and further regulations approved during 2014. For instance, the following regulations were enacted at the end of 2013:

\(a\) Royal Decree 1047/2013 of 27 December, which established the methodology for calculating the remuneration for electricity transmission; and

\(b\) Royal Decree 1048/2013 of 27 December, which established the methodology for calculating the remuneration for electricity distribution.

The remuneration scheme established by the Spanish government through the structural reform of the energy industry that started in July 2013 and continued in 2014 deserves particular mention. On 11 June 2014, the regulation on renewable energy electricity generation activity was passed by means of Royal Decree 413/2014 (RD 413/2014), which regulates electricity generation activity using renewable energy sources, cogeneration

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1 Antonio Morales is a partner at Baker McKenzie.
2 2009/72 of 13 July.
3 2009/73 of 13 July.
and waste. On 16 June 2014, Ministerial Order IET/1045/2014 (MO IET/1045/2014) approving the remuneration parameters for standard facilities applicable to certain electricity production facilities based on renewable energy sources, cogeneration and waste was passed. Those regulations established a new remuneration system for facilities producing electricity from renewable energy sources, cogeneration and waste, which replaces the former remuneration regime.

Furthermore, the gas market has also undergone several changes, specifically with regard to the remuneration framework for regulated gas activities (gas distribution, transmission, regasification and storage activities) that was approved by the Spanish government by means of Royal Decree-Law 8/2014 of 4 July (RDL 8/2014), which approved urgent measures to encourage growth, competitiveness and efficiency. The said regulation was incorporated definitively into the Spanish legal system through the enactment of Act 18/2014 of 15 October (Act 18/2014). This Act included commercial deregulation measures and also established an energy efficiency system in line with EU directives.

During 2015, several new regulations were passed by the government. On 16 January 2015, the Spanish government approved the draft bill that modifies the current Act 34/1998 of 7 October on the Hydrocarbons Sector (the Hydrocarbons Act), by means of which an organised market will be created to encourage competition in the gas sector, allowing other suppliers to enter into restricted markets such as the gas market. This regulation was finally approved on 21 May 2015 through the enactment of Law 8/2015, which amends Act 34/1998 of 7 October, on the Hydrocarbons Sector and establishes certain tax and non-tax measures in respect of the exploration, research and exploitation of hydrocarbons.

On 31 July 2015, Royal Decree 738/2015 was passed, which regulates the production of electricity and the procedure for distributing power in non-mainland territories’ electricity systems.

The most important regulation passed by the government during 2015 was Royal Decree 900/2015 of 9 October, which regulates the administrative, technical and economic requirements for the methods of supplying and generating electricity for self-consumption.

On 28 November 2015, the Official State Gazette published two main regulations: Royal Decree 1073/2015 and Royal Decree 1074/2015, both of 27 November. The first of these, Royal Decree 1073/2015, modifies certain provisions in the Royal Decrees on the remuneration of electricity networks (Royal Decree 1073/2015), specifically Royal Decree 1047/2013 of 27 December 2013 for transmission, and Royal Decree 1048/2013 of 27 December 2013 for distribution, referred to above. Among other aspects, Royal Decree 1073/2015 eliminates the yearly update of unitary values based on the consumer price index, in accordance with Law 2/2015 of 30 March on de-indexing the economy. The second regulation, Royal Decree 1074/2015, modifies certain regulations in the electricity industry to ensure they are in line with the Spanish government’s electricity reforms of the past few years (Royal Decree 1074/2015).

During 2016, the reform of electricity distribution remuneration was concluded. Ministerial Order IET 980/2016 of 10 June established the remuneration of the different distribution companies in accordance with the new legal framework created by the Electricity Act 24/2013. Ministerial Order IET 980/2016 was partially repealed by several judgments of the Spanish Supreme Court (among others, those of 30 October 2018, 21 December 2018 and 8 January 2019).

One of the main amendments passed in 2016 was Royal Decree Law 7/2016 of 23 December on financing the cost of the social tariff and protective measures for vulnerable
electricity consumers (Royal Decree Law 7/2016), which amended the Electricity Act 24/2013. The new financing mechanism allocates social tariff costs to company sectors based on the number of customers of their retail subsidiaries, and creates the possibility for highly vulnerable consumers to avoid the interruption of their electricity supply.

The Energy Efficiency Directive 2012/27/EU of the European Parliament and Council (Directive 2012/27/EU) was partially transposed in Spain by Royal Decree 56/2016 of 12 February (Royal Decree 56/2016) in terms of energy audits, accreditation schemes for energy services providers and energy auditors, and promoting energy efficiency in production processes.

During 2017, the most relevant regulations were Ministerial Order ETU/120/2017 of 1 February, which determines how information is communicated by the autonomous communities and local entities regarding their saving and energy efficiency programmes; Ministerial Order ETU/130/2017 of 17 February, which updated the remuneration parameters of the renewable energy installations for the regulatory period between 1 January 2017 and 31 December 2019; and Royal Decree 897/2017 of 6 October, which regulates the figure of the vulnerable consumer, social tariffs and other protective measures for domestic consumers.

In addition, at the end of 2016 and 2017, three competitive procedures were carried out for the allocation of a specific remuneration regime to electricity producers from renewable energy sources.

Furthermore, Royal Decree Law 13/2014 of 3 October, through which urgent measures in relation to the gas system were adopted, was partially repealed by judgment 54/2017 of 21 December of the Constitutional Court, in particular with regard to the Castor underground natural gas storage facility.

During 2018, multiple regulations were passed by the Spanish government, including:

- Royal Decree-Law 15/2018 of 5 October on urgent measures for energy transition and consumer protection;
- Royal Decree 1048/2018 of 24 August, amending Royal Decree 1054/2014 of 12 December, which regulates the procedure for assigning the rights to collect the 2013 electricity system deficit and develops the methodology for calculating the interest rate that will accrue to the rights to collect this deficit and, where appropriate, the subsequent negative temporary imbalances;
- Royal Decree 335/2018 of 25 May, amending various Royal Decrees regulating the natural gas sector;
- Order TEC/1172/2018 of 5 November, which redefines the electrical systems isolated from the non-peninsular territory of the Balearic islands and modifies the methodology for calculating the weekly purchase price and selling price of energy in the production office of the non-peninsular territories;
- Order TEC/1174/2018 of 8 November, establishing the remuneration parameters for standard installations applicable to slurry treatment and reduction installations approved by Order IET/1045/2014 of 16 June, and updated for the period 2017–2019;
- Order ETU/360/2018 of 6 April, establishing the values of the remuneration for the operation corresponding to the first half of 2018 and approving a standard installation and establishing its corresponding remuneration parameters, applicable to certain installations producing electrical energy from renewable energy sources, cogeneration and waste;
g. Order ETU/361/2018 of 6 April, amending the application forms for the social bonus provided for in Annex I of Order ETU/943/2017 of 6 October, implementing Royal Decree 897/2017 of 6 October, regulating the figure of the vulnerable consumer, the social tariff and other measures to protect domestic consumers of electrical energy; and


II REGULATION

i. The regulators

The framework for power distribution between the state and the autonomous regions is directly established in Article 149(1)(22) and (25) of the Spanish Constitution. The former reserves the ‘authorisation of electrical installations when their use affects another region or the transport of energy out of its territorial scope’ to the state’s exclusive jurisdiction. The latter provides that the state has jurisdiction over establishing the basis of the energy regime. According to this framework, facilities within each region are also authorised, and the legal basis of the energy sector have developed.

The state’s broad jurisdiction in this area is reflected in the basic state legislation, which establishes the sector’s regulatory framework: the Electricity Act 24/2013 replaced and repealed the Electricity Act 54/1997 and amended the Hydrocarbons Act. Since these two laws (as enacted and as amended) are very comprehensive and wide-ranging, in practice there is little space for the autonomous regions to regulate.

The Electricity Act 24/2013 consists of 80 articles and is divided into 10 titles, 20 additional provisions, 16 transitional provisions, a repealing provision and six final provisions, and it introduced, among others, the following legislation:

a. The principle of economic and financial sustainability of the electricity system.

b. Article 14 of the Electricity Act 24/2013 regulates the remuneration of the different activities involved in the supply of electricity. The remuneration system is financed by means of the income obtained from regulated activities and is based on objective, transparent and non-discriminatory criteria. Additionally, Section 7 determines that the Spanish government may establish a specific remuneration for the promotion of production from renewable sources, cogeneration and waste.

c. With regard to generation activity, the Electricity Act 24/2013 eliminated the former distinction between an ordinary and a special regime, establishing different economic regimes in accordance with the technology and the capacity of the generation facilities.

d. Specific rules on the Voluntary Price for the Small Consumer (PVPC) mechanism are set out in the Electricity Act 24/2013. As this reform seeks to guarantee the supply of electricity at the lowest possible price, the PVPC is the highest price that the major electricity retailers may charge certain consumers.

In addition to the above, Act 3/2013 of 4 June created a regulatory body, the National Markets and Competition Commission (CNMC), which encompasses different supervisory authorities in different sectors: the former National Energy Commission, the National
Competition Commission, the Telecommunications Market Commission, the Rail Regulation Committee, the Airport Economic Regulation Commission, and the National Postal Industry Commission.

Within energy matters, Act 3/2013 transferred certain functions, originally developed by the former National Energy Commission, to the Ministry of Industry, Energy and Tourism, such as inspecting, initiating and conducting certain penalty proceedings, responding to claims made by consumers and informing them about their rights and dispute resolution methods, among others.

### ii Regulated activities

The main activities involved in the supply of energy are the following: generation, transportation, distribution and supply (or commercialisation). As natural monopolies, transportation and distribution are considered regulated activities; whereas generation and supply operate in a free-market system.

Royal Decree 1955/2000, of 1 December, as amended by the Electricity Act 24/2013, regulates the regime applicable to transportation, distribution, commercialisation and supply activities. The management of transportation, as a regulated activity, is entrusted to Red Eléctrica de España, which is also the system operator.

Additionally, Royal Decree 1955/2000 states that the construction, expansion, modification and operation of production facilities, as well as transportation and distribution, require certain permissions. This Royal Decree has been modified by Royal Decree 1074/2015 in relation to the guarantees that must be provided in the authorisation process for production facilities, by Royal Decree 56/2016, which establishes new authorisation criteria for thermal power stations whose thermal power is greater than 20MW to generate electricity, and also for their substantial renewal, including the obligation of the administrative authorisation applicant to submit a cost–benefit analysis to adapt the planned facility to high-efficiency cogeneration and by Royal Decree 897/2017, by which the regulation of the suspension of supply to consumers natural persons in their usual home with contracted power equal to or less than 10kW, is added. Administrative authorisation is needed for the draft technical installation document to be processed in conjunction with the environmental study. An application must be filed with the Directorate-General for Energy Policy and Mining, which is then forwarded with the required documentation to the Ministry of Industry, which makes the decision. If the application is approved, the Ministry will indicate the time within which the application must be submitted for project-implementation approval, which – once approved – allows the owner to construct or establish the installation. The application must be submitted to the industry and energy sub-office where the facility is located. A decision must be arrived at within three months by the Directorate-General for Energy Policy and Mining, specifying a deadline for the construction of the facility.

Once a project is duly implemented, an operating authorisation allows energy to be transmitted to the facilities for commercial exploitation. The application to operate must be submitted to the industry and energy sub-office and should be accompanied by the final certificate of work.

Some autonomous regions have specific regulations for electrical installations, but they follow basically the same administrative procedure as established by the foregoing state regulations.
iii Ownership and market access restrictions

Electricity network operation (transmission and distribution) is subject to significant economies of scale, which gives them an element of natural monopoly, as it is inefficient to introduce competition into these activities. The Electricity Act 24/2013 (which replaces Law 54/1997, of 27 November to, among other concerns, ensure the financial stability of the Spanish electricity industry) establishes an obligation to separate legal and accounting matters within regulated electric activities (transportation and distribution) that are provided under a financial regime. Deregulated activities (generation and supply) are carried out by operators in a free market and their remuneration is being governed by the laws of supply and demand.

Directive 2009/72/CE and its subsequent incorporation into Spanish law go into greater detail on this aspect and impose an obligation on vertically integrated groups to functionally separate their activities to ensure the autonomy of management and decisions of those responsible for the transportation and distribution networks. In addition, it purports to preserve the confidentiality of commercially sensitive information available to those responsible so as not to compromise competition in deregulated activities.

The former Electricity Act 54/1997 and the current Electricity Act 24/2013 and subsequent legislative developments establish and define the role of the different participants in the electricity sector:

a Power producers are individuals or legal entities that have the function of generating electricity, as well as building, operating and maintaining generating plants. The distinction between ordinary producers and special-regime producers has been eliminated. The Electricity Act 24/2013 established a unified regulation for the ordinary regime and for the production of electricity from renewable sources, cogeneration and waste. Additionally, producers are entitled to temporarily close their production facilities, subject to an administrative authorisation regime, this being one of the main legislative innovations of the Electricity Act 24/2013.

b Electricity transporters are companies that have the function of transporting electricity and construction, maintenance and transportation of transformer facilities. As stated above, in Spain, the management of transport activity is entrusted to Red Eléctrica de España, which is also the system operator.

c Distributors are those companies that have the function of distributing power, and also building, maintaining and operating distribution facilities designed to establish energy consumption points.

d Sellers are legal persons who, by accessing transportation or distribution, have the function of selling electricity to consumers. Among them are ‘last-resort sellers’, appointed by the regulator, which are functionally and legally separate from other companies operating in the sector, and which are responsible for providing energy to consumers benefiting from the ‘tariff of last resort’ set by the government. As noted above, the updated regulation set out new and specific rules on the PVPC.

e Consumers are individuals or corporations who buy energy for their own consumption. Consumers who purchase energy directly in the production market are referred to as ‘direct market consumers’.

f The market operator (OMI-Polo Español SA, or OMIE) is the company that assumes the management of the bids for and sale of electricity in the daily and intraday power market in exchange for a regulated fixed fee within the territory of the Iberian Peninsula (Spain and Portugal). OMIE is regulated by the Santiago International Agreement,
regarding the implementation of an Iberian electricity market (MIBEL) between the Kingdom of Spain and the Republic of Portugal, and subject to the rules and regulations governing Spain’s electricity sector. Half of OMIE’s stock is owned by the Spanish company OMEL, with the other half held by the Portuguese company OMIP SGPS, SA.

The system operator (Red Eléctrica de España) is the company whose main function is to perform activities associated with the technical operation of the electricity system, ensuring the continuity and security of the electricity supply and proper coordination of production and transportation systems.

On 10 October 2015, the Official State Gazette published Royal Decree 900/2015, which regulates the administrative, technical and economic requirements for supplying and generating electricity for self-consumption, establishing a regulatory framework that guarantees the economic sustainability of the system and adequate distribution of system costs.

It also stipulates the tolls and charges payable for self-consumption, in accordance with the Electricity Act 24/2013, which already established that self-consumption must contribute to financing the costs and services of the system to the same extent as other consumers (the criticised ‘tax on the sun’). Specifically, Royal Decree 900/2015 imposes the aforementioned tolls and charges on self-producers, both at a fixed cost according to installed power capacity and at a variable cost according to the electricity self-consumed. The regulation also considers a specific surcharge for those who use batteries to store some of the electricity produced by their solar panels. There are two exceptions to this rule whereby consumers are exempt from paying costs:

- consumers on islands; and
- small consumers with a contracted capacity of no more than 10kW.

Accordingly, a record of self-consumption facilities has been created so that system operators and electricity distributors are aware of generation facilities within their networks, and to therefore ensure the correct operation of the electricity system under safe conditions. Royal Decree 900/2015 establishes two categories of self-consumption depending on the size of the facilities: (1) facilities with a capacity generation lower than 100kW, which may feed their excess capacity into the grid, but without receiving any compensation in return; and (2) large producers – facilities with a capacity generation higher than 100kW, which may charge for the excess energy that they feed into the grid, at the current wholesale market price when the energy is provided. Nevertheless, such activity is, from a legal point of view and for tax purposes, equal to production activity and consequently subject to power generation charges and to the 7 per cent tax on energy production.

Lastly, the Royal Decree gives consumers, installers and other agents a period of six months to adapt to its provisions.

The Spanish Supreme Court issued ruling No. 1542/2017 dated 13 October 2017, by means of which it is stated that self-consumers shall also contribute to the electrical system costs provided that they are connected to the grid. Self-consumers demanded that the obligation imposed by Royal Decree 900/2014 was a kind of ‘levy on the sun’, but our Supreme Court has rejected their petitions.

On 24 December 2016, the Royal Decree Law 7/2016 was published in the Spanish Official State Gazette and amended Electricity Act 24/2013 in relation to the financing
mechanism of the cost of the social tariff. It allocates social tariff costs to company sectors on the basis of the number of customers of their retail subsidiaries. The social tariff will cover the difference between the PVPC and a base value that may vary depending on the categories of vulnerable consumers established.

In addition, it creates another group, of ‘severely vulnerable consumers’, whose supply cannot be interrupted, as well as co-financing their invoices by the relevant administration and by the obligated companies of the sector.

On 7 October 2017, Royal Decree 897/2017, which further developed Royal Decree Law 7/2016, was published in the Spanish Official State Gazette. Royal Decree 897/2017 defines the figure of the vulnerable consumer, associating it, as a general rule, with certain thresholds of income referred to the Public Indicator of Income of Multiple Effects, based on the number of members that make up the family unit. The thresholds can be increased if special circumstances are proven for one of the members of the family unit.

Royal Decree 897/2017 was further modified by Royal Decree 15/2018, regarding urgent measures for energy transition and consumer protection.

Additionally, selected groups are recognised as being eligible for the social bonus regardless of their level of income. Within groupings of vulnerable consumers, a higher social bonus is established for severely vulnerable consumers, which are defined by reference to lower income thresholds than those indicated in general terms. It also creates a differentiated category among severely vulnerable consumers, namely, consumers at risk of social exclusion, who are those that are being served by the social services of an autonomous or local administration. This allows for inter-administrative cooperation, which constitutes an additional mechanism to protect consumers in situations of energy poverty and vulnerability. The three categories defined above will receive the following benefits:

- a vulnerable customers, who receive a 25 per cent discount;
- b severely vulnerable customers, who receive a 40 per cent discount; and
- c severely vulnerable customers at risk of social exclusion (100 per cent discount), and customers accredited by the social services as paying at least 50 per cent of their bills.

IV Transfers of control and assignments

Royal Decree 1955/2000 also establishes the authorisation process for the transfer of installations. The request for authorisation for facilities transfer must be sent to the Directorate-General for Energy Policy and Mining, enclosing supporting documentation about the applicants. A decision must be rendered by this department within three months (failure to respond positively within three months means the application is deemed rejected), prior to the report of the CNMC. The applicant then has six months to confirm the transfer, following which, provided that it is not formalised, the authorisation will expire. As mentioned before, Royal Decree 1074/2015 amended Royal Decree 1955/2000 in relation to the guarantees that must be provided in the authorisation process of production facilities.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Energy (electricity or natural gas) is transported from the point where it is generated to the point of consumption by large industrial consumers that are directly connected to the transmission system and to the point of intersection with the distribution networks (substations), through which power is carried to the remaining consumers.
The electricity transmission network is made up of lines of voltage equal to or greater than 220kV, international connection lines regardless of voltage, transformers of 400/220kV, transformer compounds of voltage equal to or greater than 220kV, and other elements of voltage equal to or greater than 220kV. There are also international interconnection facilities connecting Spain with other Spanish territories, which have a voltage transport function lower than 220kV.

Transport networks are developed when new investment is periodically approved by the Ministry of Industry. The construction of network sections included in this planning is regulated, and remuneration is calculated by the regulator in accordance with the approved methodology contained in the regulations, defined in Royal Decree 1047/2013. Law 17/2007 established the single-carrier model, with Red Eléctrica de España as the owner of the entire transportation network. As the system operator, it must comply with the relevant instructions by filing investment plans for future years.

ii Transmission/transportation and distribution access

Power distribution brings the energy from the output of transport networks (electricity or gas) to the final consumer. Electrical distribution facilities comprise voltage lines lower than 220kV, which are not considered part of the transport network.

Prior to June 2009, distribution companies were also responsible for servicing a regulated tariff supply to consumers. Since then, regulated supply has disappeared, creating a ‘last-resort supply’ (TUR), which will be managed by ‘suppliers of last resort’, who must supply electricity at a price no higher than that fixed by the government. At present, specific rules on the current PVPC were set out in the Electricity Act 24/2013. This Act restricted the tariffs to two groups of consumers: (1) consumers considered vulnerable; and (2) consumers who temporarily do not have a supply contract with a free-market retailer and are not entitled to the application of the PVPC. Therefore, the Spanish government will establish by regulations the provisions required to determine the PVPC and last-resort supply, with these being configured as regulated tariffs. Also, the electricity supply will be carried out in accordance with Royal Decree 216/2014 of 28 March, which set out the method for calculating voluntary prices for the small consumer of electrical energy and the legal framework for contracting. Accordingly, the prices introduced by Royal Decree 216/2014, which entered into effect retroactively as of 1 April 2014, apply only to those consumers whose contracted power capacity does not exceed 10 kilowatts. Finally, Ministerial Order ETU/1948/2016 of 22 December, which further develops Royal Decree 216/2014, fixed certain values of the commercialisation costs for referral suppliers to be included in the PVPC for the period 2014–2018.

Distributors must build, maintain and operate power grids linking transport to consumption centres. For the proper development of these functions, distributors have the obligation to expand distribution facilities when needed to meet new demands for electricity, at all times ensuring an adequate service quality level, and differentiating by type of consumption and area. Furthermore, distributors are responsible for supply measurement, applying consumer tolls or access fees.

Distributors are required to keep a points-of-supply database, always maintaining confidentiality. They must send the required customer information to the Supplier Switching Office and provide reports to the transporter about their network incidence and maintenance plans to ensure certainty of supply.
Finally, distribution companies must also provide information to clients, the Ministry of Industry, Tourism and Trade, autonomous communities, the Supplier Switching Office, and the system operator. They must also submit their investment plans annually. Distribution companies, in the exercise of their activities, are entitled to payment by the administration.

Notwithstanding the foregoing, prior to the approval of Royal Decree 222/2008, laying down the emoluments of electricity distribution activity, electricity distributors with fewer than 100,000 customers were covered by a special regulation (established in Transitional Provision 11 of the former Electricity Act 54/1997) with a different financial and regulatory regime from other distributors. Approval of Royal Decree 222/2008 meant that all distribution companies were subject to the same remuneration and policy, therefore removing the previous size differentiation. Royal Decree 222/2008 was subsequently repealed by Royal Decree 1048/2013, which established the methodology for calculating the remuneration of distribution activities.

iii Terminalling, processing and treatment

The Hydrocarbons Act laid the foundations for a reorganisation of the gas system, far removed from the monopoly in which Gas Natural SDG group performed all the activities within the natural gas industry. This Act introduced (1) separation of regulated activities and competition activities, (2) free access for third parties to gas infrastructure, (3) establishment of regulated access charges, (4) progressive full-trade wholesale and retail liberalisation, and (5) regulation of minimum security and strategy.

The Hydrocarbons Act was amended in 2007 by Law 12/2007 of 2 July, which transposed the major changes to the rules of European Union Directive 2003/55/EC (subsequently repealed by Directive 2009/73/CE), to promote the creation of a competitive internal energy market:

a rearrangement of the powers of the different regulatory authorities;
b development of the rules governing access to networks;
c the functional separation of regulated activities;
d regulating the activity supply of last resort;
e creation of the Supplier Switching Office; and
f establishing a schedule of tariff system adaptation and natural gas supply for the supply of last resort.

Directive 2009/73/CE concerning common rules for the internal natural gas market aimed at making a definite contribution to the creation of an internal energy market through the following principles:

a effective separation of network activities from supply and production activities;
b increase of the powers and independence of the national regulators, who must cooperate across a network of energy regulators, but who have the capacity to make binding decisions and impose sanctions;
c the creation of supranational transmission system operators by achieving EU-wide market integration; and

d improvement of the functioning of the gas market and, specifically, greater transparency and access to free storage facilities and LNG terminals.

Furthermore, the Spanish Hydrocarbons Act was amended by Act 11/2013, of 26 July concerning measures to support entrepreneurship and stimulate growth and job creation.
This regulation introduced several amendments by virtue of which distribution agreements are more strictly regulated. Therefore, sale agreements within the sector ‘cannot contain exclusivity clauses which . . . set, recommend or affect, directly or indirectly, the retail price of fuel’ and clauses that ‘determine the sale price of fuel with reference to a particular fixed, maximum or recommended price, or any others that contribute to indirect fixing of the sale price’ shall be void and deemed deleted. Additionally, the Electricity Act 24/2013 repealed Article 83 bis of the Spanish Hydrocarbons Act.

As stated above, Royal Decree-Law 8/2014 and Act 18/2014 introduced several measures aimed at ensuring sustainability and accessibility to the hydrocarbons sector through the establishment of a new remuneration framework for gas distribution, transmission, regasification and storage activities. The purpose of the reform was to ensure the principle of financial and economic sustainability, so that the revenues generated by the gas market are used to finance system costs. Consequently, the revenues must be sufficient to cover all system costs; otherwise, measures should be adopted to increase or reduce the equivalent revenues to maintain the costs-revenues balance. Additionally, regulatory periods of six years were established, but subject to revision every three years (sub-regulatory periods of three plus three years).

For gas distribution, remuneration for the aggregate of the distributor’s facilities is linked to the number of customers connected and to the volume of gas supplied.

For gas transmission, regasification and storage activities, this remuneration system established a common methodology for all facilities of the core network, based on the annual net value of the assets, removing any value update or adjustments made during the regulatory period. The remuneration is composed of the following elements:

- a fixed component for the facility’s availability, which includes annual operating and maintenance costs, depreciation and a financial return; and
- a variable component of continuity of supply, which enables the adjustment of imbalances resulting from fluctuations in demand.

Law 8/2015, which was published on 22 May, amends the previous Hydrocarbons Act to bring it more into line with the current situation, to increase competition and transparency in the hydrocarbons sector, reduce fraud, ensure greater consumer protection, reduce costs for the consumer and adapt the rules on infringements and penalties.

With respect to natural gas, the Law seeks to create an organised natural market that offers consumers more competitive and transparent prices, and allows the entry of new suppliers to increase competition. In this regard, the measures introduced by Law 8/2015 can be summarised as follows: a market operator for the organised gas market will also be appointed; any authorised natural gas installer may carry out inspections (this was previously the responsibility of distributors); the entry of new suppliers is encouraged through the mutual recognition of licences to supply natural gas to other EU member countries where there is an existing agreement; and certain measures have been adopted regarding minimum security inventories, giving suppliers greater flexibility at lower cost, without impairing the security of supply, and enabling the Corporation for Strategic Oil Reserves to maintain strategic natural gas inventories.

With regard to the development of fracking, the Law introduces a tax on the value of the extraction of gas, oil and condensates, which establishes a levy of between 1 per cent and 4 per cent on the production of unconventional gas. It also sets a fee of €125,000 to be paid for each inland exploration survey and production well. The Law provides with particular
force that the revenue collected from both the tax and the fee shall revert to the autonomous
regions and municipalities where the wells are located. Moreover, the companies that hold
exploitation concessions must pay 1 per cent of the value of the production to the owners
of the land around the wells, even where these areas are intended for an activity other than
hydrocarbon extraction.

On 31 October 2015, Royal Decree 984/2015 of 30 October was published, which
regulates the organised gas market and third-party access to natural gas system installations.
This Royal Decree contains the basic regulations for the operation of this new organised gas
market, along with other measures, such as the inspection procedures for gas installations.
In compliance with Article 32 of Royal Decree 984/2015, the Organised Gas Market
Agents Committee was established on 28 January 2016. This Article regulates the organised
gas market and third-party access to natural gas system facilities. The Agents Committee
is formed by representatives of the agents, Spain’s National Commission for Markets and
Competition (CNMC), the transmission system operator, the market operator and the party
responsible for the settlement services.

To sum up, Law 8/2015 provides for the creation of an organised gas market on the
Iberian peninsula, and nominates MIBGAS SA as its operator. This mandate is statutorily
developed in Royal Decree 984/2015, which regulates the organised gas market and
third-party access to natural gas system facilities; in the Resolution of 4 December 2015,
issued by the Secretary of State for Energy, which approves the market’s rules, the adhesion
contract and the decisions of the organised gas market; and in Circular 2/2015 of 22 July,
issued by the CNMC, which lays down the balancing rules for the gas-system transmission
network. The MIBGAS trading platform is used for the purchase and sale of natural gas with
physical delivery at the virtual balancing point for within-day, day-ahead, balance-of-month
and month-ahead products.

Additionally, the ruling issued by the Spanish Constitutional Court of 21 December
declares the unconstitutionality of Articles 2.2, 4, 5 and 6, the first additional provision
and the first transitory provision of Royal Decree-Law 13/2014 of 3 October, which adopts
urgent measures in relation to the gas system and the ownership of nuclear power plants.
Thus, the Spanish Constitutional Court has annulled the compensation procedure for the
promoters of the Castor underground gas storage facility, owing to the lack of ‘urgent need’
that would justify approving a Royal Decree-Law in this regard.

### Rates

Remuneration for transportation and distribution are administratively established in response
to investment costs, operation and maintenance, and network management, according to a
calculation model defined by the regulator by royal decree and in accordance with provisions
established in the former Electricity Law 54/1997 and the current Electricity Act 24/2013
(Article 14.8). Thus, the remuneration is established by reference to the costs required to
build, operate and maintain the facilities complying with the principle of covering the
electricity supply at the lowest cost. Accordingly, Royal Decrees 1047/2013 and 1048/2013
establishing the methodologies for calculating the remuneration for transportation and
distribution activities have been implemented.

This remuneration methodology is based on the following remunerative principles:

1. **Accrual and Collection**
   - The accrual and collection of the remuneration generated by transmission and
distribution facilities placed into service in year ‘n’ will start from 1 January of year
     ‘n+2’;
b the remuneration for investment will consist of assets in operation that have not been depreciated. The basis for their financial return will be the net value of the assets;
c the financial rate of return on the assets eligible for remuneration out of the electricity system for transportation and distribution companies will be linked to the yield on 10-year government debt securities on the secondary market plus a suitable spread; and
d the remuneration is determined for each regulatory period, which will last for six years, but the remuneration parameters can be reviewed before the start of each regulatory period.

The remuneration methodology of transportation activity should comprise economic incentives for the improvement of the availability of the facilities and any other goal. In the case of distribution, the remuneration methodology must include the formula for remunerating other regulated functions performed by distribution companies, as well as any incentives that may be appropriate for the improvement of the supply’s quality, reduction of losses, combating fraud, innovating technology and any other goals.

v Security and technology restrictions

Security in relation to transportation facilities of electrical energy is relevant from the perspectives of both industrial safety and security of supply.

Industrial safety is dealt with by Law 21/1992 of 16 July and the Electricity Act 24/2013, and is understood as safety aimed at risk prevention and control, as well as protection against accidents and disasters capable of causing harm to the population or damage to flora, fauna, property or the environment. Security of supply is dealt with under the sector-specific regulations. The Electricity Act 24/2013 states in this regard that the ‘few basic technical rules needed will be established to ensure the reliability of electricity supply and installations of transport network’.

IV ENERGY MARKETS

i Development of energy markets

According to the Electricity Act 24/2013, electricity production takes place in the electrical power production market in a free-competition regime. The electricity production market is composed of all energy purchase and sale business transactions and other services related to the supply of electricity. It includes forward markets, a daily market, an intraday market, the resolution of system technical constraints, ancillary services and the management of deviations.

The Spanish electricity market has historically offered competitive prices for end users compared with other European markets. The Iberian Electricity Market was started in 2007, and the results of integration in the market have been obvious: while in the second half of 2007 the average price differential between the Portuguese and Spanish electricity systems was €10 per MWh, this fell to €0.3 per MWh by 2010, with identical rates on both sides of the border for the majority of the time.

The operation of the wholesale market at any given time is determined by the mix of generation structure, import capacity, the imperfect meshing of the network, the inelasticity of demand and the system reserve margin. The market-design rules can make this operation more or less efficient, but cannot make up for significant deviations in these factors.
From the opening to competition of the generation market in January 1998 to 2005, almost all of the transactions in wholesale energy were carried out in the pool. Forward markets and bilateral contracts have been developed gradually with the evolution of the regulations. Thus, in recent years, the energy involved in the daily market run by OMIE has ranged between 45 and 55 per cent of demand, with the remainder opting for bilateral transactions.

Despite the reduction in the quantities traded in the daily market, its price still represents the main visible energy price reference and the underlying settlement of bilateral contracts, the over-the-counter (OTC) market and forward markets organised by OMIP.

In this context the significant increase in OTC negotiations on the financial market should also be noted. The volume of energy traded in this market went from 6 per cent of domestic demand in 2007 to 10 per cent in 2010.

The low prices in the Spanish wholesale market compared with their European counterparts have reflected the influence of generation technology’s price takers. As an illustrative example, in the period from December 2009 to March 2010 the market price showed a very substantial fall even below fuel price, reaching an average of €19.6 per MWh in March 2010, reflecting, inter alia, prices of zero euros per MWh for almost 300 hours. One of the main causes of this was a 1.91 per cent reduction in demand, along with growth in wind production coinciding with intense rainfall.

ii Energy market rules and regulation

Since 1998, the Spanish electricity sector has undergone a major transformation as a result of regulation changes resulting from the adoption of Directive 96/92/EC, the main objective of which was to create an internal market for electricity in the EU by liberalising electricity generation and sale.

The electricity markets are regulated by:

a a market operator, responsible for the preparation of the daily operation of the system, matching offers and demands, supervised by a committee of representatives of producers, distributors, traders and qualified consumers;

b a system operator, ensuring continuity and security of supply (Red Eléctrica de España);

c the Electricity System Commission, which protects consumer interests and ensures the transparency of the whole system;

d the Industry and Energy Ministry must supervise the correct operation of production activities and consumption of electricity;

e autonomous communities, which also have direct responsibilities in regulating their electrical systems; and

f the European Union, which establishes the general framework of the electrical system in all countries of the Union through directives and legal regulations.

Royal Decree 949/2001 (amended by Royal Decree 984/2015 on organised gas market and third-party access and by Royal Decree 335/2018 which modifies several Royal Decrees regarding natural gas sector), which regulates third-party access to gas infrastructure and establishes an integrated economic system of the natural gas for regulated activities paid under rates, tolls and regulated fees, as amended, also sets out the basic criteria for remuneration of regulated activities, setting tariffs and fees to be paid by individuals for the use of gas installations.

iii  Contracts for sale of energy
Participants in the energy market may freely agree the terms of contracts for the sale of electricity to subscribe, subject to the terms and minimum content, under the Electricity Act 24/2013 and its implementing regulations. MIBEL consists of the forward markets managed by OMIP and the daily market and intraday markets managed by OMIE.

Electricity traded through daily and intraday markets is remunerated on the basis of the prices resulting from the balance between supply and demand of electricity offered. In other words, it is a marginal pricing market in which the price and trading volume in each hour are set according to the point of equilibrium between supply and demand. Electricity traded through bilateral contracts or the physical or term market is remunerated on the basis of the price of the firm’s contracted operations in those markets.

iv  Market developments
Historically, the energy market has functioned properly, but in recent years a technology-driven influx of price takers has distorted its proper functioning. This has caused a reduction in the wholesale market price, which, together with a reduction in the thermal gap, is not sending the right economic signals to garner investment in new capacity.

This situation will only deteriorate in the future, as the progressive decarbonisation production mix forecasts a greater presence of non-renewables, relegating thermal technologies to the role of providing back-up power, with only a residual role as contributor energy, and jeopardising the recovery of investment. Incentives for investment and the availability of service, established in Order ITC/3127/2011 of 17 November (recently modified by the Ministerial Order ETU/1133/2017 of 21 November and Ministerial Order ETU/971/2017 of 17 October and Ministerial Order TEC/1366/2018), have not sent sufficient economic signals to encourage investment in new back-up power in the region of 500 hours per year, which highlights the need to revise that target.

In particular, a procedure to assist supply security was introduced in 2011 with the aim of ensuring a level of domestic coal consumption according to the provisions of the National Coal Plan (which justifies the operation of these plants for security of supply and capacity for each state to give priority to indigenous sources for up to 15 per cent of production). This regulatory change involves the generation of coal that is bought (10 plants totalling 4,700MW) at a regulated price, while production in the process of withdrawal of the production–demand balance (imported coal and combined cycle) does not receive any compensation. Nevertheless, according to the Framework Agreement for Coal Industry and Mining Districts for the period 2013–2018, the incentivising mechanisms expired at the end of 2014. The Spanish government proposed renewing the incentives granted to power plants that burned national coal. For that purpose, on 31 March 2015, the Spanish government presented a draft Proposal of Order regulating an incentive for investment in environmental performance improvement for electricity generating facilities from indigenous
coal to the Commission on the Monitoring of the Coal Plan for the period 2013–2018. The draft Proposal of Order was subject to prior review by the CNMC and notification to the European Commission. The CNMC issued its report on 30 September 2015, stating that the measures established in the draft Proposal of Order were not justified with regard to the necessity and proportionality of the objective, and expressly pointed out that such measures could fall within the scope of the definition of state aid under European law and thus be duly notified to the European Union pursuant to Articles 107(1) and 108(3) of the Treaty on the Functioning of the European Union. The European Commission responded negatively to the draft Proposal of Order in February 2016.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The Electricity Act 24/2013 eliminated the former distinction between ordinary and special-regime installations and replaced them with a remuneration system based on the technology and capacity of the generation facilities. Under the former remuneration system, special-regime installations, which include renewable energy sources, were not subsidised in the state budget. Instead, they were included in electricity rates, causing a ‘tariff deficit’; however, it was not only renewable energy premiums that generated a tariff deficit, so did other items, such as regulated tariff billing. In fact, the special-regime premiums caused only one-third of the tariff deficit.

Royal Decree 6/2009, dated 30 April, had previously attempted to limit the increase of the aforementioned general tariff deficit; however, it was not sufficient, given that only a year later further steps needed to be taken by the government and Royal Decree-Law 14/2010 was passed for this purpose. In this context, the purpose of Royal Decree-Law 1/2012 was to limit the impact of renewable premiums in the tariff deficit, thus reducing costs; in similar terms, Royal Decree-Law 2/2013 aimed to mitigate the tariff deficit by modifying the remuneration system of regulated activities as well as the remuneration formula for special-regime facilities.

In addition, there were several regulatory changes during 2012 and especially during 2013 in relation to energy production from renewable sources, cogeneration and waste.

As stated above, the Spanish government has accomplished a structural reform of the Spanish energy sector, starting with the enactment of RDL 9/2013. This regulation focused on addressing ‘the pressing need to immediately adopt a series of urgent measures that will ensure the financial stability of the national electrical grid and, likewise, the advisability of overhauling the regulatory framework so that it can adapt to the events and situation that define the electricity sector at any given period, with the objective of maintaining the sustainability of the electrical system’.

The RDL 9/2013 regulation abolished the former remuneration system based on a regulated tariff (the only one in existence since RDL 2/2013 was enacted), even for generation facilities in operation at the time this regulation entered into force. It replaced the previous regime with a system in which power plants producing electricity from renewable energy sources, cogeneration and residual waste receive ‘a specific remuneration that is composed of an amount per installed power unit/facility (which covers, where applicable, the investment costs for a standard plant that cannot be recovered from the sale of electrical power), in addition to an amount for the operation itself (which covers, where applicable, the difference between operating costs and the revenue obtained from the market by said standard power plant)’.
This specific remuneration is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’. Thus, production facilities receive a ‘reasonable profitability’ based on standardised costs and revenues for a standard power plant.

The provisions contained in RDL 9/2013 relating to the remuneration system for producers of energy from renewable sources, cogeneration and waste were basically carried into the Electricity Act 24/2013.

Accordingly, Section 5 of Article 14 of the said Act (recently modified by Royal Decree 1/2019) determines that the remuneration for generation activities includes the following concepts:

a. correspondent remuneration for participation in the daily and intraday market for generation;

b. the system adjustment services required to guarantee a suitable supply to the consumer;

c. when applicable, remuneration through the capacity remuneration mechanism;

d. when applicable, additional remuneration for generation activities carried out in the electricity systems of non-peninsular territories; and

e. when applicable, specific remuneration for the generation of electricity using renewable energy sources, cogeneration and waste.

RD 413/2014 specifically regulates the remuneration system for facilities generating electricity from renewable energy sources, cogeneration and waste. Thus, power plants producing electricity by these methods may also receive a specific remuneration, in addition to the electricity market price, composed of the following elements:

a. ‘remuneration according to the investment’, which is an amount relative to the installed power unit or facility, and covers, where applicable, the investment costs for a standard plant that cannot be recovered from the sale of electrical power; and

b. ‘remuneration according to the operation’, which is an amount relative to the operation itself, and covers, where applicable, the difference between operating costs and the revenue obtained from the market by said standard power plant.

This specific remuneration, that allows power plants producing electricity from renewable energy sources, cogeneration and waste to achieve a reasonable rate of return, is calculated on the basis of a ‘standard power plant, over the useful regulatory life thereof and based on the business activity that would be carried out by an efficient and well-managed company’.

The RD 413/2014 defines the concept ‘reasonable rate of return’ by referencing the pre-tax return on the secondary market average yield on 10-year government bonds for the 24 months prior to May of the previous year as of the beginning of the regulatory period, increased by a differential. Each regulatory period will last for six years, with the first starting on 14 July 2013 and lasting until 31 December 2019.

Notwithstanding the above, those facilities that benefitted from a feed-in tariff regime as of 14 July 2013 will receive a reasonable rate of return based on the pre-tax return on the secondary market average yield on the 10 years prior to the entry into force of RDL 9/2013 government bonds, plus 300 basis points. The specific remuneration will be granted to new power plants producing electricity from renewable energy sources, cogeneration and waste, by means of a competitive tendering process respecting transparency, non-discrimination and objectivity principles. Once power plants producing electricity from renewable energy sources, cogeneration and waste have completed their useful regulatory life, they would
not be entitled to receive any specific remuneration and would merely obtain the income associated with participation in the electricity market. Lastly, the remuneration parameters based on standardised costs and revenues for a standard power plant are set forth in MO IET/1045/2014. MO ETU/130/2017 updates the retributive parameters of the standard installations applicable to certain electricity production facilities from renewable energy sources, cogeneration and waste for the period between 1 January 2017 and 31 December 2019. Specifically, the following were revised:

a. The plotting of real prices against estimations for the first half-period that has elapsed (2014–2016). This reveals a deviation collection entitlement for the price included in the regulation of the years 2014–2016, which will be offset over the remaining useful life of the assets.

b. An update to the plotting of prices for the second half-period (2017–2019) and an update to the remuneration parameters for standard installations, applicable from 1 January 2017 onwards.

c. An update to the technological indication coefficients, with figures from the past three years.

As stated above, the Spanish government has carried out three competitive procedures (renewable auctions) for the allocation of the referred specific remuneration regime to electricity producers from renewable energy sources, cogeneration and waste:

a. First renewable auction: Royal Decree 947/2015 of 16 February set the first call for the provision of the specific remuneration regime to new biomass and wind installations and Ministerial Order IET/2212/2015 of 23 October regulated the procedure for the provision of such specific remuneration regime. Finally, by virtue of resolution dated 18 January 2016, the General Directorate of Energy Policy and Mining awarded 500MW of wind power capacity and 200MW of biomass capacity.

b. Second renewable auction: Royal Decree 359/2017 of 31 March established a call for up to 3,000MW of installed power for the granting of the specific remuneration regime to new installations for the production of electricity from renewable energies in the peninsular electrical system. Ministerial Order ETU/315/2017 of 6 April approved the procedure for assigning the specific remuneration regime in the call for new installations for the production of electric energy from renewable energy sources. The General Directorate of Energy Policy and Mining awarded through a resolution dated 19 May 2017 the 3,000MW to mainly renewable energy producers from wind and photovoltaic power.

c. Third renewable auction: the third call for the additional provision of 3,000MW of installed capacity has been regulated through Royal Decree 650/2017 of 16 June, and Ministerial Order ETU/615/2017 of 27 June, which aimed to introduce the necessary modifications to Ministerial Order ETU/315/2017 to allow its full application to the new auction. By resolution dated 27 July 2017 the General Directorate of Energy Policy and Mining awarded the relevant capacity.

After the three auctions were held, all of the MW of power with available installed capacity were awarded. These results show that the new facilities for the generation of electrical energy from renewable energy sources are configured as a pillar for the achievement of the objectives.
established in Directive 2009/28/EC of the European Parliament, which promotes the use of renewable energy from renewable sources by 2020, from an environmental point of view and from an economic point of view.

On 1 August 2015, the Official State Gazette published Royal Decree 738/2015, which mainly regulates electricity production activity and the dispatch procedure in non-mainland electricity systems. This Royal Decree establishes a scheme similar to the previous system, with remuneration for fixed costs (which include fixed investment and fixed operation and maintenance costs) and for variable costs (including fuel and variable operation and maintenance costs), and takes into account, within the costs of these systems, the taxes arising from Law 15/2012, on fiscal measures for energy sustainability. Certain aspects of the methodology have been changed to improve the efficiency of the system. The Royal Decree also implements matters already contained in Law 17/2013 of 29 October 2013 to guarantee supply and increase competition in these systems.

The Royal Decree entered into effect on 1 September 2015 and includes, for certain measures, a transitional period that started on 1 January 2012. In accordance with additional Provision 11, the full and final effectiveness of the Royal Decree is subject to the European Commission not raising any objections with regard to its compatibility with Community law.

On 13 February 2016, Royal Decree 56/2016 was published in the Spanish Official State Gazette partially transposing Energy Efficiency Directive 2012/27/EU. Royal Decree 56/2016 sets forth the obligation for large-scale enterprises and groups of companies to carry out energy audits as a measure for organisations to know their situation regarding energy use, and to contribute to the saving and efficiency of energy that is consumed.

It imposes the obligation to carry out energy audits for large-scale companies that:

- employ more than 250 workers; or
- have a turnover of more than €50 million and a balance sheet exceeding €43 million.

The obligation also applies to groups of companies as defined in the provisions of the Spanish Commercial Code that fulfil the applicable above-mentioned requirements. Small and medium-sized companies are exempt from this obligation.

The energy audits must be performed by qualified energy auditors, and the obligation is subject to inspection by the competent authorities in matters of energy efficiency. The audits must cover at least 85 per cent of the total energy consumption of the obliged company’s facilities located in Spain that are involved in the industrial, commercial and service activities. Such audits must be performed at least every four years from the date of the previous energy audit.

The sanctions for non-compliance include fines of up to €60,000 according to Law 18/2014 approving urgent measures for growth, competitiveness and efficiency.

An Administrative Energy Audit Register will be created in the Ministry of Energy, Tourism and the Digital Agenda, to record the information notified by the companies under the scope of Royal Decree 56/2016. It will be public and free of charge.

It is also interesting to mention Order ETU/360/2018, of 6 April, establishing the values of the remuneration for the operation corresponding to the first natural semester of 2018 and approving a standard installation and establishing its corresponding remuneration parameters, applicable to certain installations for the production of electrical energy from renewable energy sources, cogeneration and waste.
ii Energy efficiency and conservation

Objectives and actions on energy efficiency in Spain are part of the policy objectives and progress set by the regions’ institutions. Also, in addition to the objectives approved in the European Council in spring 2007 of reducing greenhouse gas emissions and increasing renewable energy, a target was included of improving energy efficiency by 20 per cent in 2020 in the EU compared with the baseline scenario (the target block is commonly called 20-20-20 targets). Unlike the target for 20 per cent renewables and 20 per cent reduction of carbon dioxide emissions, the efficiency target is not binding and has been distributed by Member States.

In line with European objectives set forth in Directive 2009/28/EC of the European Parliament and of the Council of 23 April 2009 on the promotion of the use of energy from renewable sources, the only public reference in a Spanish context has been the 20 per cent target of improving energy efficiency in the government’s ‘Strategy for a Sustainable Economy’ in December 2009, which included a target of 20 per cent reduction in energy usage by 2020 compared with the scenario at that time.

At a national level, the main energy efficiency measures are based on the Spanish Energy Efficiency Strategy (E4) for the period 2004–2012, which has developed in several plans: Plan of Action 2005–2007, Plan of Action 2008–2012 and Plan of Action 2011–2020. The 2008–2012 Action Plan includes a significant number of structured activities and strategic sectors. The measures carried out are divided into the following categories:

a legislative actions, generally far-reaching, and representing a complex set of recommendations, regulations, rules of functioning, constraints and generally binding rules;

b incentive measures for carrying out audits and analysis of consumption of the technologies used, and promoting investment in equipment to increase energy efficiency; and

c training in good practices, knowledge of available technology, advances and new techniques of management demand, consumption and, in general, the correct use of energy.

Alongside this plan, some of the key energy-efficiency measures stated in the Spanish Action Plan 2011–2020 include those in the transportation, building, utilities and cogeneration sectors.

iii Technological developments

One of the main goals within the European Union is to fully achieve energy interconnection and, for that purpose, the European Commission passed the Third Energy Package, which came into force in March 2011. The Third Energy Package sought to accelerate investments in energy infrastructure, to enhance cross-border transactions and provide access to diversified sources of energy.

The European Commission considers the connection of ‘energy islands’, that is, Spain and Portugal on the Iberian Peninsula and Estonia, Latvia and Lithuania in the Baltic Sea region, along with the rest of the internal market as a high priority goal.

A recent example of electricity interconnection as technological developments is the new interconnection grid established between and Spain and France. Both countries have recently finished a €700 million project of common interest that doubles the electrical
connection capacity between France and Spain. It was co-financed by both countries through the incorporation of the company INELFE (50 per cent owned by Red Eléctrica de España and 50 per cent by Réseau de Transport d’Électricité).

VI THE YEAR IN REVIEW

As described above, the Spanish energy sector has undergone a broad reform as a consequence of the government’s attempts to reduce the ‘tariff deficit’ and to re-establish a positive correlation between electricity costs and the income obtained from regulated electricity activities. The main reforms during 2018 are summarised as follows:

a In April 2018, the values of remuneration for the operation corresponding to the first semester of 2018 was established. In addition, the application forms for the social bonus were amended.

b In May 2018, the regulations regarding the natural sector were amended.

c In August 2018, the proceeding for assigning the rights to collect the electricity system deficit was regulated. In addition, the method for calculating the interest rate for the rights to collect such deficit was developed.

d In October 2018, urgent measures were taken for energy transition and consumer protection.

e In November 2018, the electrical systems isolated from the non-peninsular territory of the Balearic Islands were redefined. Also, the remuneration parameters for standard installations were established.

VII CONCLUSIONS AND OUTLOOK

Spain depends heavily on foreign energy and needs all available resources. Its energy system is still in a state of revision, both in the electricity and gas sectors, which creates uncertainty for international investors, who demand safe, predictable and transparent markets. Additionally, the retrospective effect of certain measures adopted since 2013 (i.e., RDL 9/2013) concerning renewable-energy incentives, along with tax relief, have brought uncertainty to potential investors. The main objectives for the Spanish government in the short term are to shore up the markets and counter this uncertainty, but it is also important to outline definitively the energy mix required over the next 20 years; once defined, this plan should remain in place for that length of time.
Chapter 25

SWITZERLAND

Georges Racine

I OVERVIEW

The Swiss energy sector has its own distinctiveness. Switzerland has been referred to as the ‘water tower’ of Europe; indeed, hydropower accounts for about 59.6 per cent of electricity production in the country, while nuclear power accounts for about 31.7 per cent. Other conventional thermal and ‘new’ renewable energies, including solar, wood, biomass, wind, geothermal and ambient heat, account for about 8.7 per cent.2

Despite the country’s high dependence on nuclear energy, the Federal Council has decided to gradually phase out nuclear power. On 21 May 2017, Swiss voters endorsed (by a majority of 58.2 per cent) Energy Strategy 2050, thereby paving the way for a new Federal Energy Act (the Energy Act). The new law and related ordinances came into force on 1 January 2018, setting forth extensive measures to reduce energy consumption, increase energy efficiency and promote renewable energy. The new law bans building new nuclear power plants but allows existing plants to operate for as long as they meet safety standards. This followed an earlier referendum on 27 November 2016, by which Swiss voters rejected (by a majority of 54.2 per cent) the introduction of a cap on the lifetime of existing nuclear power plants in Switzerland, and the Swiss Federal Council’s decision of 4 May 2016 to indefinitely delay the full liberalisation of the Swiss electricity sector.

The Swiss electricity market has been described as being highly fragmented owing to the number of market participants. Such a high number is peculiar, considering the size and population of the country.

Electricity represents approximately 24.8 per cent of Swiss energy consumption, while oil and gas represent about 49.2 per cent and 14 per cent respectively. Coal, wood, industrial waste and other renewable energies constitute the remaining 12 per cent.3

Switzerland produces neither oil nor gas. As such, this chapter focuses on the electricity industry.

1 Georges Racine is a partner at HFW in Geneva, Switzerland. He would like to thank Micah Wells for his assistance in researching materials for this chapter.


II REGULATION

i The regulators

The Swiss energy institutional framework comprises a number of federal offices, regulatory authorities and specialised agencies. The Federal Office of Energy (SFOE) is the office responsible for all questions relating to energy supply and energy use. It sits under the Federal Department of Environment, Transport, Energy and Communications (DETEC), which is responsible for ensuring sustainable development and the provision of basic public services in the interests of society, the environment and the economy.

The SFOE pursues the following objectives:

a to create the necessary conditions for ensuring a sufficient, well diversified and secure energy supply that is both economical and ecologically sustainable;

b to impose high safety standards in the areas of production, transportation and distribution of energy;

c to promote efficient energy use, increase the proportion of renewable energy in the overall energy mix and reduce the level of carbon dioxide emissions;

d to promote and coordinate energy research and support the development of new markets for the sustainable supply and use of energy; and

e to create the necessary conditions for efficient electricity and gas markets and an adapted infrastructure.

A number of commissions support the SFOE, including the Energy Research Commission (CORE), the Commission for Radioactive Waste Disposal (CRW), the Administrative Commission of the Decommissioning Fund and the Disposal Fund for Nuclear Installations (ACDFDFNI), the Nuclear Safety Commission (NSC) and the Commission for Connection Conditions for Renewables Energies (CCRE).

The CORE assists with the formulation of guidelines governing energy research and the implementation of research findings. Its members represent the industrial sector, the energy industry, universities and various energy agencies and research institutions in Switzerland.

The CRW is an independent body that is responsible for advising the SFOE and the Federal Nuclear Safety Inspectorate (ENSI) (see below) on geological aspects of nuclear waste disposal.

The two funds administered by the ACDFDFNI were established to secure the necessary financing for the disposal of radioactive waste and spent-fuel elements, and the decommissioning of nuclear installations after their shutdown.

As an advisory body for the Federal Council, DETEC and ENSI, the NSC examines fundamental issues relating to nuclear safety and may submit comments for the attention of the Federal Council and DETEC regarding reports by ENSI on nuclear safety. It took over the duties of the former Federal Commission for the Safety of Nuclear Facilities on 1 January 2008.

The CCRE advises cantonal authorities and the SFOE on the formulation of recommendations and enforcement tools for the implementation of connection conditions for independent producers.4

The Federal Office for the Environment (SFOEN), which also sits under DETEC, plays an important role alongside the SFOE. It is responsible for ensuring that natural resources are used sustainably, that the public is protected against natural hazards, and that the environment is protected from unacceptable adverse impacts.

In accordance with DETEC’s sustainability strategy, the SFOEN pursues the following goals:

a. long-term preservation and sustainable use of natural resources (land, water, forests, air, climate, biological and landscape diversity) and elimination of existing damage;

b. protection of the public against excessive pollution (noise, harmful organisms and substances, non-ionising radiation, wastes, contaminated land and major incidents); and

c. protection of people and significant assets against hydrological and geological hazards (flooding, earthquakes, avalanches, landslides, erosion and rock falls).

In order to achieve these goals the SFOEN has been assigned the following responsibilities:

a. environmental monitoring to provide a sound basis for the management of resources;

b. preparation of decisions, to secure a comprehensive and coherent policy of sustainable management of natural resources and prevention of natural hazards; and

c. implementing the legal foundations, supporting enforcement partners and providing information on the state of the environment and on the appropriate use and protection of natural resources.5

The Federal Electricity Commission (ElCom) is the independent regulatory authority for the electricity sector. It is responsible for monitoring compliance with the Federal Electricity Act and the Federal Energy Act, taking all necessary related decisions and pronouncing rulings where required.

When the new Electricity Supply Act entered into force on 1 January 2008, ElCom was formally entrusted with the task of supervising the liberalisation of Switzerland’s electricity market. As an independent regulatory authority at the federal level, ElCom is responsible for securing the smooth transition from a monopoly situation in the electricity supply sector to an electricity market based on the principles of competition. ElCom’s duty is to ensure that the liberalisation of the market does not result in excessive tariff increases and that the network infrastructure is properly maintained and expanded in order to guarantee an adequate supply of electricity.

ElCom has been entrusted with extensive judicial powers to effectively perform its various duties. It monitors compliance with the provisions of the Electricity Supply Act and the Energy Act, and can pronounce legally binding decisions and rulings as necessary.

The specific duties of ElCom are to:

a. verify the electricity tariffs of customers who do not have free access to the network, as well as the remuneration paid for the input of electricity into the grid. It is authorised to prohibit unjustified increases in electricity prices, and may order the reduction of excessively high tariffs, taking action on the basis of complaints or in its official capacity;

b. mediate and pronounce rulings on disputes relating to free access to the electricity network;

rule on disputes relating to cost-covering remuneration of electricity input that is to be paid to producers of electricity from renewable energy sources;

monitor supply security and the condition of the electricity networks;
in the case of shortfalls in cross-border transmission lines, to regulate the allocation of network capacities and coordinate its activities with the European electricity market regulators; and

ensure that the transmission network is handed over to the national system operator (Swissgrid) according to schedule.

ENSI is the national regulatory body with responsibility for the nuclear safety and security of Swiss nuclear facilities. It is an independent body constituted under public law.

ENSI is supervised by an independent board elected by the Federal Council and reports directly to it. Its regulatory remit covers the entire life of a facility, from initial planning, through operation, to final decommissioning, including the disposal of radioactive waste. Its remit also includes the safety of staff and the public and their protection from radiation, sabotage and terrorism. ENSI is also involved in transport of radioactive materials to and from nuclear facilities and in the continuing geo-scientific investigations to identify a suitable location for the deep geological disposal of radioactive waste.6

ii Regulated activities

Articles 76 and 89–91 of the Swiss Federal Constitution address energy matters and bind the Confederation and the cantons to provide a satisfactory, diversified, secure, economic and environmentally compatible energy supply.

According to the Constitution, the Confederation is in charge of determining the principles of the use of all domestic and renewable energies in particular, as well as legislating in certain specific areas such as nuclear energy, hydropower generation and transmission and delivery of electricity. Legislation concerning all other areas is to be provided by the cantons. Consequently, energy laws can vary considerably among cantons.

At the federal level, the principal pieces of legislation are:

- energy: the new Energy Act;
- hydropower: the Hydropower Act 1916 and the Water Protection Act 1991;
- electricity: the Electricity Act on Electric Facilities for Low and High Voltage 1902 and the Electricity Supply Act 2007;
- CO2: the CO2 Emission Reduction Act 1999 (the CO2 Act); and

Enacted by the Federal Council on 1 November 2017, the new Energy Act took effect on 1 January 2018. Three new ordinances and a series of revisions to other ordinances also took effect on 1 January 2018. The aims of the new Act are:

- to reduce energy consumption;
- to improve energy efficiency; and
- to promote renewable energy.7

7 Article 1 of the new Energy Act.
The Federal Electricity Supply Act, which was adopted by Parliament in 2007, provides for an opening of the market in two stages, starting on 1 January 2009. In the first five years (2009–2013), only end-consumers with an annual consumption of more than 100,000kWh per site were granted free access to the market. Households and other small-scale end consumers were also supposed to be able to freely choose their electricity supplier as of 1 January 2014, but that full market liberalisation has been delayed, due to the main objective of market liberalisation – the creation of a competitive and secure electricity supply with transparent pricing – not having been achieved. Recent revisions have also been made to this Act in order to make adjustments to the organisation of the electricity market to ensure security of supply, increase economic efficiency and promote energy integration.

In October 2018, the Swiss government reversed its previous stance on liberalisation and presented a draft proposal to completely liberalise the domestic electricity market. Under this proposal, everyone in Switzerland will have the opportunity to choose their electricity supplier freely. The government submitted the proposal to the public for comment and consideration until 31 January 2019. What action the government will take after that date remains to be seen.

Negotiations between the EU and Switzerland to enter into a comprehensive long-term energy treaty began at the end of 2007. The primary aim of such an accord (obtaining this agreement is considered one of the top priorities for Switzerland) would be the mutual access to the free energy market. The negotiations, which were at an advanced stage, came to a halt immediately following the adoption by the Swiss people (9 February 2014) of the Swiss popular initiative ‘Against Mass Immigration’.

### Policy

The Swiss Federal Constitution, the Energy Act, the CO₂ Act, the Nuclear Energy Act and the Electricity Supply Act are all integral parts of the instruments defining a sustainable and modern Swiss energy policy. In addition to legal instruments, the energy policies of the federal government and the cantons are both based on the presentation of energy perspectives as well as on strategies, implementation programmes and the evaluation of energy-related measures at the municipal, cantonal and federal levels.

On the international front, Switzerland has taken action to show its commitment towards a sustainable and modern energy policy. On 20 June 2018, the Federal Council adopted the country report on the implementation of the 2030 Agenda for Sustainable Development. This report, which was presented to the UN in July, showed that Switzerland has already firmly established the UN’s Sustainable Development Goals in its policies, even though some challenges remain.

Energy policy was only anchored in the Swiss Federal Constitution in 1990, when provisions were added stipulating that the federal government and the cantons are obliged to use their competences to ensure an adequate, broad-based, secure, economical and ecological energy supply, and the economical and efficient use of energy. This comprehensive list of requirements places high demands on energy policy at the federal and cantonal levels, while demonstrating how difficult it is to find suitable solutions.

Since 1990, all cantons have drawn up their own energy legislation and regulations, and with the enactment of the Federal Energy Act and the Federal Energy Ordinance on 1 January 1999, the Federal Council fulfilled the mandate it had received following the approval by the electorate of the energy provisions in 1990.
The energy perspectives as drawn up by the Federal Council have served as a basis for all political decisions in the energy field and have been reviewed and updated regularly since the establishment of the General Energy Plan in the mid-1970s.

On 4 May 2016 the Federal Council confirmed that it was indefinitely delaying the full liberalisation of the Swiss electricity market. Due to the economic and political implications of full liberalisation, the Federal Council launched a public consultation process, which took place between 8 October 2014 and 22 January 2015. Following its review of the report on the consultation process and in light of the conflicting views expressed therein, the Federal Council has indicated that full liberalisation will depend on:

a. the evolution of the energy pact with the European Union;
b. the progress achieved with Energy Strategy 2050;
c. the prevailing market conditions; and

d. the revision of the Federal Electricity Supply Act.

Since the adoption of Energy Strategy 2050 and the new Energy Act coming into force, there has been renewed discussion of market liberalisation, notably a report by the SFOE in November 2017 and a motion supported by the Federal Council and SFOE in December 2017. It is expected that liberalisation will go hand-in-hand with the establishment of a strategic reserve.8

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The most significant change in the structuring of the transmission and distribution grid in the Swiss electricity market has been the gradual liberalisation in the past decade of the high-voltage transmission network, and more specifically the separation of the transmission network from other core elements in the electricity market such as distribution, power generation and trading.

The liberalisation of the transmission network was facilitated in large part by the foundation of Swissgrid in 2005 as the Swiss transmission system operator (TSO) and the gradual transfer since then of operational responsibility and legal ownership of the network to Swissgrid.

The transfer of the transmission grid to Swissgrid has consolidated the network (which was previously split up into eight control areas) into one zone covering the entire country. Swissgrid is the owner of the Swiss transmission grid which extends across 6,700 kilometres of lines, 12,000 pylons and 125 substations with 145 switching substations, as well as 41 connections abroad. It is comprised of both 380kV and 220kV lines. While the former are used mainly to import and export electricity, the large Swiss power plants feed the majority of their energy into the 220kV grid. This high-tension voltage is necessary in the transmission grid in order to transport energy over long distances with as little power loss as possible.

Modernising the transmission grid is key to ensuring a sustainable energy future. For Switzerland to have the upgraded grid it needs and wants, it drafted and is implementing Swissgrid’s ‘Strategic Grid 2025’ report, which will invest 2.5 billion Swiss francs for grid upgrade until 2025.

On 1 January 2009, the number of Swissgrid shareholders increased overnight from eight electricity companies, directly or indirectly majority-owned by the Swiss cantons (Alpiq AG, Alpiq Suisse SA, Axpo Power AG, Axpo Trading AG, BKW FMB Energie AG, CKW AG, ewz and Repower AG) to 17 shareholders as part of the opening up of the previously closed system. There are now over 30 electricity generators and distributors that share ownership of Swissgrid.

The Swiss Electricity Supply Act mandated that the transfer of the transmission network from the original owners to Swissgrid be completed by the end of 2012. By the beginning of 2013, most of the network components had been transferred with the remainder completed at the beginning of 2015.

The separation of the transmission network from vertically integrated generation and supply companies occurred in three separate stages (principally between January 2009 and January 2015):

a separation of accounting functions from distribution, production and trading activities;
b legal separation and restructuring of operating entities into subsidiaries; and
c transfer of legal ownership of the network to national operator Swissgrid.9

Swissgrid now owns and operates the Swiss transmission system and has overall responsibility for ensuring security of supply. Its main areas of responsibility are:
a the transportation of electricity from the producing power plant to the end consumer via regional and local distributors; and
b the trading of electricity exported and imported from the rest of Europe.

The transfer to Swissgrid was registered in the commercial register on 3 January 2013. To regulate the behaviour of Swissgrid and other players in a newly liberalised market, the Swiss Transmission Code was introduced in December 2013 as a regulatory mechanism to define the technical and organisational principles governing the Swiss transmission system.10 The regulations govern the relationship between Swissgrid and the distribution system operators, power generators and end consumers, as well as other market players and defines the minimum requirements for the operation, use and connection to the Swiss transmission system.

Due to Switzerland’s central location in Europe, approximately one-third11 of all electricity flow through the Swiss transmission network is transmitted from one neighbouring country to another. Swissgrid coordinates its transnational activities through its membership of the European Network of Transmission System Operators for Electricity.

Swissgrid is also part of the TSO Security Cooperation, an initiative between 13 TSOs to ensure secure energy supplies among its members. The initiative brings together a standing security committee and uses a joint real-time information system (the Real-time Awareness and Alarm System) and shared IT platform to meet its main objective of increasing security on Europe’s high voltage transmission network.12

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10 The transfer to Swissgrid was registered in the commercial register on 3 January 2013. https://www.strom.ch/fileadmin/user_upload/Dokumente_Bilder_neu/010_Downloads/Branchenempfehlung/Branchendokument_TC_2013_VSE.pdf.
11 25TWh of 78TWh in 2014, according to Swissgrid (2015).
12 https://www.tscnet.eu/about-tsc/.
Swissgrid has been a shareholder of the auction platform Capacity Allocation Service Company since 2010, which acts as a service company and single point of contact for the implementation and operation of the power transmission capacity allocation between counties in Europe.

In 2018, Swissgrid began to implement Strategy 2022 to further consolidate its position as the backbone of security of supply in Switzerland. There are four key areas of focus:

a. safety for people;
b. integrated plant and system operations;
c. intelligent use of new technologies; and
d. close cooperation with partners in Switzerland and Europe.13

ii Transmission/transportation and distribution access

The Electricity Supply Act stipulates that electricity grid operators must allow power generators access to the transmission and distribution network. The expenses incurred for making these connections are borne by the individual generators. Power generators of electricity from renewable sources (particularly hydropower) are given priority when it comes to allocating capacity on the grid.

Swissgrid must also by statute allow other regulated third parties access to the grid without discrimination, on a transparent and non-discriminatory basis. Access to the network may be denied, however, for ‘legitimate business reasons’, including when the safe operation of the network could be endangered or when the network is congested.

iii Rates

Swissgrid sets the rates for use of the transmission grid. These are subject to provisions of the Electricity Supply Act and also to review by ElCom. The legislation stipulates that the tariffs (for all distribution and transmission grids) shall not exceed the recoverable costs, fees and royalties. Recoverable costs consist of the operating and capital expenditure associated with Swissgrid’s operation of the grid.

ElCom acts as a price monitor and regulator for the Swiss transmission network operated by Swissgrid. ElCom is vested with the power to order reductions and to prohibit tariff increases.

ElCom takes a proactive approach to its price monitoring duties and has ordered the lowering of grid usage tariffs on several occasions, notably in four consecutive years from 2009 to 2012. These tariff reduction orders were, however, struck down by the Federal Supreme Court in 2013. The method by which ElCom calculates tariffs was subject to another Supreme Court Ruling in 2016 that is expected to have a significant impact on how ElCom is able to regulate tariffs in future.

ElCom also rules as a judicial authority on general disputes relating to network access and tariffs. ElCom monitors electricity supply security and regulates issues relating to international electricity transmission and trading.14

Swissgrid sets the tariffs for use of the grid in accordance with statutory requirements and publishes them at the end of March annually.15

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Swissgrid effected reductions in tariffs for 2018, attributing this reduction to the ‘drop in operating costs brought about by Swissgrid’s ongoing efforts to increase efficiency’. In March 2018, Swissgrid announced that in 2019 the tariff for system services will decrease by 25 per cent (when compared with 2018) and that grid usage tariffs will be up to 21 per cent lower than in 2018. Lower ancillary costs are made possible, according to Swissgrid, as a result of lower operating costs and control reserve power costs. Swissgrid attributes these lower costs to the increase in the number of providers, leading to more competition.

Swissgrid’s grid usage tariff (charged to the distribution system operators directly connected to the transmission grid) is split up in three components:

- working tariff (the energy component);
- power tariff (the power component); and
- fixed basic tariff (per weighted outflow point).

The working tariff is calculated on the basis of the active energy consumed by end consumers directly connected to the transmission grid, and in the case of a grid operator (of which there are more than 800 in Switzerland), the active energy used by end consumers connected to its grid and all lower-level grids. The actual active energy being consumed is multiplied by the working tariff published by Swissgrid.

The power tariff is calculated on the basis of the annual average of the actual monthly ‘quarterly-hour’ peak demand values used by each end consumer directly connected to the transmission grid and by end consumers connected to its grid and all lower-level grids. Deductions are made for the energy required for a power plant’s own consumption and the pump energy used by pumped storage power plants (if declared by the grid operator directly connected to the transmission grid).

If a customer (either end customer or distribution system operator) has feed-out points into the transmission grid, then the tariff calculation is based on the ‘quarter-hourly’ netted values after the appropriate deductions are made. Similar deductions are made to take into account the energy required for power generation and pump energy.

For the fixed basic tariff calculation, each feed-out point for a grid distribution operator is weighted using the ‘K-factor’, where the share of energy being fed out is considered in relation to a formula based on the sum of energy being fed in and out; from an average taken over the previous 12 months.

The grid usage tariff is therefore the result of the following formula:
- multiplying the energy volume by the working tariff;
- multiplying the monthly peak output by one twelfth of the power price; and
- multiplying the number of weighted feed-out points by the fixed basic tariff per weighted feed-out point.
Swissgrid estimates that in 2019 the average Swiss household will pay a total of 45 francs towards the cost of the transmission grid. Swissgrid forecasts that 5 per cent of electricity price paid by end consumers will go towards the operation and maintenance of the national transmission grid in 2019 and that 47 per cent of costs will be attributed to the distribution grids.\textsuperscript{21}

\textbf{iv Security and technology restrictions}

The most significant technology restrictions (and sources of vulnerability) on the Swiss transmission and distribution grids are caused by the fact that most of the network is 40 to 50 years old (and only a third of the network dates from after 1980). Until 2013, planning for the development and expansion of the network was carried out at a local level and therefore considerable work remains to be done to modernise the grid.

Additionally, the limited number of transfer points on national borders with main trading partners Germany, France, Italy and Austria (approximately 40) means that capacity is limited and congestion can occur. The Strategic Grid 2025 is an initiative put in place with the main objective of upgrading the grid in order to ensure that it is technically secure, environmentally friendly and economically efficient.\textsuperscript{22}

Swissgrid acts as the single point of contact for other national 
TSOs and foreign electricity distributors in the negotiation and scheduling of cross-border supply to fill gaps in the Swiss domestic supply. Swissgrid also facilitates capacity auctions for cross-border supply.

Swissgrid is responsible for the safe operation of Switzerland’s high-voltage network from two linked control rooms, operational around the clock and every day of the year.\textsuperscript{23} Swissgrid controls a comprehensive IT infrastructure from which it is able to map a real time model of the Swiss transmission network from approximately 40,000 data points. Thousands of measurements and switch positions from the network are collected and processed in cycles of less than 20 seconds. With these many data points, the system is unquestionably vulnerable to cyberattacks.

The Swiss Federal IT Steering Unit is tasked with implementing a national strategy for the general protection of Switzerland against cyber risks.\textsuperscript{24} Produced annually, the latest report on progress was published in 2016.\textsuperscript{25} The report does not, however, contain any specific policy for dealing with cyber threats to the electricity grid.

Swissgrid has established a new technology business unit in order to design and implement a digitisation and automation strategy.\textsuperscript{26} The Swissgrid research and development unit is tasked with developing new technologies for the efficient transmission of electricity, including the new ‘smart grid’ and ‘super grid’ initiatives. The R&D unit also provides support for third-party innovation projects through sponsorship deals and partnership programmes.\textsuperscript{27}

\textsuperscript{22} http://grid2025.swissgrid.ch/en/.
\textsuperscript{24} www.isb.admin.ch/isb/en/home/themen/cyber_risiken_ncs.html.
This is part of the Strategic Grid 2025 initiative. This has led to the implementation of the first smart grid system by Romande Energie in September 2017, and the banding-together in August 2017 of 11 energy companies to form the Smart Grid Switzerland Association.28

IV ENERGY MARKETS

i Development of energy markets

The decision by the Federal Council to indefinitely delay the full liberalisation of the electricity market followed an earlier announcement on 7 March 2016 by major hydropower producer ALPIQ of its intention to divest up to 49 per cent of its hydropower portfolio with a total installed capacity of 5.2GW. The stake for sale represents roughly 8 per cent of the total Swiss hydropower production or 5 per cent of Switzerland’s total power production.

The sale process initiated by ALPIQ, though now suspended, is a testament to the challenges facing Swiss hydropower producers. Now that the Swiss government is considering full liberalisation, it remains to be seen what impact this will have on said producers and other stakeholders. Under Energy Strategy 2050, the share of hydropower is expected to be well over 50 per cent. Yet for the time being, hydropower producers are struggling. Wholesale prices remain low and the Swiss franc remains strong. Profitability of Swiss power plants has come under strain due to:

a high subsidies for new renewable energies (e.g., wind and solar power);
b low prices for primary energies (e.g., oil, gas and coal);
c the stagnation of the world economy;
d lower carbon dioxide taxes; and
e high duties.

Producers like ALPIQ lack access to end consumers in the non-liberalised segment of the Swiss market, while their traditional clients (including power distributors and large-scale consumers that benefit from partial liberalisation) have been buying abroad.

The Swiss energy market comprises several hundreds of players, including a small number of major consortia with vertically integrated operations, and about 80 power producers, who differ considerably in terms of size and operations. The vast majority of market players are publicly owned regional and local utilities that distribute electricity to their local municipalities. Only some of these regional and local distributors can produce electricity. The largest utilities are responsible for approximately 80 per cent of the power production and 90 per cent of the energy supplied in the country.

ii Contracts for sale of energy

As there is no power exchange in Switzerland, Swiss trading companies trade on the Powernext in Paris, the Energy Exchange in Austria and the Leipzig-based European Energy Exchange. The Dow Jones Swiss Electricity Price Index (SWEP), which was initiated by Aare-Tessin AG für Elektrizität and Elektrizitäts-Gesellschaft Laufenburg AG, and launched in cooperation with Dow Jones in March 1998, provides price indications for over-the-counter electricity

28 https://romande-energie.ch/espace-presse/communiques-de-presse/110908-communique-fr
trading in Switzerland for next-day delivery. The SWEP is the volume-weighted average of the profile adjusted price for hour 12 of all transactions having an impact on hour 11am to 12pm, also taking into account the Index for the past 20 days.29

On 30 October 2013, Elcom gave its green light to an accord between Swissgrid and the European power exchange EPEX Spot. This accord paved the way for the introduction of market coupling at the Swiss border, which is expected to make power trading more efficient. As a power exchange, EPEX Spot is already overseeing short-term electricity wholesale trade in Switzerland.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

Historically, Switzerland’s longest-serving and most important source of renewable energy has been hydropower, but the ‘new’ renewables including solar, wood, biomass, wind, geothermal and ambient heat also play an increasingly important role in today’s Swiss energy mix. Such role will be accelerated with the endorsement by the Swiss people of Energy Strategy 2050. The revised Energy Act that will come into force on 1 January 2018 specifically aims to increase the use of renewable energy, especially from domestic sources, in addition to securing an economic and ecological supply and distribution of energy and using energy economically and efficiently. To that effect, it sets forth specific goals and measures, including the following:

a the domestic production of hydroelectric power will be increased to 37,400GWh by 2035, while domestic electricity production from other renewable sources will be increased to 4,400GWh by 2020 and 11,400GWh by 2035;
b the current feed-in compensation for energy from renewable sources (i.e., solar, wind, biomass and geothermal energy) will be extended until 2022, and large-scale hydroelectric power plants and photovoltaic and biomass power plants may obtain subsidies until 2030;
c subsidies for local renewable sources and energy efficiency measures will be financed by increases in the grid fee;
d promotion of the construction and expansion of power plants, by declaring that renewable sources use is a national interest equal to the protection of nature and heritage; as a result, it will become more difficult to object against new power plants by referring to nature and heritage protection;
e the cantons will have to provide fast approval procedures for the construction and expansion of power plants;
f recourse to the Federal Supreme Court regarding disputes over planning approvals for power plants, will be possible only for legal issues of fundamental importance; and
g the right to use self-produced energy will be expanded.

ii Energy efficiency and conservation

The new Energy Act, which came into force on 1 January 2018, also presents goals and measures targeting energy saving and efficiency, including the following:

a a substantial reduction in energy and electricity consumption is to be achieved by 2035. Compared to the 2000 figures, average energy consumption per person per year

29 http://www.stromkosten.de/maerkte/swiss-electricity-price-index-swep/.

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is to be reduced by 16 per cent by 2020 and 43 per cent by 2035. Average electricity consumption per person per year is to be reduced by 3 per cent by 2020 and 13 per cent by 2035;

b the existing subsidy programme for energy building refurbishments is to be continued after 2019. The subsidies will be increased and partly financed from revenues of the carbon dioxide (CO2) tax. In addition, tax deductions for such refurbishments will be extended;

c as of 2021, the average CO2 emission of new passenger cars must be reduced to 95g of CO2/km (currently 130g of CO2/km). The average CO2 emission of delivery vans and light-duty vehicles must be reduced to 147g of CO2/km; and

d the existing mechanical electricity meters are to be replaced by smart metering systems that provide more specific data and allow efficient electricity supply and consumption.

In 2017, 25 million francs in subsidies was available for electricity saving proposals, through a competitive tender process. In 2018, 50 million francs has been made available, paid for by the surcharge on transmission costs of high-voltage grids.

On 16 August 2017, the Federal Council adopted two proposals to approve the signing of an agreement to link the carbon market in Switzerland to the Emissions Trading Scheme (ETS).30 Once ratified by the EU and Switzerland, the proposed agreement will provide for fungibility of EU (1,800 million tonnes) and Swiss (5 million tonnes) carbon allowances. It is expected that the earliest the proposed agreement could take effect is 2019, which would follow amendment of the CO2 Act.

VI THE YEAR IN REVIEW

The most important development in the Swiss energy sector in the last 12 months has been the government’s proposal to fully liberalise the electricity market. This action, if allowed, will give a major boost to Swiss hydropower companies.

Last year also saw a boost in support of Energy Strategy 2050 achieving one of its goals, as it was agreed that the Muhleberg nuclear power plant will cease to operate in 2019. This should provide huge support to those wishing to fill that energy void left by the closing of the nuclear plant with renewable energy.

In order to support the environment and meet some of the emission goals, the National Council had hoped to pass the CO2 Law, which was to transpose the commitments made in the framework of the Paris Climate Agreement into Swiss law.

After eight years of previous leadership under Doris Leuthard, Minister of the Department of Environment, Transport, Energy and Communications (DETEC), a new minister took office on 1 January 2019.

VII CONCLUSIONS AND OUTLOOK

The year 2019 is expected to be busy in the Swiss energy sector depending on the Swiss government actions after 31 January. The liberalisation has the potential to provide a boost for consumers in lower energy prices, while at the same time giving a boost to the renewable energy sector and companies that specialise in hydroelectric power.

Chapter 26

UNITED ARAB EMIRATES

Masood Afridi and Adite Aloke

I OVERVIEW

The United Arab Emirates (UAE) is a federation of the seven emirates of Abu Dhabi, Dubai, Sharjah, Ajman, Fujairah, Ras Al Khaimah and Umm al-Quwain. The city of Abu Dhabi in the emirate of Abu Dhabi is the federal capital. Abu Dhabi is the largest emirate by area (making up about 86 per cent of the country’s area) and the richest in terms of oil resources. Dubai is the second-largest emirate by size (accounting for about 5 per cent of the country’s total area) and the largest by population. Together, Dubai and Abu Dhabi account for about two-thirds of the country’s population and form the core of its economy.

The UAE’s economy has traditionally been dominated by the petroleum industry but successful efforts at economic diversification have reduced the share of the oil and gas sector in the country’s GDP to approximately 36 per cent. The UAE has an open economy with one of the highest per capita incomes in the world and a sizeable annual trade surplus. The currency is freely convertible and funds can be freely repatriated. The country’s free zones – offering 100 per cent foreign ownership and zero taxes – are a major conduit for foreign investment in the country. The geographical location of the UAE, situated at the tip of the Arabian Peninsula, makes it a central trading post connecting South-East Asian economies with the Middle East, Africa and Europe. With modern communication and thriving ports, the UAE has emerged as an important trading hub between the Indian sub-continent, Europe, Africa and the Middle East.

The powers of the federal and the emirate governments are enumerated in the State Constitution of 1971. Although the country’s government is based on a federal structure, the individual emirates enjoy considerable economic and political autonomy and each emirate largely pursues its own economic policies. Even though Article 120 of the UAE Constitution gives the federal government exclusive legislative and executive jurisdiction over electricity services in the country, in practice the larger emirates of Dubai and Abu Dhabi, to some extent Sharjah, and more recently the northern emirate of Ras Al Khaimah, formulate and implement their own electricity policies. Hence, although there is a Federal Ministry of Energy (which formulates and implements the federal electricity policies), federal legislation on electricity is fairly limited.

Because of the significance of Abu Dhabi and Dubai within the Federation, this chapter focuses primarily on the electricity sector in these two emirates, in addition to the federal laws and policies on electricity.

1 Masood Afridi is a partner and Adite Aloke is a senior associate at Afridi & Angell.
The generation, transmission and distribution of electricity in the UAE is dominated by four water and power authorities. Three of these authorities are owned by the governments of the emirates of Dubai, Abu Dhabi and Sharjah, whereas the authority that operates in the smaller northern emirates is federally controlled. These state-owned authorities serve as the exclusive purchasers and distributors of electricity in the respective emirates. While the private sector has been allowed to participate in the generation of electricity, transmission and distribution is performed exclusively by state-owned authorities.

Abu Dhabi and Dubai currently have the most active private-sector participation in the energy sector. In line with extant regulations, private participants can own up to 40 per cent economic interest in electricity generation plants in Abu Dhabi and up to 49 per cent in Dubai. There has been speculation regarding the introduction of a privatisation policy by the federal government for the northern emirates; however, no formal announcement has been made so far.

Currently, only Dubai, and Abu Dhabi have enacted laws creating specialised regulatory bodies for the electricity sector. These consist of the Dubai Supreme Council of Energy (DSCE), the Dubai Regulation and Supervision Bureau (the RSB Dubai) and the Department of Energy (DOE). The Federal Ministry of Energy and Industry (the Ministry of Energy) regulates the sector at the federal level and works in conjunction with the Federal Electricity and Water Authority (FEWA) to implement the federal government’s electricity policy in the northern emirates.

Increasing population growth and urban development has been responsible for electricity demand in the UAE to grow at double-digit rates, and demand is expected to continue to grow at about 10 per cent annually for the next decade because of increasing population growth and industrial development. There is currently insufficient power generation capacity in the northern emirates of the UAE, and demand in these emirates is being met by construction of additional capacity as well as the supply of power from the larger emirates through the Emirates National Grid (ENG). Some industrial projects have not been able to secure sufficient power supply and have had to resort to captive power generation.

A number of major power projects, both in the field of conventional and renewable energy, are under development to meet the country’s existing and future electricity needs.

II REGULATION

i The regulators

Federal

The Ministry of Energy, the primary regulator at the federal level, was formed pursuant to Federal Decree No. 3 of 2004 by merging the Ministry of Petroleum and Mineral Resources with the Ministry of Electricity and Water. In 2008, the Ministry of Energy was restructured pursuant to Cabinet Resolution No. 11 of 2008 making it responsible for establishing policies for the water and electricity sectors in the UAE and ensuring that other authorities and companies in the state comply with its policies. A separate directorate for the electricity sector was established within the Ministry of Energy, called the ‘Department of Electricity and Desalinated Water’.

In 2014, the federal government further restructured the Ministry of Energy to introduce three new departments:

- the Clean Energy and Climate Change Department;
b the Rationalisation and Energy Usage Efficiency Department; and
c the Regulation and Control Department.

The restructuring was intended to create a more specialised and robust central regulatory authority at the federal level. However, the Ministry of Energy has had little influence in directing policy and implementing projects in the larger emirates of Abu Dhabi and Dubai and remains focused on assisting the smaller emirates in meeting their growing electricity demand.

FEWA, which was established pursuant to Federal Law No. 31 of 1999 (amended by Federal Law No. 9 of 2008) (the FEWA Law), is the dominant player in the northern emirates and engages in all segments of the market, including generation, transmission and distribution. The Ministry of Energy has announced a strategic energy plan to develop the federal government’s electricity services by attracting private investment in the sector.

**Abu Dhabi**

Until recently, Abu Dhabi’s electricity sector was regulated under Law No. 2 of 1998 Concerning the Regulation of Water and Electricity Sector, as amended by Law No. 19 of 2007 and Law No. 12 of 2009, by the Abu Dhabi Water and Electricity Authority (ADWEA) (Abu Dhabi Water and Electricity Law). However, in a recent move to reorganise the water and electricity sector, the Emirate enacted Abu Dhabi Law No. 11 of 2018 (the DOE Law) and Abu Dhabi Law No. 20 of 2018 (EWEC Law). Pursuant to these two laws (1) ADWEA and the Regulation and Supervision Bureau for the Water and Electricity Sector (RSB) have been replaced with a newly established Department of Energy (DOE); and (2) Abu Dhabi Water and Electricity Company (ADWEC) has been replaced by the newly formed UAE Water and Electricity Company (EWEC). All the employees, assets, properties, rights and obligations of ADWEA and RSB have been transferred to the DOE, and those of ADWEC to EWEC. However, this does not impact any of the licences and approvals issued by ADWEC (or any of its subsidiaries) prior to the date of issuance of the EWEC Law. In accordance with the Abu Dhabi Water and Electricity Law read with the DOE Law and the EWEC Law (collectively, the Abu Dhabi Electricity Laws), the DOE shall be responsible for, *inter alia*, controlling, supervising and organising the energy sector in Abu Dhabi and for issuing licences to entities engaged in the ‘energy sector’*. EWEC will be the sole provider of water and electricity in Abu Dhabi and contract with all entities licensed to produce and distribute water and electricity in Abu Dhabi.

**Dubai**

Dubai’s legislation on the electricity sector was historically limited to Dubai Law No. 1 of 1992 (the DEWA Law), as amended by Decree No. 13 of 1999 and Decree No. 9 of 2011, establishing the Dubai Electricity and Water Authority (DEWA). Dubai has since enacted a

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2 ‘Energy Sector’ covers all activities, works and services related to: (1) Production, treatment, storage, transportation, distribution, supply, sale and purchase of gas, oil and derivatives thereof; (2) generation, storage, transportation, distribution, supply, sale and purchase of electricity of all kinds (clean, renewable, traditional); (3) production, treatment, desalination, storage, transportation, distribution, supply, sale and purchase of water; (4) collection, treatment and disposal of sewage and wastewater and the recycling of treated wastewater; and (5) production, storage, distribution and supply of refrigerated liquid for central refrigeration applications.
number of laws to modernise and open the sector to private investment. Two new regulatory bodies have been created: the DSCE, established under Dubai Law No. 19 of 2009 (the DSCE Law), as the apex regulator for the energy sector, and RSB Dubai, established pursuant to Dubai Executive Council’s Resolution No. 2 of 2010, as the specialist regulatory authority for the electricity sector.

As the primary regulator of the energy sector, the DSCE regulates the exploration, production, storage, transmission and distribution of petroleum products (natural gas, liquid petroleum, petroleum gases, crude oil) and electricity. It ensures that the energy and electricity sources satisfy the current and future demands of the emirate of Dubai at affordable prices. The DSCE also proposes any and all initiatives related to the energy sector, which includes the privatisation of its electricity assets and implementing the provisions of Dubai’s Law No. 6 of 2011 Regulating the Participation of the Private Sector in Electricity and Water Production in the Emirate of Dubai (the Dubai Electricity Privatisation Law).

RSB Dubai is authorised to regulate the electricity sector subject to the supervision of the DSCE. RSB Dubai is mainly responsible for regulating, licensing and supervising the electricity generating service providers, facilities and properties. It also determines and establishes standards and controls for electricity generation in the emirate and proposes legislation governing the electricity sector in Dubai.

As with the other emirates, the main player in the electricity market is DEWA, Dubai’s state-owned integrated power generation, transmission and distribution authority.

**Sharjah**

Sharjah created its own electricity authority in 1995, known as the Sharjah Electricity and Water Authority (SEWA). SEWA, established pursuant to Sharjah Emiri Decree No. 1 of 1995, as amended by Emiri Decrees No. 2 of 2000, No. 46 of 2006 and No. 20 of 2008, is authorised to ‘own, manage, operate and maintain’ power stations and electricity transmission lines. As with the other emirates, SEWA is responsible for the generation, transmission and distribution of electricity in Sharjah. SEWA is authorised to determine electricity prices and connection fees, which are subject to approval by the Ruler of Sharjah.

**Northern emirates**

FEWA is responsible for the generation, transmission and distribution of electricity in the northern emirates of Ajman, Ras Al Khaimah, Fujairah and Umm al-Quwain.

**Ras Al Khaimah**

On 10 March 2013, the Ruler of Ras Al Khaimah issued an Emiri Decree No. 4 of 2013 on the Establishment of the Ras Al Khaimah Electricity and Water Authority (RAKEWA) (the RAKEWA Law). This authority is tasked with the regulation, management, operation and maintenance of power stations, water desalination plants, electricity distribution and transport networks in the emirate. The new authority is also responsible for controlling prices of electricity and water in the emirate. Most importantly, the authority is responsible

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3 Member organisations of the DSCE are DEWA, Dubai Aluminium Company Ltd, Emirates National Oil Company, Dubai Supply Authority, Dubai Petroleum Establishment, Dubai Nuclear Energy Committee, Dubai Municipality, Department of Petroleum Affairs and the Road and Transport Authority.
for fulfilling the electricity needs of the emirate, planning for the generation, transport and distribution of electricity in the emirate and managing the government’s investments in the sector.

RAKEWA is to be managed by a board appointed by the Ruler of Ras Al Khaimah, to be headed by a chairman. The board is authorised to issue regulations relating to the electricity sector, which shall be binding on all entities involved in the electricity and water sectors in the emirate.

Despite the establishment of RAKEWA, FEWA continues to own, manage and operate the electricity resources situated in the emirate and is the de facto authority on ground. The RAKEWA Law does not contain any provisions for the transfer of assets from FEWA to RAKEWA and it is presently unclear whether RAKEWA will replace FEWA in Ras Al Khaimah or if the two authorities will operate jointly in the emirate.

ii Regulated activities

All activities connected to the generation, transmission and distribution of electricity in the UAE are regulated and require specific licences from the relevant regulatory authorities.

Under the Abu Dhabi Electricity Laws, regulated activities pertaining to the energy sector include electricity generation, transmission, distribution and supply to premises. Any person or entity intending to carry out these activities is required to be licensed by the DOE.

Under the Dubai Electricity Privatisation Law, regulated activities include ‘any activity related to generating electricity . . . for the purpose of supplying to the Transmission System with produced electricity’ (the transmission system is owned and operated by DEWA). All activities relating to electricity generation, transmission, distribution and supply of electricity are considered regulated activities in Dubai and require a licence from RSB Dubai.

iii Ownership and market access restrictions

As indicated earlier, Abu Dhabi has allowed private sector participation of up to 40 per cent in its power generation sector. In furtherance of its legislative policies in this regard, in 2015 Dubai awarded 49 per cent of the ownership of phase 1 of Hassyan, a 2,400MW clean coal power plant, to a consortium led by Harbin Electric International and ACWA Power (Hassyan Clean Coal Project). At the federal level, while FEWA has since recently been inviting bids from private entities, private sector participation has yet to gather speed in the northern emirates. UTICO (a private sector utility company engaged in electricity generation, transmission and distribution) in Ras Al Khaimah and Emirates Sembcorp Water & Power Co – ESC (a joint venture between ADWEA and a private sector entity, operating a hybrid desalination and power plant by the name of Fujairah F1 Independent Water and Power Plant) in Fujairah are a few examples of private sector partnerships in the northern emirates.

Under Federal Law No. 2 of 2015 on Commercial Companies (the Companies Law), foreigners are permitted to own up to a maximum of 49 per cent of a UAE company (other than in the free zones) and the majority 51 per cent is required to be owned by UAE nationals. The power sector is no exception to this requirement. While Federal Law No. 19 of 2018...
on Foreign Direct Investment (the FDI Law) was recently promulgated\(^5\) to allow 100 per cent foreign ownership of companies in certain sectors in the UAE subject to approval of the UAE Cabinet, the FDI Law sets out a ‘Negative List’ of 13 sectors where existing laws and restrictions will continue to apply and majority foreign ownership will not be permitted. This includes water and electricity services.

Although this restriction is a deterrent to foreign investment, it is not an insurmountable hurdle as informal arrangements exist to enable the foreigner investors to transfer 100 per cent beneficial interest in local companies to themselves. It is common for foreign investors to enter into side agreements with the local majority-owning partners by virtue of which the foreign shareholders assume management powers and at the same time transfer to themselves the economic interest in the shares held by the local. The local shareholder is usually paid a fixed fee as part of this arrangement for acting as a local sponsor. The authorities in the UAE have so far tolerated this practice, and as long as there is no dispute between the parties, the arrangement works to the benefit of all shareholders. The enforceability of these side agreements is questionable and untested in the local courts. Although the local partner could, in theory, take over the business by revoking the side agreements, the arrangement works well in the vast majority of cases and offers a practical way forward for foreign investors wishing to do business in the UAE.

Although the UAE free zones allow for 100 per cent foreign ownership, the free zone companies are not allowed to conduct business outside the free zones and within onshore UAE. To date, there are no power generation, transmission or distribution companies in any of the free zones in the UAE. Electricity rates are subsidised throughout the UAE and it is therefore not viable for private producers to construct power plants within the free zones. Furthermore, the state-owned authorities in the emirates of Dubai and Abu Dhabi have sufficient capacity to meet present and anticipated future needs, and this has therefore not necessitated private investment in the sector in the free zones.

The UAE’s electricity laws themselves do not impose any specific ownership restriction on foreign investors in the UAE, nor do they necessarily require government participation in the sector. As a matter of policy, in Abu Dhabi, although two or more foreign joint venture partners are permitted to own up to 40 per cent of a project company, the RSB (historically) and now the DOE, ensures that a foreign entity does not own more than 25 per cent of the market by capacity.

Most power companies in the UAE (with some exceptions such as UTICO) are either wholly or majority owned by the federal or respective emirates’ governments, and the sector is dominated by the state-owned water and electricity authorities. Of these, DEWA and DOE (formerly ADWEA) being the largest two, account for about 95.4 per cent of the UAE’s gross generated electricity. As of the figures available for 2016, ADWEA (now the DOE) accounts for approximately 62.1 per cent of the UAE’s gross generated electricity (at 80,527GWh), DEWA for 33.3 per cent (at 43,092GWh), Sharjah Electricity and Water Authority (SEWA) for 4.4 per cent (at 5,684GWh) and FEWA for about 0.2 per cent (at 293GWh).

\(^5\) Issued on 23 September 2018.
United Arab Emirates

Abu Dhabi

The DOE was established pursuant to the DOE Law, and is responsible for all matters relating to formulation, development and implementation of policies for the electricity sector in Abu Dhabi, including privatisation. As mentioned previously, the DOE has replaced ADWEA and RSB and has inherited all of their assets, properties, rights and obligations.

To date, a number of independent water and power producers (IWPPs) have been established as joint-venture arrangements between ADWEA and various international power companies as BOO (build, operate, own) projects, which include:

- Arabian Power Company;
- Emirates CMS Power Company;
- Emirates SembCorp Water and Power Company;
- Fujairah Asia Power Company;
- Gulf Total Tractebel Power Company;
- Ruwais Power Company; 6
- Shuweihat Asia Power Company PJSC; 7
- Shuweihat CMS International Power Company;
- Taweelah Asia Power Company; and
- Mirfa International Power and Water Company.

The ownership of the above-mentioned IWPPs is split 60:40 between ADWEA (or its subsidiaries) and the foreign investor. The project companies are usually structured as joint stock companies incorporated in Abu Dhabi. The most common ownership structure is one in which ADWEA (and henceforth the DOE) incorporates an intermediate holding company to own a 60 per cent stake, which is in turn held 10 per cent by ADWEA (and henceforth the DOE) and 90 per cent by the Abu Dhabi National Energy Company PJSC (also known as TAQA). 8 A few project companies have other ownership structures.

In early 2018 ADWEA had invited private-sector entities to submit expressions of interest to participate in a US$1.2 billion water desalination plant in Abu Dhabi (the Taweelah Desalination Plant). ACWA Power won the bid for the Taweelah Desalination Plant and has signed a power purchase agreement with EWEC. The construction of the project will commence in May 2019 with completion expected in October 2022. The project is held 60 per cent by the DOE and 40 per cent by ACWA Power.

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6 The Shuweihat S2 IWPP, owned by Ruwais Power Company was commissioned in October 2011, adding a further 1,507MW to Abu Dhabi’s power generation capacity and 100 million imperial gallons of potable water each day.

7 In February 2011, a PPA for the Shuweihat 3 power plant was signed between ADWEC (now EWEC) and Shuweihat Asia Power Investment BV, a company 60 per cent-owned by ADWEA (now the DOE) and 40 per cent by Sumitomo Corporation of Japan and Korea Electric Company (each holding 20.4 per cent and 19.6 per cent respectively). This plant has been operational since September 2014 and generates 1,600MW.

8 Jeffery Delmon and Victoria Rigby Delmon, International Project Finance and PPPs: A Legal Guide to Key Growth Markets 2012, Chapter 16, p. 26 (2012). TAQA, in which the DOE (formerly ADWEA) owns a 74.05 per cent ownership stake, was established under Abu Dhabi Decree No. 16 of 2005 and serves as ADWEA’s (now the DOE’s) investment arm in the emirate and abroad. Other Abu Dhabi government entities own a further 1.16 per cent of TAQA with the total government shareholding being 75.21 per cent. The remaining 24.79 per cent of TAQA is owned privately.
**Dubai**

DEWA was established as an independent public authority owned by the government of Dubai, responsible for the development and provision of utilities in the emirate. DEWA is managed by a board of directors whose members are appointed by Emiri decree.

DEWA is an integrated supplier owning and operating in all segments of the electricity market in Dubai. DEWA owns and operates 12 plants in the emirate whose individual capacities vary between 400MW to 2,200MW, with a total installed capacity of 10,413MW of June 2018. Although the Dubai government wants to promote private investment in its electricity generation sector, to date, all of the power generation capacity of Dubai, except for captive power produced by certain entities (e.g., Dubai Aluminium Company Ltd), is owned by DEWA.

In 2011 Dubai passed the Dubai Electricity Privatisation Law, which is broadly modelled on the Abu Dhabi Water and Electricity Law. The Dubai Electricity Privatisation Law authorises DEWA to establish project companies, by itself or in collaboration with third parties, for the generation of electricity. In 2015, Dubai Law No. 22 of 2015 on Regulating Partnership between Public and Private Sectors in Dubai (the Dubai PPP Law) was enacted, which governs the regulatory framework of public–private partnerships in Dubai. The Dubai PPP Law aims to encourage private-sector participation in the development of projects. It sets out, *inter alia*, the terms of partnerships between the public and private sector and conditions for approval of prospective projects.

To date, several independent power projects (IPPs) have been launched in Dubai. The first IPP is Al Hassyan 1 IPP, a 1,500MW gas-fired power plant, for which bids were solicited in December 2011. The project has, however, been deferred indefinitely.

In 2015, a consortium of ACWA Power and TSK Electronica y Electricidad SA won the bid to set up a 200MW photovoltaic plant (Shuaa Solar PV Project) in the second phase of the Mohammed bin Rashid Al Maktoum Solar Park (Solar Park) on the IPP model. The project has been operational since April 2017.

Subsequently, the Hassyan Clean Coal Project was launched by DEWA and the consortium of ACWA Power and Harbin Electric was awarded the project. In 2016, the major engineering procurement and construction contract for the Hassyan Clean Energy Project was awarded to Harbin Electric International and General Electric. The project is proposed to be operational by 2023.

Another development in 2016 was the selection of the consortium led by the Abu Dhabi Future Energy Company (Masdar), including the Spanish companies FRV (Fotowatio Renewable Ventures) and Gransolar Group for construction of the 800MW third phase of the Solar Park on the IPP model. The first phase of the project (200MW) is expected to be operational in the first half of 2018, followed by the second phase (300MW) in 2019, and the third phase (300MW) in the first half of 2020.

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10 The special purpose vehicle set up to establish the project is Company Shuaa Energy 1, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA Power and TSK.

11 The special purpose vehicle set up to establish the project is Hassyan Energy Phase 1 PSC, in which DEWA is a 51 per cent stakeholder and the remaining 49 per cent is held by the consortium of ACWA Power and Harbin.
As the fourth phase of the Solar Park, DEWA released an expression of interest in October 2016 to build the largest concentrated solar power project in the world of 700MW (CSP), based on the IPP model. The project has been awarded to ACWA Power and Shanghai Electric and is proposed to be commissioned in stages, starting from the fourth quarter of 2020. In March 2019, DEWA also issued a request for qualification for the 900MW fifth phase of the Solar Park, proposed to be commissioned in stages commencing in the second quarter of 2021.

In addition to the above, Mohd Abdulla Haji Yousuf Khoory & Co LLC (trading as Union Paper Mills) was granted an electricity generation licence in November, 2016 in relation to a 3MW biomass boilers’ facility at Al Quoz, Dubai.

In March 2017, Al Ghurair Resources Oils & Proteins LLC was granted a licence by RSB Dubai to generate electricity from an up to 8MW coal plant in Jebel Ali. DEWA is also developing a 250MW power station, which will use water stored in the Hatta Dam, which can total up to 1.7 billion gallons. The project is the first of its kind in the Arabian Gulf, with a lifespan of 60 to 80 years. There is limited information in the public domain regarding any tenders issued by DEWA to award the project to a private sector participant.

**Sharjah**

SEWA acts as the single point of sale for all power generated in Sharjah. In January 2019, GE and Sumitomo Corporation signed a 25-year power purchase agreement with SEWA to develop, build and operate a 1.8GW combined cycle power plant located in Hamriyah, Sharjah.

**Northern emirates**

FEWA is authorised under the FEWA Law to establish private power generation plants in the northern emirates. A number of projects are presently under development in these emirates but these are primarily owned in the public sector.

FEWA acts as the single point of sale for all power generated in the northern emirates. Electricity transmission and distribution networks within the northern emirates are also primarily owned and operated by FEWA. However, recently, TRANSCO has expanded its operations to assist FEWA in planning, developing and operating its water and electricity transmission assets in the northern emirates. In addition to FEWA, certain private power companies such as UTICO are involved in the generation, transmission and distribution of power in the emirate of Ras Al Khaimah.

In September 2017, FEWA invited expressions of interest from potential developers for the development of a 1.8GW coal-fired power plant in Umm al-Quwain or Ras Al Khaimah on the PPP model. The project has not yet been awarded to any bidder.

In December 2018, the government of Umm Al Quwain signed a cooperation agreement with FEWA for the construction of a 200MW solar power plant in Falaj Al Mualla, Umm Al Quwain. There is limited information in the public domain regarding any tenders issued to award the project to a private sector participant.

**iv Transfers of control and assignments**

Any transfer of control or assignment of an interest in an IWPP requires the consent of the relevant regulator.
Under the Abu Dhabi Electricity Laws, a licence may not be transferred unless it specifically permits its transfer. Prior consent of the DOE is required for any transfer (including the creation of security over assets of the licence holder), and the consent may be subject to such conditions as the DOE may consider appropriate.

Under the Dubai Electricity Privatisation Law, licensed entities are not permitted to transfer or assign their licences without the prior approval of RSB Dubai. In addition, licensed entities may not dispose-off, sell, lease or otherwise transfer, including granting of a security interest over, their ‘main assets’ without prior approval from RSB Dubai. Main assets are those movable and immovable assets necessary to conduct the regulated activities and operate the electricity generation facilities.

In addition, the Companies Law contains a statutory pre-emptive right in favour of existing shareholders in the case of limited liability companies and joint stock companies.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

The electricity transmission and distribution networks in the UAE are firmly owned and controlled by the state-owned water and power authorities, each of which enjoys a monopoly in its particular area of operation. These authorities are vertically integrated and operate in all three segments of the market.

Abu Dhabi

TRANSCO operates Abu Dhabi’s transmission networks. Until implementation of the DOE Law, TRANSCO was wholly owned by ADWEA. TRANSCO supplies electricity from the generation companies to the two distribution companies of Abu Dhabi, each of which was previously wholly owned by ADWEA, and now by the DOE. These are:

a Abu Dhabi Distribution Company (ADDC), which operates in the city of Abu Dhabi and the western region of the emirate; and

b Al Ain Distribution Company (AADC), which operates in Al Ain city and the surrounding areas.

In response to the power shortages faced in the northern emirates, TRANSCO has become involved in the planning, development and operation of electricity transmission networks in the northern region. TRANSCO’s involvement, given its resources and experience, coupled with ADEWA’s supply of its excess power, has largely alleviated the power problems faced by these emirates in the past.
Dubai

DEWA is the sole purchaser of electricity in Dubai and presently owns all the generation, transmission and distribution capacity of the emirate. DEWA’s transmission and distribution network is constantly being expanded as new real estate and industrial projects are set up across Dubai.

Over the past few years, DEWA has further enhanced the electricity transmission networks of the emirate. This includes construction of substations at Jebel Ali (December 2012), the International Media Production zone (February 2013), the Dubai Marina (May 2013), Seih Al Dahl (February 2014) and Dubai Academic City (2016). As of 2016, DEWA had 21 400kV substations, 222 132kV substations, 111 33kV substations and 31,961 11kV and 6.6kV substations. In February 2017, DEWA announced its plans to build 97 new 132/11kV substations over the next three years to be located at the Solar Park, and other locations to support the expansion of other power plants in Jebel Ali and Al Aweer. This was followed by an announcement by DEWA in April 2017 of its plans to build three new 400kV substations over the next three years. DEWA is also currently building three new 132/11kV substations with 45 kilometres of high voltage (132kV) cables for the World Expo 2020. The substations are named Sustainability, Mobility and Opportunity after the three subthemes of the Expo. The first of these substations (named Mobility) was commissioned in January 2018. As of 20 May 2018, fifteen 132/11 kV substations have also been commissioned in Salal, Saih Al Shuaib, Expo 2020, Warsan 1, Sheikh Mohammed bin Rashid Gardens, Palm Jumeirah, Al Markad, Nad Al Hammar, Business Bay and Zabeel 2.

Sharjah

SEWA is the sole purchaser of electricity in Sharjah and presently owns all the generation, transmission and distribution capacity of the emirate.

Because of the increased demands in electricity and energy, SEWA has recently embarked on improving and expanding its electricity transmission and distribution network on a large scale. SEWA has commissioned and inaugurated the Al Khan power transmission and distribution station (worth 105 million dirhams) in 2016, to ensure the reliability of power supply throughout areas such as Al Khan, Al Nahda and Al Taawun in Sharjah and has announced its plans of building three 132kv and five 33kv distribution stations in 2017.

Northern emirates

FEWA performs many of the same functions in the northern emirates with respect to electricity distribution and transmission as TRANSCO in Abu Dhabi and DEWA in Dubai. The northern emirates have been suffering insufficient power and electricity generation. For this reason and because of increased demand for electricity, FEWA has announced a number of new projects to expand and improve its electricity network. The notable projects are as follows:

- in May 2013, FEWA signed two contracts with the Saudi National Contracting Company Limited to commission a 33/11kV transmission station and upgrade a

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12 As of 2016, DEWA operates a network of overhead lines (1,125 kilometres of 400kV, 413 kilometres of 132kV and 113 kilometres of 33kV lines) and underground cables (23 kilometres of 400kV, 1,800 of 132kV, 2,052 kilometres of 33kV and 29,384 kilometres of 6.6 and 11kV lines) that are, in turn, connected to a distribution system of lower voltage substations and distribution lines.
number of 33/11kV and 132/33/11kV stations in the western region (Ajman and Umm Al Quwain), the central and eastern region (Fujairah and Dibba) and the northern region (Ras Al Khaimah);

b in 2016, FEWA inaugurated Al Hamra substation in Umm al-Quwain and plans future expansion of the same. In the same year, FEWA signed a memorandum of understanding with Siemens for the construction of a 2.2GW plant in the northern emirates to enhance electricity generation and distribution and another memorandum of understanding with Mitsubishi Electric for the installation of a number of 132/33/11KV substations in the northern emirates;

c in October 2017, FEWA invited bids from the private sector for the construction of a 132/33/11kV substation and cable works to be positioned in the northern emirates; and

d in August 2018, FEWA announced that it will build six new sub stations in the new residential areas of Ras Al Khaimah by 2020.

**Emirates National Grid**

The ENG project was launched in 2001 under a Cabinet Resolution No. 79/4 of 2001 ‘On the National Project of Linking the Power Grids’ to connect and enable sharing of power between the UAE’s seven emirates. The ENG project was launched by the Ministry of Energy with the purpose of enhancing integration between the various electricity and water authorities in the UAE, each of which contributed proportionately to the capital investment required to build the ENG. The ENG is owned by the following authorities in the proportions stated below:

a DOE (formerly ADWEA): 40 per cent;

b DEWA: 30 per cent;

c FEWA: 20 per cent; and

d SEWA: 10 per cent.

Dubai and Abu Dhabi’s power grids were connected by the ENG in the middle of 2006, whereas SEWA’s connection to ENG was completed in May 2007. Connection to the remaining northern emirates transmission networks was completed in April 2008.

On account of its larger production capacity and extensive distribution network, ADWEA (now the DOE) has increasingly been assisting the other emirates in meeting their power demand. ADWEA exported about 13,664GWh of electricity to other emirates via the ENG in 2012, up from 12,228GWh in 2011. Renewable energy sources such as solar and nuclear power will increasingly contribute to the ENG. Currently, the solar power is transmitted to the ENG from Shams 1 solar power plant and plans are under way for nuclear energy and further solar power to be transmitted from the Barakah nuclear energy power plant and photovoltaic panels respectively.

**The Gulf Cooperation Council (GCC) Grid**

The UAE is also connected to the rest of the GCC through the GCC Grid, through which it can trade electricity with the remaining GCC countries. About 56MW (peak time) of electricity was exported by Abu Dhabi to the GCC Grid in 2011 whereas 7MW (peak time) was imported in 2012. Ideas have been put forward to expand power grids to Egypt and European networks (through Turkey) and trade energy beyond the GCC region.
Transmission/transportation and distribution access

Abu Dhabi

The Abu Dhabi Electricity Laws require EWEC to purchase all power produced within the emirate. Although the Abu Dhabi Electricity Laws contemplate private ownership in all segments of the electricity supply chain, so far private ownership has been limited to generation only.

Dubai

The Dubai Electricity Privatisation Law prohibits a licensed entity from selling electricity to any entity other than DEWA.

Rates

Abu Dhabi

EWEC (formerly ADWEC), being the single buyer of electricity in the emirate of Abu Dhabi, purchases electricity from the power producers under long-term power and water purchase agreements (PWPAs) and sells it to the distribution companies via annual bulk supply tariff (BST) agreements. The distribution companies pay EWEC the BST for the electricity purchased and receive revenue from their customers and a subsidy from the government. TRANSCO is paid a transmission use of system (TUoS) charge by the distribution companies.

The components making up the electricity tariff in Abu Dhabi are the following:

a. BST, which is the charge paid by the distribution companies to EWEC for its generation costs (in turn paid by EWEC to power producers).
b. TUoS, which is the charge paid by the distribution companies to TRANSCO for use of its transmission network.
c. Distribution use of system, which is the fee that the distribution companies charge for use of their distribution network.
d. Sales cost, or the cost incurred by the distribution companies for serving customers for meter reading and billing.
e. Government subsidy, consisting of direct payments from the government to the distribution companies. The quantum of the subsidy allows the government to determine the electricity tariffs for different classes of consumers. The higher the subsidy, the lower the tariff charged.

The electricity tariff is determined by adding components (a) to (d) and subtracting (e).

The rates charged by the state-owned power companies (EWEC, TRANSCO, ADDC and AADC) are subject to government control, exercised via the DOE. The DOE sets their revenue target on the basis of which the control prices are determined. The remainder of the revenue is paid as a subsidy by the government to the distribution companies. All transactions between the power sector companies and any related tariffs are required to take place on the basis of their economic costs. This helps the government keep subsidies to a minimum.

The BST is calculated for each calendar year on the basis of parameters prescribed by the DOE. The calculation of BST requires the estimation of the costs for procuring and dispatching electricity generation to meet the forecasted demand. Starting in 2012,
the structure of the BST comprises three components (expressed in fils per kWh) charged on an hourly basis for electricity purchased at different times of the day, for ‘Fridays’ and ‘non-Fridays’ and in different months of the calendar year. These three components are:

a. a system marginal price charge estimated to indicate the short-term marginal costs (excluding backup fuel (BUF) costs) of providing units at different times of the day;
b. a BUF levy charge estimated to reflect the additional costs associated with the burning of backup fuel rather than primary fuel; and
c. a high-peak period charge assessed to cover the costs associated with the estimated capacity payments and charged only in the peak demand occurring months of June to September, inclusive.

The TUoS charge paid to TRANSCO covers the investment, operation and maintenance costs of the infrastructure of the transmission systems, excluding assets that are dedicated entirely to a particular customer. These include substations, overhead lines, cables and associated equipment. TUoS charges also cover the costs of the economic scheduling and dispatching of electricity generation.

The rates payable to the power generation companies are determined on the basis of the PWPAs entered by them with ADWEC (and going forward, EWEC). These PWPAs are further discussed below.

Contracts for power generation are awarded based on a competitive bidding process after the government invites tenders to meet the emirate’s power generation requirements. The bidding process is managed by the DOE starting from pre-qualification of bidders and issuance of request for proposals through to selection of the successful bidder.

Electricity rates paid by consumers in Abu Dhabi are subsidised. In fact, UAE nationals benefit from even greater subsidies than those given to expatriate workers. The rates payable in Abu Dhabi were substantially revised in 2015 with the introduction of a slab tariff scheme and an increase of 40–60 per cent in the applicable rates. The rates as published on the ADDC website for 2018 are divided according to consumer categories as follows:

a. UAE nationals (flats): 6.7 fils per kWh until 30kWh/day, 7.5 fils post 30kWh/day;
b. UAE nationals (villas): 6.7 fils per kWh until 400kWh/day, 7.5 fils post 400kWh/day;
c. non-UAE nationals (flats): 26.8 fils per kWh until 20kWh/day, 30.5 fils post 20kWh/day;
d. non-UAE nationals (villas): 26.8 fils per kWh until 200kWh/day, 30.5 fils post 200kWh/day;
e. industrial establishments (below 1MW): 28.6 fils per kWh;
f. industrial establishments (above 1MW): 27.0 fils per kWh at off peak hours, 36.6 fils per kWh at peak hours;
g. commercial establishments: 20 fils per kWh;
h. governmental offices: 29.4 fils per kWh; and
i. farms and ranches: 4.5 fils per kWh.

The rates for 2019 have not yet been published. With effect from 1 January 2018, VAT at the rate of 5 per cent has been implemented in the UAE pursuant to Federal Law No. 8 of 2017 (the VAT Law). Under the VAT Law, the 5 per cent VAT is payable by consumers on their electricity and water consumption. However, VAT is not applicable in respect of the municipality fee levied by the power companies in the respective emirates.
Dubai

The DEWA Law empowers the board of directors of DEWA to control electricity prices charged by DEWA, subject to the Ruler’s approval; however, since the promulgation of the DSCE Law, the electricity prices have been determined by the DSCE and DEWA now sets its prices in accordance with the DSCE’s directives. The DSCE Law empowers the DSCE to impose a ‘definite tariff based on cost when necessary’. The DSCE is also authorised to approve fees and tariffs on the services offered to the public by ‘energy service providers’ (meaning the power generation, transmission and distribution companies).

In 2011, Dubai passed Executive Council Decision No. 16 of 2011 on the Approval of the Electricity and Water Tariff in the emirate of Dubai (the Dubai Tariff Decision), which sets out the electricity and water tariffs for Dubai. The Dubai Tariff Decision provides for a slab tariff scheme and authorises DEWA to add the ‘fuel price difference’ to the electricity tariffs charged to consumers. The consumers are divided into (1) industrial (2) residential and (3) commercial. UAE nationals are subject to tariff rates equal to roughly one-third of the rate applied to other residential consumers.

DEWA has since 2011 increased electricity rates and pursuant to the Dubai Tariff Decision, introduced a variable fuel surcharge in its electricity tariff. The electricity tariff in Dubai now comprises the electricity consumption charges, the fuel surcharge and meter charge. The fuel surcharge component requires consumers to pay for any fuel cost increases using 2010 fuel prices as the benchmark, thereby passing on the risk of international fuel price fluctuations to the consumer. This has enabled the company to increase revenues, reduce demand growth and earn higher profits. The present fuel surcharge rate applicable in the emirate of Dubai is 6.5 fils/kWh. Since the introduction of the VAT Law, 5 per cent VAT is payable on the consumption of electricity and water in Dubai. As mentioned previously, VAT is not applicable in respect of the housing fee, sewerage fee and irrigation fee that DEWA collects on behalf of the Dubai municipality. Knowledge fee and innovation fee are also exempted from VAT.\(^\text{13}\)

IV ENERGY MARKETS

i Development of energy markets

The electricity market for private power producers in the UAE is comprised of the state-owned water and power authorities each of which acts as the single point of sale in their respective areas of operation.

Contracts for power generation are awarded on the basis of a competitive bidding process, administered by the DOE in Abu Dhabi, DEWA in Dubai, SEWA in Sharjah and FEWA in the northern emirates.

ii Energy market rules and regulation

Under the Abu Dhabi Electricity Laws, EWEC is required to contract with power producers for the purchase of all production capacity from licensed operators in the emirate. The DOE is authorised to allow ‘by-pass sales’ from power producers directly to eligible consumers provided that:

\(^{13}\) https://www.dewa.gov.ae/en/customer/services/consumption-services/value-added-tax-or-vat.
the first independent commercial power generation project in the emirates shall have commenced commercial operations;

b the majority of the shares in the company are privately owned; and
c the DOE issues a report stating that the energy market in the country is stable enough for it to be in the public interest that the sale of electricity by producers to eligible consumers be permitted.

To date, no ‘by-pass sales’ of electricity have been allowed by ADWEA (and now the DOE) in Abu Dhabi and all existing producers in the emirate are required to sell their production exclusively to EWEC.

Similarly, power producers in Dubai are obligated by law to sell their entire production capacity to DEWA.

All power generation companies in the northern emirates and Sharjah are required to sell their power production to FEWA or SEWA respectively.

iii Contracts for sale of energy

EWEC pays the generation companies the tariff agreed under the PWPAs. The PWPA serves both as a grant of concession and offtake agreement.14

The PWPA usually have a term of about 20 to 25 years from the commencement of commercial operations. Payments to IWPPs by EWEC (formerly ADWEC) under PWPA comprise three main components:

a capacity (or availability) payments covering the fixed costs of the plant (return on capital, depreciation and fixed operating and maintenance costs);
b operation and maintenance costs, paid when plant is available for production irrespective of whether and how much the plant produces; and
c output (or energy) payments for variable operation and maintenance costs, payable only for the electricity actually produced by the plant and dispatched.

The primary fuel used in the power generation sector in the UAE is natural gas, accounting for 90 per cent of all production. As is often the case in such models, fuel costs are pass-through, and EWEC is required to procure and supply fuel to the electricity producers under the Abu Dhabi Electricity Laws. EWEC acquires the natural gas from two sources, the Abu Dhabi National Oil Company and Dolphin Energy Limited (purchased from Qatar via a pipeline connecting both states) for onward supply to the power producers.

Power plants are required to stock diesel oil and crude oil as backup fuel. According to the standard PWPA, generation companies have to stock up enough backup fuel for their plants to run at full capacity for seven days.

PWPA payment rates under some of the agreements are subject to annual indexation against US and UAE inflation or the US$/dirham exchange rate.

EWEC is required by the standard PWPA to pay certain other supplemental payments to the IWPPs, such as start-up, shut-down costs and backup fuel costs. Some PWPA may also have provisions for payment by the relevant party of liquidated damages for delay in performance and of interest on late payments.

To date, DEWA has only signed three power purchase agreements:

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the first with a consortium led by ACWA Power and TSK, for the Shuaa Solar PV Project, recently amended to include the fourth phase of the Solar Park;  
the second with a consortium led by Harbin Electric International and ACWA Power for the construction of phase 1 of the Hassyan Clean Coal Project; and  
the third with Masdar, for the 800MW third phase of the Solar Park.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

High energy use, encouraged by subsidised energy prices and the construction of energy intensive industries such as aluminium smelting has resulted in the UAE having one of the highest per capita carbon footprints in the world. The development of renewable energy is therefore crucial in reducing the country’s carbon footprint and diversification of its economy away from fossil fuels. The UAE has announced that it aims to produce at least 7 per cent of electricity from renewable sources by 2020.

A number of showcase projects have been launched in Abu Dhabi and Dubai to kick-start the development of renewable energy in the country.

Abu Dhabi

Abu Dhabi established Masdar to spearhead the emirate’s renewable energy initiative. Masdar City, a project of Masdar on the outskirts of Abu Dhabi city, is proposed to be run entirely on renewable energy as a zero carbon emissions city. Masdar City has also won the rights to host the headquarters of the International Renewable Energy Agency.

Masdar currently produces 17,500MWh of electricity annually, at its solar photovoltaic power plant located at the Masdar City for supply of clean power to the project. It has also launched a carbon capture and storage project in the UAE.

Most significant is Masdar’s 100MW solar power plant at Madinat Zayed, which was inaugurated on 17 March 2013. Known as Shams 1, it is one the largest parabolic trough power stations in the world. This project is expected to be followed by the Shams 2 and Shams 3 solar power projects. Among other sustainable projects launched by Masdar in the UAE are Masdar City’s 10MW solar PV array in Abu Dhabi, Masdar City’s 1MW rooftop installations, a 100MW photovoltaic plant in Al Ain, a 30MW onshore wind farm on Sir Bani Yas Island, a grid-connected solar photovoltaic panel on Murawah Island, the Um Al Zomul solar photovoltaic plant, and a 543kWp photovoltaic plant that delivers energy to Rashid Abdulla Omran Hospital. With the success of its pilot project involving the installation of solar photovoltaic cells on 11 school and government buildings across the emirate, Masdar proposes to further expand the installation of solar panels to reduce dependence on hydrocarbon fuels.

Masdar is also actively expanding its international investments in clean renewable energy; some of its projects include the Seychelles wind power project (6MW), the Mauritania solar power project (15MW), Spain’s Gemasolar (20MW), Valle 1 and 2 solar power projects

15 Masdar is a wholly owned subsidiary of Mubadala Development Company, one of the Abu Dhabi government’s main investment arms.

16 The project company, Shams Power Company, is 80 per cent owned by Masdar and 20 per cent by Total SA.
(100MW), United Kingdom’s Dudgeon offshore wind farm (402MW), Jordan’s Tafila Wind Farm (117MW), Baynuna solar power project (200MW), Egypt’s Siwa solar photovoltaic plant (10MW), Samoan wind farm on the island of Upolu (1,500MW), Serbia’s Tesla wind farm (158MW), Tonga’s Vava’u island solar power project (512KW), Scotland wind farm (30MW) and the Noor 1 and Noor 2 solar photovoltaic plants (250MW) in Morocco. Masdar is also a 20 per cent stakeholder in the London Array wind farm in the United Kingdom, which produces 650MW of electricity. In partnership with the International Renewable Energy Agency, the Abu Dhabi government also granted US$57 million in loans to Argentina, Cuba, Iran, St Vincent and the Grenadines and Mauritania to finance renewable energy projects. Masdar is also involved with the UAE-Pacific Partnership Fund in developing renewable energy projects in the Pacific Islands. Currently, four new solar projects are under way in the countries of Kiribati, Fiji, Tuvalu and Vanuatu. An agreement was signed between Masdar and New Zealand to develop a solar photovoltaic power plant (1MW) in the Solomon Islands.

E.ON Masdar Integrated Carbon, a joint venture between E.ON and Masdar, develops and invests in carbon abatement projects in industry, power and oil and gas across Africa, Asia and the Middle East under the UN’s clean development programme.

A 100MW waste-to-energy facility is currently under development in Abu Dhabi (near the Mussafah Sea Port) by TAQA, in coordination with the Centre of Waste Management (Tadweer). The plant was scheduled to be up and running by 2017 but there is no update on its current status.17

Dubai

The DSCE developed the Dubai Integrated Energy Strategy 2030 and Dubai Clean Energy Strategy 205018 to enable Dubai to become a global centre for clean energy and green economy. In line with these strategies, Dubai aims to diversify its energy sources so that by 2030 it can fulfil 25 per cent of its energy demand from solar energy, 7 per cent from nuclear energy, 7 per cent from clean coal and 61 per cent from natural gas. By 2050, Dubai aims to fulfil 75 per cent of its energy demands from renewable energy sources.

As part of these strategies, in January 2012, Sheikh Mohammad Bin Rashid Al Maktoum, the Ruler of Dubai, launched the Solar Park. The Solar Park is expected to have a total installed capacity of 5,000MW by 2030. The project is being implemented by the DSCE in Dubai and managed and operated by DEWA. The first phase 13MW solar photovoltaic plant and substation was completed in 2013, followed by the second-phase Shuaa Solar PV Project in April 2017. The 800MW third phase was awarded by DEWA in June 2016 to a Masdar-led consortium and is expected to be operational in three phases commencing this year. DEWA also awarded the CSP project, as the fourth phase of the Solar Park to ACWA Power and Shanghai Electric, in September 2017.

In July 2013, Dubai launched a waste-to-energy conversion project through a landfill gas recovery plant at the waste collection site in Al-Qusais. To date, this is the first landfill in

17 https://government.ae/information-and-services/environment-and-energy/water-and-energy/energy-/waste-to-energy-
18 The Dubai Clean Energy Strategy 2050 was announced by the Dubai Supreme Council of Energy as part of its participation in the World Future Energy Summit held in Abu Dhabi in January 2017. The Dubai Clean Energy Strategy 2050 intends that 7 per cent of Dubai’s total power output will come from clean energy by 2020, 25 per cent by 2030 and 75 per cent by 2050.
the region to run its entire operation with electricity generated from landfill gas. In due course, the plant is expected to increase capacity from its current 1MW to 20MW by 2020. Plans to implement a similar project in the Jebel Ali landfill are also proposed by the government.

In 2013, DEWA and DSCE established Etihad Energy Service Company (Etihad ESCO), which will serve, notably, to retrofit existing buildings and lower the water and energy consumption of such buildings.

DEWA has launched the Shams Dubai Initiative, which aims to encourage energy efficiency by equipping residential and commercial buildings with solar panels and connecting the panels to DEWA’s electricity grid. In 2014, in line with this initiative, the emirate of Dubai issued Executive Council Resolution No. 46 of 2014 Concerning the Connection of Generators of Electricity from Solar Energy to the Power Distribution System in the emirate of Dubai (Resolution 46) to encourage the generation of electricity using solar panels. Resolution 46 enables DEWA consumers to supply power to DEWA’s grid by connecting their solar panels and the power supplied to DEWA can then be adjusted against the consumer’s electricity bill.

In 2015, Dubai established the Dubai Green Fund (Fund), worth US$27 billion, which provides easy loans to investors in the clean energy sector. DEWA will provide the seed capital for the Fund, with additional investment from the private sector, international banks and large investment companies.

In 2016, DEWA inaugurated one of the largest single rooftop arrays in the Middle East and North Africa region, a 1.5MW direct current photovoltaic generation project at the Jebel Ali Power Station, and successfully connected it to DEWA’s grid.

Currently DEWA is working to develop an Innovation Centre, equipped with the latest renewable and clean energy technologies to raise awareness on sustainability, while enhancing national capabilities and increasing competitiveness. The Innovation Centre will be equipped with the latest clean and renewable energy technologies, and will serve as a museum and exhibition for solar energy. The centre will also feature two solar testing facilities, the first will specialise in testing PV solar panels, while the second will focus on CSP. The centre is currently testing 30 photovoltaic panel types from global specialist manufacturers.

Dubai has also established the Dubai Carbon Centre of Excellence, responsible for encouraging and developing strategies towards reducing the emirate’s dependence on carbon fuels and reducing carbon emissions.

In January 2018, DEWA signed a memorandum of agreement with the GCC Interconnection Authority and the Belgian Dredging, Environmental & Marine Engineering Group towards building a 400MW pumped hydro storage power station in the Arabian Gulf, with a storage capacity of approximately 2,500MWh.

The Dubai Municipality also announced the world’s largest waste-to-energy project in the emirate’s Al Warsan area, in early 2018. The plant is designed to treat 1.82 million tonnes of solid waste annually, with a total capacity to generate 185MW of electricity. Construction of the plant is proposed to begin mid-2018 and be completed in time for Expo 2020.

**Sharjah**

Like Dubai, Sharjah launched SEWA 2020 Vision in 2016 to enhance power efficiency in sustainable development. SEWA intends to reduce power and water use by at least 30 per cent over the next five years (i.e., by 2020). To achieve this vision, SEWA has launched various projects, which include: setting up the first electric-vehicle charging station, completing a
solar-powered road lighting project in Al Saja’a and Al Barashi, and replacing the current electrical infrastructure with modern facilities such as a smart metering system and networks to save energy.

Bee’ah and Masdar have formed a joint venture under the name of Emirates Waste to Energy Company (EWEC) to develop waste to energy plants across the Middle East. The first project being undertaken by EWEC is in Sharjah to establish a facility with the capacity to treat more than 300,000 tonnes of municipal solid waste a year, and with a power generation capacity of 30MW. EWEC and SEWA entered into a power purchase agreement in May 2017 for this project. The project is expected to be commissioned in the third quarter of 2021.

In March 2019, Bee’ah also opened an industrial waste water treatment plant in Al Saj’ah, Sharjah, with a daily processing capacity of 300 cubic metres.

Northern emirates

In 2014, UTICO, a privately owned utility company, called for the construction of a new 40MW solar plant in Ras Al Khaimah. UTICO has also collaborated with Shanghai Electric to set up a clean-coal power plant project (270MW) in Ras Al Khaimah. Both projects have been deferred indefinitely.

Recently, FEWA installed 11,000 smart electricity and water metres in Ajman. Additionally, in 2016, FEWA announced a 1.3 billion-dirham funding budget to improve the electricity network in the northern emirates. FEWA is expected to expand 17 power stations and construct 25 power distribution stations in Umm Al-Quwain, Ras Al Khaimah and Fujairah.

In 2017, the Ministry of Climate Change and Environment signed a memorandum of understanding with Masdar and Bee’ah for developing a waste-to-energy conversion facility to serve Ras Al Khaimah and Fujairah.

FEWA is also in discussions with the government of Ras Al Khaimah for developing a hydroelectric power project in Ras Al Khaimah.

Nuclear energy


The UAE aims to produce a significant part (approximately 9 per cent) of its electricity from nuclear technology. The UAE released a nuclear policy in 2008 and has since then promulgated a regulatory framework for development of nuclear energy in the country. In addition to collaborating with the IAEA and the World Association of Nuclear Operators, the UAE has signed cooperation agreements with France (2008), Korea (2009), the United States (2009), the United Kingdom (2010), Australia (2012), Canada (2012), Russia (2012), Argentina (2013) and Japan (2013) for the development of peaceful use of nuclear energy.

The Federal Authority for Nuclear Regulation (FANR), the federal nuclear energy regulator headquartered in Abu Dhabi, was established in 2009 under Federal Law
No. 6 of 2009 Concerning the Peaceful Use of Nuclear Energy. The FANR is tasked with the responsibility of setting up the procedures and measures to be followed for the development of nuclear technology in the UAE. The FANR has issued regulations governing, *inter alia*, licensing, site location, design, construction, commissioning and operation, as well as standards for safety, transportation and storage facilities, radioactive waste management and physical protection of nuclear materials. The UAE has also created the International Advisory Board (IAB), an independent body consisting of independent international experts on nuclear energy who will offer guidance to the country’s nuclear programme on compliance with international safety, security and proliferation standards. The IAB is presently chaired by Hans Blix, the former IAEA Director General.

The UAE has been making rapid strides in establishing its first nuclear power station, the Barakah Nuclear Energy Plant (Barakah), in Abu Dhabi. The Emirates Nuclear Energy Corporation (ENEC), an Abu Dhabi government-owned company established by Federal Law No. 21 of 2009, is constructing Barakah, which will have a total capacity of 5,600MW. The project consists of the construction and installation of four 1,400MW reactors. As of December 2019, the project is more than 91 per cent complete and is proposed to be operational by 2020. Once the four reactors are online, the facility will deliver up to a quarter of the UAE’s electricity needs.

In 2016, ENEC signed a deal with TRANSCO to transmit nuclear power generated from Barakah through TRANSCO’s power lines to the ENG.

**Energy efficiency and conservation**

The UAE has one of the highest rates of electricity consumption per capita. This high usage is encouraged by the electricity and water subsidies given by the government to its citizens and in certain emirates to foreign expatriates. Dubai has progressively reduced and removed most of its electricity subsidies and Abu Dhabi is contemplating similar measures. Efficiency in energy usage is now being recognised as one of the key issues in trying to meet the country’s growing energy needs in a sustainable manner.

In 2010, Abu Dhabi imposed a mandatory rating system for construction of energy-efficient buildings in the emirate under the Estidama initiative. Starting from September 2010, all new development communities, private buildings and villas in the emirate are required to meet the minimum of one-pearl rating. All government led projects have been mandated to meet a two-pearl rating (the highest being a five-pearl rating). Masdar City, an eco-city project within Abu Dhabi, plans to expand its community and target a four-pearl Estidama rating to set an example as the leading energy efficient community.

The Dubai government has also enacted the ‘Green Buildings Regulations’ to encourage sustainable building practices. These regulations are enforced by the Dubai Municipality and apply to all new buildings constructed (including changes or additions to existing buildings) in the emirate. To this end, RSB Dubai has licensed nine energy service companies to retrofit more than 30,000 buildings in the emirate of Dubai to make them more energy efficient. Recently, the Emirates Green Building Council issued the technical guidelines for retrofitting existing buildings.

In 2016, Dubai and Sharjah launched projects to replace current infrastructure with energy efficient facilities. Both emirates are currently replacing street lights with LED lights. In Dubai, existing buildings are currently being retrofitted by Etihad ESCO while Sharjah is replacing and renovating its cables and meters.
In 2016, SEWA created a unit called the Conservation Department with a target to help people conserve 30 per cent of their utility bills over five years by adopting best practices in usage of electricity, water and gas.\(^9\) In Ajman, the Green Building Committee of the Ajman Municipality and Planning Department was also formed to support energy conservation efforts.

To attract foreign private investment in the sector, Dubai has created a free zone dedicated to the development of green technologies and energy conservation, and known as the Energy and Environment Park (EnPark). EnPark is also Dubai’s first master-planned community built on sustainable principles. In 2015, EnPark combined with another free zone, Dubiotech, to create Dubai Science Park.

Through recent investment in its transmission system, DEWA succeeded in reducing the percentage of line losses in its electrical network to 3.26 per cent in 2016 from 6.28 per cent in 2001 and has simultaneously increased the efficiency of its energy generation by 22 per cent between 2006 and 2014. As part of its demand growth management strategy, DEWA introduced a slab tariff that has been successful in reducing demand growth to 3 per cent despite a 5 per cent growth in end users in 2011. FEWA and the DOE also have slab tariffs in place for the northern emirates and Abu Dhabi respectively.

In 2018, FEWA signed a memorandum of understanding with Honeywell to drive sustainable development and green economy initiatives in the UAE’s northern emirates. Under this collaboration, FEWA will focus on amongst other things, driving significant energy savings (between 10–30 per cent) across a range of public sector buildings by adopting advanced energy efficiency technologies.\(^\text{20}\)

### iii Technological developments

Masdar has established the Masdar Institute of Science and Technology (MIST), a state-of-the-art research centre and university, in partnership with Massachusetts Institute of Technology. MIST is a graduate-level university that aims to provide solutions to issues of sustainability, focusing on advanced energy and sustainable technologies, through research.

Although it is a brand new institute, according to its website, over 30 research projects are currently under way, covering solar beam down, innovation ecosystems, smart grids and aviation biofuels. In addition, according to its website, a number of patents are already pending registration.

MIST is likely to play a leading role in development of advanced technologies in the UAE in the coming years.

In 2015, Masdar launched Masdar Solar Hub, a solar testing and research and development hub for photovoltaic and solar thermal technology. In the same year, DEWA Innovation Centre, which consists of a laboratory for research and development in clean energy, was inaugurated.

Once completed, the Solar Park is expected to include, _inter alia_, the following: a centre for innovation equipped with the latest renewable energy technologies, a research and development centre to conduct tests in relation to social and industrial needs for renewable

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United Arab Emirates

energy; two test technologies for photovoltaic panels and concentrated solar power; a solar testing facility; and a training centre and special conference centre for the exchange of information.

As of 2018, DEWA has signed a memorandum of understanding with Siemens to kick-off a pilot project for the region’s first solar-driven hydrogen electrolysis facility at DEWA’s outdoor testing facilities at the Solar Park in Dubai. In January 2019, DEWA and Siemens have also signed a memorandum of understanding to cooperate in research and development, exchange expertise and know-how, as well as building national capacities in energy technologies. The focus will be to pursue joint research and development activities in energy technologies including smart grids, the integration of renewable energy and distributed generation in the electricity grid, energy storage systems, the ‘internet of things’, using artificial intelligence in energy production unit, 3D printing and additive manufacturing, robotics, cybersecurity, robotics, and smart buildings, as well as building national capacities in the energy sector.21

VI THE YEAR IN REVIEW

The year 2018 marked the formation of the DOE and EWEC as a result of major restructuring of the energy and water sector in Abu Dhabi. EWEC and FEWA are said to be working towards unifying water production and power generation in the UAE.

The year also saw an increased number of private-sector companies striking deals with the electricity and water authorities in the emirates of Dubai, Abu Dhabi and Ras Al Khaimah for breakthrough projects. Power players like ACWA Power, Honeywell, Siemens, GE and Sumitomo Corporation are some of the key participants in the UAE energy space. This is in line with UAE’s goal of diversifying the economic revenues and boosting the economy after the oil prices fell in 2014. Of particular interest is the contribution of the private sector in the renewable energy sector. Currently, the UAE has the lowest cost of producing solar power in the world, which can largely be attributed to the collaborations between the UAE government and private companies. The contribution of the northern emirates in the energy sector is also on the rise this year as more activity in terms of new projects and smart grids is seen in 2018.

Renewable energy is playing a major role in the energy sector in the UAE as projects are increasingly aiming at harnessing the natural resources of the UAE, particularly solar power due to its geographical location. The different phases of the Mohammed bin Rashid Al Maktoum Solar Park are on track and the aim is for the park to be home to projects generating up to 5,000MW by 2030. This follows the Dubai Clean Energy Strategy 2050. With a view to promoting and adopting renewable energy, IRENA has announced an annual summer trainee programme aimed at training UAE-based students for a career in renewable energy and sustainability.

The UAE has been at the centre of innovation and technology and is now utilising technology in the power sector. This is evident from several collaborations and MOUs signed by the federal government and the government of Dubai with innovation companies dealing in technologies such as the ‘internet of things’, artificial intelligence and blockchain applications in the power sector for smart energy management.

VII CONCLUSIONS AND OUTLOOK

The UAE is geared up for and appears to be on track to meet its Energy Strategy 2050, which was launched in 2017. Backed by impressive technology, it is well equipped to meet the ever-increasing energy demands and bring smart and efficient energy production and usage. Energy efficiency is also a top agenda item for the UAE.

In September 2019, the UAE is hosting the 24th World Energy Congress, the World Energy Council’s flagship event attended by stakeholders, governments, industry experts and private corporations from across the globe. The aim of the Congress is for the attendees to share best practices and identify solutions for the key issues facing the energy sector globally. It will be interesting to see the resultant strategic partnerships, innovation, strategies and policies.

In addition to the focus on the energy sector at home, the UAE is also collaborating with and investing in other countries. Masdar has been deploying renewable energy technologies in a number of countries beyond the UAE, including Jordan, Afghanistan and Mauritania. IRENA and the Abu Dhabi Fund for Development have collaborated to support renewable energy projects in Rwanda, the Marshall Islands and the Caribbean. The UAE’s efforts are designed to enhance its global leadership position via renewable energy diplomacy that will support access to affordable and sustainable sources of power for millions of people in developing countries around the world.22

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Chapter 27

UNITED KINGDOM

Munir Hassan and Filip Radu

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I OVERVIEW

The United Kingdom has one of the most mature and dynamic electricity and gas markets. The country was a pioneer in the drive towards liberalisation, starting with the Energy Act 1983 that facilitated private competition within the generation and supply markets. The liberalisation was later bolstered by an ambitious privatisation programme in the late 1980s and 1990s, which led to the creation of wholesale markets where generators could sell electricity in real time. At present, the market is fully liberalised and privatised.

The United Kingdom has since pushed an energy agenda focused on decarbonisation, demonstrated by the country’s national 2020 renewable energy targets, which exceed those required under the European Renewable Energy Directive. This has resulted in strong growth for renewable generation over the past decade with subsidies providing attractive returns and investment opportunities. In the wake of the 2008 financial crisis, government policy has given increased attention to lowering the cost to consumers. In addition, concerns about the intermittent nature of renewable generators and their growing share of the generation profile of the United Kingdom have shifted policy focus towards ensuring security of supply. The result has been a reconfiguration of subsidy support mechanisms, with the twin aims of lowering the cost of new technologies, and incentivising the construction of baseload generation. This regulatory shift, together with the protracted uncertainty resulting from Brexit, has led to a slowdown in growth for new renewable projects and a converse increase in activity in the secondary market for operational renewable assets. However, there is sustained optimism in the energy sector, particularly in relation to emerging technologies such as battery storage (especially when such storage is co-located with existing renewable projects), carbon capture and storage, electric vehicles, smart metering/internet of things (IoT), and the opening up of transmission (onshore and offshore) projects to private investors.

1 Munir Hassan is a partner and Filip Radu is an associate at CMS Cameron McKenna Nabarro Olswang LLP.
II REGULATION

i The regulators

Gas and Electricity Markets Authority
The Gas and Electricity Markets Authority (GEMA) is the regulator of the gas and electricity markets in Great Britain. GEMA consists of a panel of individuals appointed by the Secretary of State for a specified term of not less than five years, but it is independent of government and has no stakeholder participation. GEMA’s duties are set out in the Gas Act 1986 (as amended) (the Gas Act), the Electricity Act 1989 (as amended) (the Electricity Act), and the Utilities Act 2000 (as amended) (the Utilities Act), and it has powers in relation to granting and administering electricity and gas licences, as well as concurrent authority with the Competition and Markets Authority (CMA) on the application and enforcement of certain competition rules. GEMA operates through its office, the Office of Gas and Electricity Markets (Ofgem), to which it delegates the day-to-day administration of its functions. Ofgem is therefore more commonly referred to as the regulator in common parlance.

GEMA’s objectives are enshrined in the relevant sections of the Gas Act and the Electricity Act. While these are varied and at times inconsistent, GEMA’s principal objective is to protect the interests of existing and future consumers in relation to electricity and gas and, wherever appropriate, to achieve this by promoting effective competition. An increasingly important feature in the regulated markets (particularly price-controlled networks and, more recently, supply markets) is GEMA’s duty to have regard to the need to secure that licence holders are able to finance their activities, which are the subject of obligations imposed under the Electricity Act (and, in practice, this is interpreted widely to cover the majority of GEMA’s functions). Although impractical to list here, the Electricity Act and the Gas Act contain additional matters to which GEMA must have regard when exercising its functions, for example, the need to ensure that all reasonable demands for electricity are met (i.e., ensure security of supply), the interests of consumers in the reduction of emissions of targeted greenhouse gases, the need to contribute to the achievement of sustainable development, etc.

On a day-to-day basis, Ofgem exercises GEMA’s powers to grant and modify licence conditions, monitor the activities of gas and electricity companies, and, where necessary, take enforcement action to ensure these companies comply with their statutory and licence obligations; however, Ofgem must follow its own guidelines and policies when taking such enforcement action, meaning its discretion is limited. As such, Ofgem’s enforcement guidelines provide that it will have regard to the principles of transparency, accountability, proportionality, consistency and will target regulatory activity only at cases in which action is needed, and to other principles that it considers represent best regulatory practice. Ofgem also exercises GEMA’s power to impose financial penalties on licence holders for breaches of such obligations, and there is the ability to benefit from discounts where there is an early settlement of the breach.

The regulatory framework is responsive to changes in the market through Ofgem’s ability to modify licence conditions. Appeals in respect of such modifications can be made to the CMA.

GEMA also has the power to modify the various industry codes that contain the detailed operational and technical rules governing the industry. This power is conferred by
the relevant licence condition under which a network operator (e.g., National Grid Electricity System Operator Limited (NGESO) or National Grid Gas plc (NGG)) is required to ‘own’ the code in question, and currently is not subject to any specific statutory constraints. Lastly, the Secretary of State has powers under the Electricity Act and the Gas Act to make secondary legislation to respond to more structural changes in the market.

**Northern Ireland Authority for Utility Regulation**

The Northern Ireland Authority for Utility Regulation, an independent non-ministerial government department, regulates the electricity, gas, water and sewerage industries in Northern Ireland. Its duties are to protect the short- and long-term interests of electricity, gas, water and sewerage consumers with regard to price and quality of service; promote a robust and efficient water and sewerage industry; deliver, where appropriate, high-quality services; promote competition, again where appropriate, in the generation, transmission and supply of electricity; and to promote the development and maintenance of an economic and coordinated natural gas industry.

**CMA**

The CMA is the United Kingdom’s (i.e., Great Britain and Northern Ireland’s) lead competition and consumer body established under the Enterprise and Regulatory Reform Act 2013 (ERRA). GEMA, as the energy regulator, has concurrent powers with the CMA with regard to the energy sector. ERRA requires sectorial regulators, including GEMA, to consider applying competition law before using their sector-specific powers. The provisions of the Competition Act 1998 and the Enterprise Act 2002 (the Enterprise Act) as amended by ERRA dealing with anticompetitive practices play a particularly important role and are jointly applied and enforced by GEMA and the CMA.

To improve the effectiveness of these concurrent powers, the CMA is required under ERRA to publish an annual report, in consultation with the sector regulators, on how the cooperation under the joint competition powers has worked.

Under the Enterprise Act, the CMA may investigate the functioning of competition within a market in the United Kingdom as a whole (as opposed to targeting specific actions of companies) and open an investigation where it has reasonable grounds for suspecting that any feature, or combination of features, of this market restricts or distorts competition in the supply or acquisition of any goods or services. In the case of the gas and electricity sectors, Ofgem may refer any of those markets to the CMA for a market-wide investigation or the CMA may direct Ofgem to transfer the case to it. The CMA conducted an extensive energy market investigation and on 24 June 2016 published its final findings and remedies. Although it found the wholesale electricity market was generally ‘working well’, it identified two aspects of the regulatory regime that adversely affected competition, namely: the absence of locational charging for transmission losses; and the mechanism for allocation of Contracts for Difference. Following the final CMA decision and issuing by the CMA of the Energy Market Investigation (Electricity Transmission Losses) Order 2016, NGESO raised a code modification to the Balancing and Settlement Code that sought to allocate transmission losses on a geographical basis.

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3 [https://www.gov.uk/cma-cases/energy-market-investigation.](https://www.gov.uk/cma-cases/energy-market-investigation.)
The CMA also has powers to hear appeals in relation to price controls set by Ofgem for network companies (price controls are explained further below in Section III). Two such appeals were brought in 2015 by British Gas Trading Limited (BGT), and Northern Powergrid (Northeast) Limited and Northern Powergrid (Yorkshire) plc (together ‘NPg’) in respect of the RIIO-ED1 price controls set by Ofgem. The result was the dismissal of two out of the three grounds of appeal for NPg and four out of five grounds of appeal for BGT.

**Health and Safety Executive (HSE)**

The HSE is the national independent regulator with regard to health and safety in Great Britain, which was established under the Health and Safety at Work Act 1974. It is responsible for the regulation and enforcement of workplace health and safety in Great Britain and for producing guidance and carrying out research in relation to occupational risks.

In Northern Ireland the role is performed by the Health and Safety Executive for Northern Ireland.

**Office for Nuclear Regulation (ONR)**

The ONR was established as a statutory public corporation on 1 April 2014 under the Energy Act 2013. It is responsible for the regulation of nuclear safety and security, including through granting nuclear site licences, across the United Kingdom. The ONR is also responsible for regulating the transport of nuclear materials and ensuring that safeguarding obligations for the UK are complied with. The ONR reports to the Department for Work and Pensions, although it also works closely with the Department for Business, Energy and Industrial Strategy (BEIS).

**Environment Agency**

Responsibilities in relation to environmental regulation in Great Britain have largely been devolved to governments in England, Wales and Scotland. For example, in England, the Environment Agency is a non-departmental public body sponsored by the Department for Environment, Food and Rural Affairs. It is responsible for protecting and improving the environment and promoting sustainable development in England.

In Wales, since April 2013, environmental and other natural resources-related matters have been the responsibility of Natural Resources Wales. With regard to electricity, the role of the environmental agencies is limited to pollution-related matters, and therefore mainly relate to conventional and nuclear generation, although additional environmental matters also arise in relation to consenting. In addition, the Environment Agency in England is also responsible for limiting and preparing for the impacts of climate change.

In Northern Ireland, the Northern Ireland Environment Agency is the body responsible for the protection conservation and promotion of the national environment.

**The Department for Business, Energy and Industrial Strategy and the Department for the Economy**

While not regulators, the Department for Business, Energy and Industrial Strategy (BEIS) (for Great Britain) and the Department for the Economy (DFE) (for Northern Ireland) are government departments responsible for setting the policies affecting the UK electricity and gas markets. The Secretary of State for BEIS is responsible for making decisions, setting policy and implementing legislation affecting the energy sector and is accountable on matters...
including security of supply and sustainability in Great Britain’s energy sector. There are some regulatory powers that are reserved to the Secretary of State directly. For example, the Secretary of State is authorised to make orders under the Electricity Act granting exemptions from the requirement to hold a licence, where certain criteria are met. Further, BEIS is responsible for formulating UK energy policy, which is implemented through legislation.

The corresponding government ministry in Northern Ireland is the DFE, which assumed most of the roles and responsibilities of the former Department of Enterprise, Trade and Investment.

ii Regulated activities
The regulatory framework in Great Britain operates through a system of legislation, licences and industry codes with an independent regulator responsible for the regulation of the sector and for enforcing any breaches of the rules. In the case of both electricity and gas, there is a prohibition on (and an associated offence for) carrying out the licensable activity without a licence (unless an exemption applies). Licences are granted by Ofgem to the entity carrying out the particular activity. In line with European Third Energy Package (IME3) unbundling and certification rules, a licensee may not hold a transmission, distribution or interconnection licence if it already holds a generation or supply licence.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009 provided for the establishment of Network Codes to help facilitate cross-border network access and market integration. Changes to the electricity sector are also under way pursuant to Regulation (EC) No. 714/2009 regarding harmonising the technical, operational and market rules governing the electricity grids; however, the European Commission has proposed in its latest fourth ‘winter package’ to recast this Regulation. Under this latter EU legislation, the European Commission, ACER, ENTSO have developed European Union-wide codes and guidelines for matters such as system operation (adopted), balancing activities (adopted), demand connection (adopted), grid connection for generators (adopted), capacity allocation and congestion management (adopted), and forward capacity allocation (adopted), among others.

Electricity
Unless an exemption applies, a licence is required for the following specified activities under the Electricity Act:

- a generation;
- b participation in transmission (defined to cover both the operation and ownership activities);
- c distribution;
- d supply; and
- e participation in the operation of an electricity interconnector.
From September 2012, providing smart metering services also requires a licence. The position regarding electricity storage is currently in development, and Ofgem is working with industry stakeholders to develop a regulatory definition for this technology (see more in Section VI).7

Gas

As with electricity, the Gas Act makes it an offence for an entity without a licence to carry out any gas transportation, interconnection, gas shipping, supply or smart metering (unless an exemption applies). For example, a licence to transport provides the right to convey gas through pipeline systems, while an interconnector licence gives the licensee the right to participate in the operation of a gas interconnector. The activity of gas shipping consists of buying gas from producers or importers and arranging for its transport (with gas transporters) via a pipeline system to a gas supply point, to then sell it on to gas suppliers.

Gas storage is subject to regulation but is not separately licensed.

A licence on its own does not give an entity the right to carry out other activities such as develop a project. Separate rights need to be secured in relation to land rights, planning requirements, decommissioning, etc., and the licensee would need to comply with other relevant legislation. In practice, this means obtaining authorisations from other regulatory bodies noted above (e.g., the HSE).

iii Ownership and market access restrictions

There are no energy-specific restrictions on foreign investment or ownership of energy companies or assets in the United Kingdom. However, an additional certification process requires Ofgem to assess, in consultation with the European Commission and the Secretary of State for BEIS, whether foreign ownership or control (meaning a licensee or a person who controls that licensee from a country that is not an EEA state) of transmission and interconnection infrastructure poses a security of supply risk in the United Kingdom or any other EEA state. In the event of a no-deal Brexit (or following the end of any transition period as provided for under the draft withdrawal agreement), the additional Ofgem certification requirements for transmission and interconnectors will apply to persons who are not from the United Kingdom.

In addition, the Secretary of State for BEIS has powers to take action in respect of transactions (including within the energy sector) on specific public interest grounds and where the relevant EU merger control thresholds have not been triggered.

In a similar vein, the unexpected decision to delay sign-off on final approvals for Hinkley Point C announced by the Conservative government in 2016 demonstrates that the executive branch has indirect levers for ensuring control over ownership of national critical infrastructure. In this instance, the government pointed to concerns over spiralling costs and security of supply to delay the signing of the final contracts, particularly the Contract for Difference awarded to Hinkley Point C securing the price of its output at £92.50/MWh (double the wholesale price at the time). In the event, the government approved the project; however, it proposed new legal safeguards mainly through a mechanism that will allow it

to prevent any transfer of ownership in UK critical infrastructure without its consent or knowledge, including that of EDF in Hinkley Point C (in this case through its holding of a ‘golden share’).

iv Transfers of control and assignments
There are no specific restrictions on control in a licence but assignments require prior written consent of the licensing entity. This is likely to require the incoming party to satisfy the Secretary of State that it is able to meet the licence obligations, and follows a similar vetting process as that for a new applicant. In practice, transfers are usually effected by transfer of the company that holds the relevant licences. The transmission, distribution and interconnection licences include obligations to ring-fence the regulated asset, which provides an additional level of control to Ofgem.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration and unbundling

Electricity
The Great British electricity transmission market was privatised in the early 1990s and has been fully unbundled, thus serving as a model for many other markets and jurisdictions (including for the EU’s Third Energy Package unbundling regime). In Great Britain, the legal separation of electricity supply and distribution activities was introduced by the Utilities Act as part of further restructuring of the market. As a result, distribution and supply are treated as separate licensed activities and licences may in principle not be held by the same person.

Under the provisions of the Third Energy Package TSOs must be certified as complying with ownership unbundling. This means that transmission interests (ownership and operation of transmission systems) must be separate from generation, and supply activities. As the UK position did not readily fit within the Third Energy Package model but was considered sufficiently well developed and independent to meet the aims of the Third Energy Package, a derogation applies in relation to vertically integrated UK TSOs pursuant to Article 9(9) (Section 10E (4), Electricity Act 1989). Scottish Hydro Electric Transmission plc (SHETL) and SP Transmission plc (SPTL), the Scottish transmission system owners, were granted certification on grounds of Article 9(9) subject to certain conditions and information-sharing restrictions.

Gas
A single regulatory framework applies across Great Britain in respect of the gas sector. Under the Gas Act there is no distinction between gas transmission and distribution activities: both activities are dealt with by the provisions relating to gas transportation.

ii Transmission/transportation and distribution access

Electricity

Transmission and distribution
In 2005, the British Electricity Trading and Transmission Arrangement (BETTA) introduced a single transmission system for the whole of Great Britain and divided the transmission role between a Great British transmission system operator (TSO), currently NGESO, on the one hand, and the existing transmission system owners on the other. Both activities – transmission
system operator and owner – are licensable and the transmission owners are required by law to make their respective transmission systems available to the TSO (i.e., NGESO), which is responsible for the real-time balancing of supply and demand and dispatch of generation.

The Electricity Act imposes a duty on transmission licence holders to develop and maintain an efficient, coordinated and economical system of electricity transmission; and to facilitate competition in the supply and generation of electricity. This primary obligation is supplemented by detailed provisions in the respective transmission licences dealing with issues such as compliance with industry codes, charging methodology, non-discrimination and competition issues (e.g., prohibition on cross-subsidies and separation of businesses).

NGESO, a private limited company within the National Grid Group, is the holder of a transmission licence in its capacity as transmission system operator for the whole of Great Britain; it does not own any transmission infrastructure. National Grid Electricity Transmission plc (NGET), a public limited company that is similarly part of the National Grid group, also holds a transmission licence in its capacity as owner of the transmission network in England and Wales; until 1 April 2019 NGET (in lieu of NGESO) performed the system operator function for the whole of Great Britain; however, from that date NGESO took over the role of system operator (only). NGESO is also the designated system operator for electricity interconnectors, where it performs system operator to system operator functions.

The respective transmission networks in northern Scotland and southern Scotland are owned by Scottish Hydro Electric Transmission plc and Scottish Power Transmission Limited. In Northern Ireland, the TSO is SONI Limited and Northern Ireland Electricity Networks Limited owns the transmission and distribution assets.

There is also a market for offshore transmission owners (OFTO) with increasing private investor participation. Ofgem has granted a number of licences for electricity transmission connections to offshore wind farms following competitive tenders. The regulator is currently running the OFTO Tender Round 6 process in relation to the Beatrice, Hornsea Project One (expected to be the world’s largest offshore wind farm, once complete) and East Anglia ONE offshore wind farms. To date, there are 14 operational OFTOs in place (having a total investment value of around £3.3 billion) for offshore wind farms with a total capacity of more than 5GW. OFTO Tender Round 6 is expected to attract a further £2 billion in relation to the new transmission assets for the three windfarms.

Ofgem is continuing to work with the government on developing competitive tenders for the design, procurement, construction and operation of new, separable, and high-value onshore transmission assets (designated as Competitively Appointed Transmission System Operators or CATOs). The first tender was projected to run in the early part of 2019; however, Brexit has delayed the development of the legislative framework (as a result of limited parliamentary time) and there is no clear indication as to when this may be completed. However, Ofgem has been considering whether the current legislative framework allows for the development of alternative models for the competitive delivery of new, separable, and high-value onshore transmission assets. Consequently, and as part of the necessary transmission reinforcement and connection works that NGET is required to carry out, for example, in respect of the Hinkley Point C nuclear project, Ofgem has consulted on two potential models to enable competition: (1) a ‘competition proxy’ model where Ofgem would set the transmission owner’s (TO) allowed revenue for a project in line with the outcome it considers would have resulted from an efficient competition for construction, financing and operation of the project, and (2) a special purpose vehicle model where the incumbent
TO would run a competition for the construction, financing and operation of the project through a project-specific company. To date, Ofgem has confirmed its preference to use the competition proxy model for the development of the Orkney and Shetland transmission link projects.

Each of the activities of transmission and distribution is to a large extent regulated through a series of industry codes. NGESO has the licence obligation to maintain and administer various industry codes dealing with the operation and use of the transmission system, including the Connection and Use of System Code (CUSC), the Grid Code and, in conjunction with ELEXON, the Balancing and Settlement Code (BSC).

The CUSC sets out the main rights and obligations in relation to the connection to, and use of, the national electricity transmission system, along with additional provisions on some ancillary and balancing services. The Grid Code sets out the detailed rules and requirements for matters such as connection conditions, dispatch, scheduling, operational liaison and safety coordination, and all material technical aspects relating to connections to, and the operation and use of, the transmission system. The governance of balancing and settlement arrangements is set out in the BSC, to which all generation and supply licensees must be party.

**Access**

Pursuant to its licence, NGESO must not discriminate between any persons or class or classes of person in the provision of use of the system or in the carrying out of works for the purpose of connection to the transmission system.

**Distribution network operators**

The electricity distribution system in Great Britain is organised along geographic lines with various regional monopolies. England and Wales are divided up between 12 distribution network operators (DNOs), while there are only two DNOs in Scotland and one DNO in Northern Ireland. As at April 2019, the monopoly distribution networks in Great Britain are operated by the following six companies: Electricity North West Limited, Northern Powergrid, SSE, SP Energy Networks, UK Power Networks, and Western Power Distribution. Ofgem also grants licences to Independent Distribution Network Operators (IDNOs), which are not geographically restricted. IDNOs compete with the monopoly DNOs by providing distribution services to large industrial and commercial customers such as the provision of connections and the design, construction and operation of small to medium-sized private distribution networks. The introduction of IDNOs and their ability to operate anywhere in Great Britain was intended to facilitate and bolster competition in the distribution sector, which has been (and to a large extent continues to be) dominated by the incumbent monopoly DNOs (which now, in law but not in practice, are no longer monopolies).

The DNO in Northern Ireland is Northern Ireland Electricity. Each DNO holds an electricity distribution licence and owns and operates the local electricity distribution system.

Pursuant to the Electricity Act, DNOs must develop and maintain an efficient, coordinated and economical system of electricity distribution and facilitate competition in the supply and generation of electricity. As with transmission, the electricity distribution licence conditions subject the DNOs to obligations such as non-discrimination in the provision of use of system and connection to system; safety and security; prohibition on cross-subsidies; business separation; and use of system and connection to system charges.
Similar to the obligations of NGESO under its transmission licence for its role as transmission system operator, under the terms of their distribution licence conditions, DNOs are each required to maintain and comply with the Distribution Code dealing with technical aspects relating to connections to and the operation and use of the licensee’s distribution system. In addition, one of the objectives of the licences and the codes is to facilitate competition in the generation and supply of electricity.

Access
Under the Electricity Act, DNOs have an obligation to make a connection between their distribution system and any premises when requested to do so by the owner of the premises or an authorised electricity supplier. Pursuant to the licences, DNOs must not discriminate between any persons or class or classes of persons in the carrying out of works for the purpose of connection to the licensee’s distribution system. In addition, DNOs must not discriminate in the provision of use of the system, and must on application made by any person offer to enter into an agreement for use of the distribution system.

Gas
Transportation
The Great British gas transmission network, the National Transmission System (NTS) – a high-pressure pipeline system that transports gas from entry terminals to various gas distribution networks (GDNs) and large industrial customers – is owned and operated by NGG. However, in May 2005, the Uniform Network Code (UNC) enabled companies other than NGG to own gas networks.

The UNC, which is maintained by the Joint Office of Gas Transporters, is the contractual framework that forms the basis of arrangements between the owners and operators of the gas transportation systems in GB and the users of those systems. Similar to the CUSC, the UNC is given effect by a shipper framework agreement, in the form of a contract between a gas transporter and an individual shipper user, by virtue of which they agree to be bound by the provisions of the UNC. In addition to entering into a shipper framework agreement, to become a shipper user under the UNC an applicant must satisfy certain admission requirements including the need to hold a gas shipper licence under the Gas Act.

Within their authorised area, gas transporters must develop and maintain an efficient and economical pipeline system for the conveyance of gas and, in so far as it is economical to do so, are under a duty to provide connection to that system and to convey gas. Additionally, the Gas Act imposes a general duty to facilitate competition in the supply of gas, and to avoid any undue preference or undue discrimination when connecting premises, or a pipeline system operated by an authorised transporter, to any pipeline system operated by the transporter, or in the terms on which the transporter undertakes the conveyance of gas by means of such a system.

The Gas Act is supplemented by detailed provisions on charging for connection and transportation services, standards of performance and system development obligations in the individual licences held by gas transporters.

Distribution
Similarly to the electricity distribution system, gas distribution in Great Britain is organised along geographic lines. There are eight GDNs in Great Britain covering different geographic
regions, which are medium- and low-pressure pipeline systems. Four of the GDNs (east Midlands, west Midlands, north-west England and the east of England (including north London)) are owned by Cadent (formerly part of NGG), while the remaining four GDNs are owned and operated by Northern Gas Networks Limited (north-east England (including Yorkshire and Northern Cumbria)), Wales and West Utilities Limited (Wales and south-west England) and SGN (Scotland and southern England (including south London)). On 8 December 2016, NGG announced it had agreed to sell a 61 per cent equity interest in its gas distribution business to a consortium made up of Macquarie Infrastructure and Real Assets, Allianz Capital Partners, Hermes Investment Management, CIC Capital Corporation, Qatar Investment Authority, Dalmore Capital and Amber Infrastructure Limited/International Public Partnerships. Similarly, on 17 October 2016, SSE announced it agreed to sell a 16.7 per cent equity stake in Scotia Gas Networks Limited (SGN) to wholly owned subsidiaries of the Abu Dhabi Investment Authority (ADIA), for a headline consideration of £621 million.

There are also a number of smaller gas transportation networks connected to the GDNs and owned and operated by six independent gas transporters (IGTs). The IGTs compete with each other and the GDN owners to provide gas transportation services. Unless an exemption applies, each IGT and GDN owner is required to hold a gas transporter licence.

Access

Under the Gas Act, gas transporters must, following any reasonable requests for connection, grant access to their pipeline system, in so far as it is economical to do so, convey gas by means of that system to any premises and comply with any reasonable request to connect to a pipeline system operated by another authorised transporter.

Access to the gas network is provided on an entry-exit basis instead of on a point-to-point basis. As access rights comprise entry and exit capacity at entry and exit points, shippers are required to book entry capacity and exit capacity to flow and take gas (there are relatively few entry points – principally gas terminals at which gas is landed from offshore fields).

iii Charges and tariffs

For electricity, the rates payable for connection to and use of the transmission system are set out in NGESO’s charging statements. The charges are broadly made up of the following:

a. transmission network use of system charges: to recover the revenue for the transmission system owners, that is NGET, the Scottish transmission owners, OFTOs, and in future CATOs;

b. balancing services use of system charges: to recover the cost of balancing the transmission system, and which depend on the amount of balancing required; and

c. connection charges: to recover the cost of installing and maintaining connection assets used by the party connecting to the transmission system. It takes into account the asset value, asset age and maintenance costs.

These are calculated in accordance with the relevant rules set out in the CUSC.

Ofgem is currently consulting on significant changes regarding the residual element of use of system charges both at transmission (TNUoS charges) and distribution (DUoS charges) level, as well as reform of embedded benefits for distribution-level generation (for more information see Section VI). Residual charges are intended to top up and make up for any deficit in the revenues allowed to be recovered by network companies after forward-looking
chargets have been levied. In contrast, forward-looking network charges are intended to send
signals to market for matters such as where to place generation, fuse size, etc., and these are
also being reviewed by Ofgem at the moment.

Price control

Ofgem regulates the prices for regulated assets (e.g., transmission and distribution networks)
pursuant to the licence terms of the given gas or electricity licensee. The current price control
model is known as ‘revenue = incentives + innovation + outputs’ (RIIO). These RIIO price
controls set out the revenue that the network companies are allowed to recover and what they
are expected to deliver, as well as specifying details of the regulatory framework over the eight
years from 2013 to 2021 for transmission and gas distribution, and from 2015 to 2023 for
electricity distribution.

The RIIO price controls are established against framework objectives set by Ofgem,
against which the network companies present a business plan detailing how they intend
to meet the objectives. The business plans are evaluated and approved by Ofgem. The
process is significant in terms of its scope and the time and effort it requires on the part
of many stakeholders. Consequently, it places major value on stakeholder engagement in
decision-making, efficient investment in services, innovation in networks and reduction of
carbon outputs.

Additionally, in its final report on the energy market investigation the CMA proposed
a transitional price cap for customers on prepayment meters from 2017–2020 and this has
been implemented by Ofgem. In addition, since February 2018, Ofgem extended this price
cap to vulnerable customers who receive the Warm Home Discount (WHD). However, on
1 January 2019 the Domestic Gas and Electricity (Tariff Cap) Act 2018 came into force,
which aims to protect all domestic customers on default tariffs (known as standard variable
tariffs or SVTs), including those on the WHD. However, even this primary legislation is
intended to be a temporary measure until 2023, by which point Ofgem intends to have
reformed the supply market so that it is more competitive.

iv Security and technology restrictions

While there are no specific security and technology restrictions in Great Britain, concerns
around national security, cybersecurity and data processing have become increasingly
common in the context of electricity and gas markets. These are typically dealt with through
bilateral contracts and protocols.

IV ENERGY MARKETS

i Development of energy markets

Electricity

Great Britain was among the pioneers of electricity-sector liberalisation from the mid-1980s,
when the Energy Act 1983 created the requirement for the state-owned area boards to offer
private generators access to their networks and to purchase the power they generated. Since
1991, the electricity market was privatised and the parties are now free to trade on the basis
of bilateral contracts (generally known as Power Purchase Agreements or PPAs).

Until 1 October 2018, Northern Ireland operated a separate wholesale electricity market
with a pool system, the single electricity market (known as the SEM), which is integrated
with the wholesale electricity market in the Republic of Ireland. However, on 1 October 2018 the SEM was reformed (through a project known as I-SEM) and transitioned to a bilateral contract market approach in order to comply with the IME3 EU Target Model and therefore facilitate market coupling.

At the time of writing, the UK as a whole has taken significant steps to implement the market coupling measures provided for in EU legislation, particularly those set out in Regulation 714/2009 and the network codes flowing out of that. By way of example, the UK has achieved the price coupling of its market within the EU-wide single day-ahead coupling project and continues to take steps in relation to the single intraday coupling project (known as XBID). However, without special arrangements being agreed between the UK and the EU, post-Brexit it is expected that the UK will have to revert to explicit auctions for selling cross-border capacity in the day-ahead time frame and will cease efforts to achieve price coupling for the intraday time frame.

**Gas**

Gas trades, subject to licensing requirements, can be traded by gas shippers within the NTS and at exit points on the gas system. This is usually done on the basis of standard-term contracts and in line with the requirements of the UNC.

The regulatory regime for gas has recently undergone reform through the development of the European Union-wide Network Codes. Regulation (EC) No. 715/2009 provided for the establishment of Network Codes to help facilitate cross-border network access and market integration. These Network Codes were thought necessary because of the increased interconnection and trade between EU countries and the need to manage gas flows. These Codes further inform the trading of gas.

**ii Energy market rules and regulation**

Energy market rules are largely set out in industry codes such as the Grid Code, the CUSC and the BSC. Compliance with these is governed through licence conditions, which require the relevant licensees to accede to and comply with those industry codes.

The BSC is particularly relevant for market trading. It seeks to ensure that total electricity generation and demand are balanced in real time, through a balancing mechanism operated by National Grid. It also quantifies imbalances between the amounts of electricity traded and the actual electricity generated or consumed, and regulates how these are paid for through a post-event imbalance settlement process operated by ELEXON. The BSC contains the rules and governance arrangements for the balancing mechanism and imbalance settlement processes. These arrangements, and the scope of the BSC, were subsequently extended to Scotland in April 2005 under the BETTA. Most electricity trading is done on the basis of industry standard contracts (grid trade master agreements (GTMAs) or an international swaps and derivatives association master agreement with a GTMA index) or by way of bespoke power purchase agreements between generators and suppliers.

Electricity trading is also subject to market transparency regulation and requires disclosure of price-sensitive information to the market. The Regulation on Wholesale Energy Market Integrity and Transparency (Regulation (EU) No. 1227/2011), initially adopted in December 2011, extends the concept of the Market Abuse Directive to physical gas and electricity, and requires market participants to disclose physical inside information, and to avoid attempted and actual market manipulation and abuse. More recently, the Markets in Financial Instruments Directive II has significantly narrowed the exemptions currently
available to commodity derivatives trading firms to ensure that ‘participants on commodity derivatives markets are subject to appropriate regulation and supervision’. It is worth noting that although the UK voted to leave the EU, the government has given assurances that it will continue to apply similar transparency rules at national level.

### iii Contracts for sale of energy

Generators, electricity suppliers, electricity traders and large customers can enter into commercially negotiated contracts to buy and sell electricity. The volumes (not commercial details) of the resulting trades are notified to the system and market operators, and any failure to achieve these notifications (called imbalances) are priced and settled. Trading takes place on a half-hourly basis with gate closure – set one hour ahead of real time – and participants notifying the system operator of their intended final physical position. After this point, no further contract notification can be made and settlement is based on positions at gate closure.

### iv Market developments

There are a number of changes affecting the UK energy and gas markets. For example, in electricity transmission in Great Britain, there are plans to introduce competitive auctions or models to build new onshore transmission lines. Ofgem is also continuing to run auctions for competition in offshore transmission.

There has also been a rise in the number of new entrants to the electricity supply markets. This is in line with government aims to decrease the dominance of the ‘big six’ vertically integrated utilities in the domestic supply market. However, this increase has been followed by an increasing number of resounding failures among smaller independent suppliers, whose business models proved too optimistic particularly in light of their failure to hedge against commodity price fluctuations.

The introduction of Great Britain’s capacity market in 2013 has also given rise to more attention being paid to demand-side response and how it is able to provide security of supply during times of system stress. In this respect, National Grid has launched a new demand-side response product, namely the ‘demand turn up’ ancillary service. However, this was discontinued in 2019 owing to feedback that the offline dispatch process, long notice period for delivery and small volume procured are significant barriers to increased utilisation of the service in its current form (therefore leading to ‘disappointing’ revenues for service providers). NGESO is currently reviewing alternative services for DSR.

### V RENEWABLE ENERGY AND CONSERVATION

#### i Development of renewable energy

The United Kingdom has a long-established renewable energy policy. At the national level, the United Kingdom, via the Climate Change Act 2008, has committed to a reduction of greenhouse gas emissions by 34 per cent by 2020 and 80 per cent by 2050 in comparison with 1990 levels.
The current main driver for renewable energy policy in the United Kingdom is the EU Renewable Energy Directive (RED). The RED aims to reduce the EU’s dependency on fossil fuels and to foster low-carbon and sustainable energy generation. EU Member States agreed under the RED to jointly achieve a target of 20 per cent of energy consumption from renewable sources by 2020. However, on 24 December 2018, the revised Renewable Energy Directive (Directive (EU) 2018/2001) came into force, which now sets a binding EU-wide target of at least 32 per cent by 2030. After the UK’s exit from the EU is effected, the entirety of EU legislation will be enshrined in national law (which will be known as ‘retained law’) by means of the operation of the European Union (Withdrawal) Act 2018 (subject to certain modifications that will be effected through secondary legislation and licence modifications). The transposition deadline for the revised RED is 30 June 2021 (at which point the RED will be repealed) and, therefore, the adoption of the new measures by the UK will depend on whether it has adopted the necessary laws and regulations to transpose the revised directive. Should that happen, the position on renewable energy consumption targets will remain unaffected regardless of the final Brexit position as the UK’s national renewables and decarbonisation targets exceed those imposed at EU level. However, there is concern that the government’s renewed focus on achieving industrial growth post-Brexit may render decarbonisation targets secondary to ensuring security of supply and low prices for large industrials. Not least, exit from the EU could potentially allow the UK to pursue an even more ambitious energy policy given that EU rules on state aid would cease to apply (however, such a departure from the EU’s state aid rules is unlikely given that the UK will have to observe such rules in order to secure maximum access to EU markets).

Contracts for difference

In Great Britain’s electricity sector, the primary support instrument for renewables is through contracts for difference (CfDs), which were introduced in 2013 by the Energy Act 2013 as part of the United Kingdom’s Electricity Market Reform (EMR) programme. Prior to its introduction, the main support measures available for low-carbon generation were in the form of the renewables obligation (RO), and feed-in tariffs (FiTs) for small-scale projects.

CfDs are 15-year contracts entered into between a government-owned company, the Low Carbon Contracts Company, and the successful low-carbon generators. The CfD mechanism works by setting a fixed price (strike price) thus reducing the generator’s exposure to electricity prices volatility and consequently the cost of debt and equity capital required for the investment. The first allocation round for CfDs took place in October 2014 and contracts were awarded to 27 projects in February 2015. The second allocation round for CfDs for the 2021/22 and 2022/23 delivery years took place in April 2017 and 10 projects were successful in obtaining contracts (three of these were subsequently terminated). The government estimated that the capacity delivered under the second allocation round cost up

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to £528 million per year less than it would have in the absence of competition. The third allocation round is currently planned to be held in May 2019 for less-established technologies (e.g., remote Scottish island wind).  

**Renewables obligation**

Support for renewable generation via the RO scheme was introduced in England and Wales in 2002 and administered by Ofgem. The RO scheme imposes an obligation on electricity suppliers to source a fraction of their electricity from renewable generation. Compliance with this obligation is shown by obtaining RO certificates issued to generators accredited on the scheme (with the number of certificates issued varying depending on the technology and the value of each certificate being broadly maintained through terms, such as a buyout price, set from time to time by the electricity regulator).

The RO has been closed to all new generation from the end of March 2017, but the process of closure has been implemented gradually through a series of legislative amendments, which imposed a cap on biomass, closed support to solar PV (large-scale in March 2015, and small-scale in March 2016) and closed support for onshore wind in May 2016. Early closures are subject to provisions of specific grace periods.

**FiTs**

The FiTs scheme was introduced to promote the deployment and use of small-scale (5MW and below) renewable and low-carbon generation. The FiTs scheme began operation on 1 April 2010 and is administered by Ofgem, which accredits generators, maintains the Central FiT Register of the accredited installations and monitors the reaching of deployment caps as well as compliance with the scheme.

Payments under the scheme are administered and performed by FiT licensees – meaning suppliers that join the FiT scheme either compulsorily (those supplying more than 250,000 domestic users) or voluntarily – which then pass on costs to consumers. A fixed payment is made under the FiT scheme for electricity that is generated on-site, the ‘generation tariff’, and another payment for any unused electricity that the generator exports to the grid, the ‘export tariff’.

Major changes to the FiT scheme were introduced at the end of 2015, including a reduction of tariffs, the introduction of quarterly deployment caps coupled with a default degression mechanism and an overall FiT budget limit.

On 19 July 2018, BEIS announced that the FiT scheme will be closed as of 1 April 2019 (subject to certain grace periods that will allow accreditation following that date).

**ii Energy efficiency and conservation**

The CRC Energy Efficiency Scheme was a mandatory carbon emissions reduction scheme that applied to large non-energy-intensive organisations. This was scrapped in March 2016 with effect from the end of the 2018/2019 compliance year.

The climate change levy (CCL) is a tax on energy delivered to non-domestic consumers that aims to incentivise increased energy efficiency. The government has introduced a 100 per cent exemption from CCL for energy used in certain energy-intensive (metallurgical
and mineralogical) industrial processes. Further, climate change agreements are voluntary agreements that allow eligible energy-intensive sectors to receive up to 90 per cent reduction in the CCL if they agree to meet certain energy efficiency targets.

Separately, the government has introduced the Renewable Heat Incentive (RHI) scheme aimed at promoting energy efficiency through encouraging renewable heat. The RHI is aimed towards levelling the cost of renewable heat with that of heating from fossil fuels by providing successful participants with periodic payments calculated in terms of £/kWh of eligible renewable heat or biomethane produced. The RHI was first introduced in November 2011 for non-domestic heating and subsequently expanded to include domestic heating support. Non-domestic RHI is governed by the Renewable Heat Incentive Scheme Regulations 2018, which came into force on 22 May 2018 revoking and replacing the Renewable Heat Incentive Scheme Regulations 2011 that previously governed the non-domestic RHI in Great Britain. Domestic RHI is underpinned by the Domestic Renewable Heat Incentive Scheme Regulations 2014 (as amended). Duration of support is 20 years for non-domestic and seven years for the domestic category.

### iii  Technological developments

The electricity and gas sectors continue to attract much interest in the development of new technologies. For several years, the UK government encouraged the development of industrial carbon capture and storage (CCS) and is funding a four-year coordinated research, development and innovation programme into CCS technologies. However, in late 2015 the government announced it was cancelling funding for a UK CCS commercialisation competition that would have made available £1 billion capital funding for the design, construction and operation of the UK’s first commercial-scale CCS projects. That said, on 28 November 2018, Energy and Clean Growth BEIS Minister Claire Perry announced a £20 million dedicated fund that will facilitate the development of carbon capture infrastructure at various sites, in addition to an existing funding of £100 million.

The UK government has also set up a Low Carbon Innovation Co-ordination Group to support innovation in energy technologies to meet the climate change goal of an 80 per cent reduction in greenhouse gas emissions by 2050. The group aims to maximise the impact of UK public sector support for low-carbon technologies.

The UK is emerging as a market leader and pioneer in the battery storage industry and there are ongoing efforts to create an appropriate legal and regulatory framework for this emerging technology. According to an all-party parliamentary group on energy storage, the deployment of 12GW of battery storage by the end of 2021 is achievable and would encourage post-Brexit growth.¹¹

### VI  THE YEAR IN REVIEW

Similar to events in 2017, many developments in the UK’s energy legislation and regulation over the past year have been reactive rather than proactive. This has been in large part due to the time- and resource-intensive process surrounding the UK’s departure from the European Union (Brexit), which has severely constrained the resources available to government, Parliament and the regulator to consider and implement forward-looking structural reforms.

Judging from the amount of media coverage, industry commentary and immediate impact for the consumer, the area that has witnessed the greatest degree of change has been the electricity and gas supply market. Arguably the headline event of 2018 was the imposition of the general electricity and gas price cap (i.e., price controls) for consumers on the default plan (the standard variable tariff or SVT). This represented a major change of philosophy for Great Britain’s policy in the supply market, given previous governments’ reluctance to intervene directly, and their converse preference to increase competition in that market as a remedy to increasing prices. However, the legislation that introduced the default price cap is also intended to be a temporary measure, lasting until further retail market reforms are completed.

That said, the imposition of the default price cap was merely one of many other measures announced or implemented in the supply sector, which notably has been hit by a spate of smaller supplier insolvencies due to failure to hedge (in a relatively volatile commodity market) and overly-ambitious business plans that failed to convert low entry-prices into volume-generated profits. For example, over the past year Ofgem has introduced licence restrictions on back-billing customers (i.e. bills may only be issued for consumption over the past 12 months), announced a wholesale review of supply licence conditions, together with BEIS kicked off a project to facilitate access to consumer data, continued the smart meter rollout and the transition to half-hourly settlement, etc. Cumulatively, the effect of all these measures and events has been to separate the wheat from the chaff, as the most sophisticated and well-run new and incumbent suppliers have been able to leverage the gaps in the market resulting from the significant number of insolvencies affecting the retail sector.

In respect of electricity networks, the signal event of 2018 was the creation of a new separate entity, NGESO, within the National Grid group to perform the role of Great Britain’s transmission system. This role was previously performed by National Grid Electricity Transmission plc (NGET), which was also (and continues to be) the owner of the England and Wales electricity transmission system; however, given the increasing scope and importance of the system operator’s functions over time, it was agreed by Ofgem and NGET that the creation of a legally separate entity would enhance its independence, and enable a more secure, competitive and flexible system. NGESO officially took over the role of electricity system operator on 1 April 2019, at which point NGET continued solely in its capacity as the transmission system owner for England and Wales.

The past year has also seen increased levels of activity for networks in relation to the next price control period. On 7 March 2018, Ofgem began its consultation for RIIO-2 gas distribution (GD2) and gas and electricity transmission (GT2/ET2). Since that initial step, Ofgem has published its framework decision in respect of RIIO-2 and detailed consultations on sector-specific methodologies for GD2, GT2, and ET2. Perhaps the most notable features of Ofgem’s proposals are the sharp reduction in the allowed cost of equity and innovative regulatory approaches. Ofgem is also proposing to continue using a cost of debt index to calculate the allowed cost of debt for network companies throughout the price control period. Given initial reactions to its proposals and the appeals brought by British Gas and Northern Powergrid as part of RIIO-ED1, it would be prudent to assume that there will be appeals in respect of RIIO-2, in some form. Although the current political climate (which has also resulted in relatively depressed economic growth) requires Ofgem to be seen as fighting the consumer’s corner, it is equally true that the move to a more flexible and
dynamic electricity system demands significant and extensive investment in infrastructure that requires commensurate returns on debt and equity so that network companies can finance their activities.

A major feature of the past year, which few expected, was the annulment by the General Court of the European Union of the European Commission’s state-aid approval for the capacity market in Great Britain following its judgment in the Tempus Energy case (note that the Irish SEM capacity market was unaffected, as it was the subject of a separate state-aid clearance, although that too was challenged and the case is ongoing). The effect of this decision was to suspend all capacity market payments and the collection of capacity market supplier charges (used to fund those payments). Holders of capacity agreements, whose financial models relied on that income, are now faced with a prolonged period of uncertainty while the European Commission carries out a formal investigation and finalises that exercise. Unless and until the state aid issue is positively resolved, this will require careful engagement between capacity agreement holders and financiers to ensure that any shortfall in capacity market income does not trigger a chain reaction that may have adverse unintended consequences for the entire energy sector in Great Britain. The suspension of the collection of capacity market supplier charges has also caused issues for electricity suppliers in terms of whether or not charges should still be levied on customers and what provision should be made for a potentially large back-payment once the state aid clearance is reapproved by the European Commission.

The UK renewables sector has continued to see a large amount of secondary market activity. That said, due to a number of significant offshore wind projects coming online (e.g., Rampion) or adding additional capacity, 2018 was yet another record year for renewables generation (with a commensurate record low for fossil-fuel generation). This has resulted in a 43 per cent reduction in carbon emissions since 1990, which has been assisted in part by record low levels of electricity consumption.

Brexit has also left its mark on the UK’s energy regulation, as government and Ofgem have had to put in place various electricity and gas statutory instruments and licence modifications to deal with the possibility of a no-deal Brexit. However, there have been other, less visible, effects of the UK’s departure from the EU that have impacted confidence levels, causing some investors to postpone final investment decisions in renewables and other energy infrastructure until the UK’s future relationship with Europe is set on a more certain footing.

VII CONCLUSIONS AND OUTLOOK

There have been few times in recent history when it has been as difficult as it is now to anticipate the direction of travel for UK energy regulation and markets. This is in large part due to the unexpected length and complexity of the Brexit process, which, depending on its outcome, may require the UK to promptly put in place alternative mechanisms to replace those supported under EU law or by virtue of the UK’s EU membership. At the time of writing, the UK had already extended its departure date from the EU once, and was in the process of seeking a further extension. Clearly, UK energy policy and legislation will require an inflexion point once clarity is achieved in respect of the UK’s enduring relationship with the EU so as to reboot the growth engine and future-proof this fast-evolving sector.

That said, there are some future developments that, all other things remaining the same, may be currently ascertained. For example, the highly anticipated CfD allocation round 3 is due to occur in May 2019, and will only be open to less-established technologies,
including for the first time remote island onshore wind (mainly aimed at the remote Scottish islands, e.g., Shetland). To the extent any Scottish island onshore wind projects are successful, this will also require transmission links to be built connecting those generators to the transmissions system on mainland Great Britain. For example, Ofgem has confirmed that Shetland generators obtaining a CfD is a condition precedent for its final approval of SHE-T’s final needs case for the planned 600MW HVDC link that will connect Shetland generators to mainland Great Britain.

The industry is expecting BEIS and Ofgem to provide legal and regulatory clarity regarding battery storage. Ofgem and BEIS have previously stated that they intend to achieve this by amending the Electricity Act 1989 and other relevant legislation to explicitly define electricity storage as a distinct subset of generation, and by the creation of a separate licence for storage. Evidently, a lot of parliamentary time has to date been taken up by Brexit considerations and it is unclear whether BEIS will be able to progress this workstream in 2019.

Market participants are also anticipating the conclusion of Ofgem’s Supplier Licensing Review process, which may be a first step towards reinstating full competition within the supply market by removing at least some of the retail price controls (e.g., the default tariff price cap). In a similar vein, Ofgem is also expected to make a decision on its consultation on TCR SCR proposals relating to reform of embedded benefits (and charges), as well reform of the residual elements of transmission network use of system charges.

Finally, generators and other capacity providers are keenly awaiting the outcome of the European Commission’s in-depth investigation into Great Britain’s capacity market, which was officially opened on 21 February 2019.
I OVERVIEW

Energy regulation in the United States is complex, broad and enforced by a variety of federal and state governmental entities. Further, it is continually evolving in response to global, national and regional events, supply/demand balance and other market shifts, political dynamics and priorities, and technological advances. As such, this chapter is intended to be an overview of the nature and scope of energy regulation and markets.

II REGULATION

i The regulators

Multiple federal and state agencies, departments and other governmental entities regulate US energy development, the ownership, control and operation of electric energy assets, and natural gas and oil production, gathering, transmission/transportation and distribution, including with respect to the rates, terms and conditions of wholesale and certain retail services, as well as energy market rules.

The Federal Energy Regulatory Commission (FERC) is an independent federal regulatory agency established by the United States Congress initially as the Federal Power Commission to license hydroelectric facilities and regulate wholesale sales of electric energy and natural gas and the transmission of electric energy or transportation by pipeline of natural gas in interstate commerce. Subsequently, FERC’s authority was expanded to include the regulation of interstate shipments of certain liquid fossil fuels via pipelines, including crude oil, petroleum products and natural gas liquids, such as propane and ethane. FERC’s authority is granted, and limited, by statutes, as amended over time, including the Federal Power Act of 1935 (FPA), the Natural Gas Act of 1938 (NGA), the Public Utility Regulatory Policies Act of 1978, the Natural Gas Policy Act of 1978, the Interstate Commerce Act of 1887, the Energy Policy Acts of 1992 and 2005, the Public Utility Holding Company Act of 2005 and the Department of Energy (DOE) Organization Act of 1977.

The Nuclear Regulatory Commission (NRC) is an independent federal regulatory agency established by Congress to formulate policies and regulations governing nuclear reactor and materials licensing and safety. The NRC’s authority is also granted, and limited, by statutes, including the Atomic Energy Act of 1954, as amended, and the Energy Reorganization Act of 1974, as amended.
DOE is an executive department created in 1977 via the DOE Organization Act whose current mission ‘is to ensure America’s security and prosperity by addressing its energy, environmental and nuclear challenges through transformative science and technology solutions’. DOE is led by the Secretary of Energy, a member of the President’s cabinet. FERC is within DOE, and, under the DOE Organization Act, DOE and FERC sometimes have overlapping and sometimes have separate authorities under their relevant organic statutes, including the FPA and the NGA. For example, under the NGA, DOE is responsible for issuing authorisations to import and export natural gas to and from the United States, including liquefied natural gas (LNG). At the same time, under the NGA, FERC is responsible for issuing authorisations to construct and operate LNG import and export terminals.

Numerous other federal agencies and departments regulate certain aspects of the US energy industry, including the Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) and Maritime Administration, the Environmental Protection Agency, the Army Corps of Engineers, the Commodities Futures Trading Commission, the Federal Trade Commission, and the United States Departments of Agriculture, Interior, State, Commerce and Justice. The production and gathering of crude oil and natural gas, the siting and construction of energy facilities (except hydroelectric and natural gas facilities regulated by FERC), and the distribution and retail sale of electric energy and natural gas are generally governed by individual state regulatory agencies. In many states, public utility regulation is carried out by public service commissions or public utility commissions (PUCs) or municipal agencies (or both). The jurisdiction of these state-based and locally-based regulatory agencies over energy companies is created by state constitutions and statutes and, like most state regulation in the United States, is also subject to the supremacy of the US government under the United States Constitution and federal statutes, except in certain limited circumstances.

ii Regulated activities

Many aspects of energy development, generation, production, transmission/transportation, and distribution in the United States are subject to some type of federal or state regulation. FERC regulates the rates, terms and conditions of wholesale sales of electric energy in interstate commerce and the transmission of electric energy in interstate commerce. FERC also regulates the rates, terms and conditions of natural gas and oil pipeline transportation services. Entities making sales of FERC-jurisdictional products or services obtain rate approval from FERC. FERC rates for electric transmission and interstate natural gas transportation and storage are typically either cost-based (i.e., based on the costs of providing the product or service including a reasonable return on equity investment) or market-based (i.e., negotiated or market-determined). Rates for petroleum pipeline transportation services may be based on historical and projected costs; and most pipeline rates are adjusted based on changes in a producer price index that measures the average change over time in the selling prices received by US producers for their output (plus a FERC-specified adjustment). FERC also regulates entities subject to its jurisdiction with respect to matters that may affect rates, including with respect to accounting, record-keeping and reporting, and, with respect to companies regulated under the Federal Power Act, direct issuances of securities and direct and indirect transfers of control over FERC-jurisdictional facilities.

Under the NGA, FERC is authorised to approve the construction and operation of new (and abandonment of existing) interstate natural gas pipeline and storage facilities and, as discussed previously, LNG import and export terminals. Owners of natural gas facilities
authorised by FERC (but not LNG terminals) may call on a federal power of eminent domain to condemn land on which to site approved facilities. As a condition to the construction of new natural gas pipeline and storage facilities, FERC may require natural gas companies to, among other things, conduct an ‘open season’, during which potential customers may subscribe to transportation or storage capacity on a non-discriminatory basis and existing customers may turn back capacity that may result in the downsizing or elimination of the new facilities. In exercising its rate jurisdiction over electric transmission facilities and oil pipelines, and in conjunction with its open access requirements, FERC has also required open seasons for some or all new or expanded capacity on certain electric transmission and oil pipeline facilities.

The NGA was amended in 2005 to expedite the licensing process for the construction of interstate natural gas pipelines and storage facilities, and to clarify and modify FERC’s review and approval of the construction and operation of LNG import and export terminals. The 2005 amendments also codified FERC’s existing policy of ‘light-handed’ regulation of LNG terminals by prohibiting FERC from regulating the rates, terms, and conditions of service for LNG terminals, but only until January 2015. Since passage of this date, FERC has not exercised any authority to regulate the rates, terms and conditions of service of LNG facilities, and instead has continued to allow LNG import and export terminals to charge market-based rates and to operate without imposing open access requirements. Under the FPA, FERC also has siting approval authority with respect to hydroelectric generating facilities to be constructed on navigable waterways. In 2005, Congress also gave FERC ‘backstop’ siting authority under the FPA to issue permits for the construction of transmission lines when the DOE designates important ‘national interest electric transmission corridors’ (NIETC) for geographical areas experiencing transmission constraints or congestion that adversely affects consumers, although the scope of FERC’s backstop siting authority and the DOE’s NIETC designation authority under the FPA remains unclear as a result of judicial decisions in the US Courts of Appeals.

PHMSA regulates the safety of most US pipelines and LNG terminals. Although PHMSA is responsible for enforcement of US laws setting minimum pipeline and LNG safety standards, PHMSA allows states to assume inspection and enforcement authority if the state has adopted the federal minimum standards into law.

Pipelines located in US waters on the Outer Continental Shelf are subject to regulation by the US Department of Interior. Prior to the Deepwater Horizon oil spill in the Gulf of Mexico in 2010, the Department of Interior’s offshore pipeline responsibilities were carried out by the Minerals Management Service; however, in 2010, these responsibilities were transferred to a new agency, the Bureau of Ocean Energy Management, Regulation and Enforcement, and then transferred again in 2011 to two new bureaus: the Bureau of Ocean Energy Management (BOEM) and Bureau of Safety and Environmental Enforcement (BSEE). Offshore pipelines located within three miles of the United States are also often subject to state regulation.

State PUCs generally regulate the distribution and delivery of electricity and natural gas to retail customers, including rates, terms and conditions for retail sales and distribution of electric energy and natural gas, and the safe and reliable delivery of electricity and natural gas to retail customers in the state. State PUCs may also regulate rates and operating conditions for intrastate natural gas pipelines and storage services and for intrastate deliveries of liquid fossil fuels by pipeline. Siting approvals for the development and construction of new energy facilities are often required at the state or local government level.
iii  Gathering, terminalling, processing, and treatment of natural gas and oil

In states where natural gas and oil exploration and development is active, state agencies often possess regulatory authority over gathering (typically the collection and movement of resources by pipeline from production wells to a centralised processing station or other central collection point) of natural gas and oil. Many states have adopted rateable take and common purchaser statutes, which generally require gatherers to take or purchase, without undue discrimination, production that may be tendered to the gatherer for handling or sale. These statutes are generally enforced by PUCs only when a complaint is filed. The processing and treatment of natural gas and the storage and terminalling of oil are generally not regulated. However, FERC may regulate a gathering or processing line if it determines that the primary function of the line is the transmission (not gathering) of gas; and it may regulate an oil pipeline terminal or storage facility if it determines the facility is a necessary component of the pipeline’s transportation function.

Regulation of the safety of natural gas gathering and processing facilities largely depends on the location and configuration of the facilities. Some facilities may be unregulated; others may be regulated by one or more state and federal agencies, to include the PUC, PHMSA, BSEE and the Occupational Safety and Health Administration.

iv  Ownership, market access restrictions and transfers of control

The Committee on Foreign Investment in the United States oversees foreign investment in existing companies and assets in the United States, with the President having ultimate authority to deny foreign investment that may adversely affect national security. Other than with respect to nuclear energy, there is little restriction on foreign ownership of energy assets in the United States under US energy-specific laws and regulations.

FERC approval is generally required for the direct transfer of natural gas facilities subject to FERC’s jurisdiction, including transfers that spin down or partially remove facilities from FERC’s jurisdiction (or reduce current services). In reviewing a proposed direct transfer of interstate natural gas facilities, FERC must determine whether the ‘abandonment’ of the facilities by the transferor is consistent with, and the ownership and operation of the facilities by the transferee ‘is or will be required by’ the ‘present or future public convenience and necessity’. In both cases, FERC applies a public interest test that considers matters such as the effect of the transfer on competitive conditions and existing customers and services, including rates.

FERC also regulates the direct and indirect transfer of ownership or control over electric transmission and generation facilities. In reviewing a proposed transfer of electric transmission or generation facilities, FERC must determine whether the transaction is consistent with the public interest, including the effects on competition (examining horizontal market power, vertical market power and barriers to entry), rates and regulation. FERC also considers whether the transaction would result in the cross-subsidisation of a non-utility affiliate of a public utility or the pledge or encumbrance of utility assets for the benefit of a non-utility affiliate of a public utility.

PHMSA requires operators of regulated facilities to provide notice of certain transfers, name changes, acquisitions and divestitures no later than 60 days after the event. New operators must also be fully in compliance with PHMSA regulations, including drug-testing, recordkeeping and operator ID requirements, upon owning or operating an active or idled pipeline.
Certain states also require that entities obtain PUC approval prior to the direct and, in some jurisdictions, indirect transfer of assets subject to the jurisdiction of the PUC. While many state statutes require PUCs to evaluate whether a proposed transaction is consistent with the public interest, PUCs vary as to whether they interpret their jurisdiction as requiring a showing that the transaction will not result in net harm to the public or a showing that the transaction will affirmatively provide net benefits to the public.

III TRANSMISSION/TRANSPORTATION AND DISTRIBUTION SERVICES

i Vertical integration, unbundling and open access

Over the past four decades, the federal government and many state governments have sought to replace traditional forms of cost-based regulation of services provided by vertically integrated monopolies with regulation designed to promote open access and competitive market forces.

Natural gas sector

Prior to the mid-1980s, the natural gas industry was fairly rigidly structured into three parts:

a producers that sold natural gas to pipeline companies;

b pipeline companies that resold and delivered that natural gas to distributors on a ‘bundled’ basis (combining the commodity cost of the natural gas with the cost of transportation service); and

c distributors that sold natural gas to retail customers.

Certain large industrial and electrical generating companies bought natural gas directly from producers or pipelines. And many local distributors had, in response to shortages in the 1970s, entered into long-term ‘take or pay’ contracts with pipelines for firm delivery of natural gas supplies for their customers. When gas prices fell in the 1980s, these distributors’ contracts required payment for minimum volumes at the historic, higher prices. In an effort to address this issue, and open natural gas markets to widespread competition, FERC issued Order No. 380 in 1984 voiding contractual requirements that distributors purchase minimum quantities of natural gas from pipelines. The next year FERC issued Order No. 436 encouraging voluntary ‘unbundling’ of pipelines (i.e., transportation services not tied to purchases of natural gas from the transporting pipeline or its affiliates). A few years later Congress passed the Natural Gas Wellhead Decontrol Act of 1989, lifting price controls on sales of natural gas by producers. FERC then adopted rules effectively deregulating the price of all other wholesale sales of natural gas. These orders were followed by FERC’s landmark ‘restructuring’ order (Order No. 636) in 1992. Order 636 enhanced natural gas market competition by imposing new open access rules, requiring interstate pipeline and storage providers to offer unbundled transportation services at tariff rates on non-discriminatory terms and conditions set by FERC, promoting development of market hubs, allowing flexible use of receipt and delivery point rights and release of firm transportation and storage rights, among other reforms. Also in 1992, the NGA was amended to effectively eliminate DOE permitting procedures associated with all natural gas imports, and exports to free-trade nations (coinciding with an agreement reached under the North American Free Trade Agreement to remove gas tariffs between the US, Canada, and Mexico).

FERC has continued to implement reforms to liberalise US natural gas markets by requiring compliance with new standards of conduct that prohibit transmission function
personnel from communicating non-public, competitively sensitive information to marketing personnel, requiring interstate natural gas pipelines to phase in standards adopted by the North American Energy Standards Board for internet-based information systems (to facilitate more efficient and transparent scheduling, reporting and use of available pipeline capacity), developing secondary markets for transportation services, market centres and customers’ rights to segment transportation capacity into forward and backward hauls and to use secondary receipt and delivery points on pipeline systems on a non-firm basis, and modifying scheduling timelines to facilitate improved gas-electric coordination. During these same periods, many states also modified the exclusive retail franchises of distributors to permit open access competition in the retail sale of natural gas, while continuing to regulate natural gas utility distribution services provided under exclusive franchises. These reforms led to highly competitive natural gas sales markets in the United States, where only pipeline transportation and distribution services, and certain storage services, are subject to rate regulation.

**Electric sector**

The electric sector in the United States was also initially dominated by vertically integrated franchised monopolies. Prior to the early 1990s, vertically integrated electric utilities with monopoly retail franchises owned and controlled most of the facilities used for the generation, transmission and distribution of electricity within their franchised service territories. Many vertically integrated utilities were widely traded stock corporations, although some were owned by the US or state governments. Numerous municipally owned or cooperatively owned utilities also distributed electricity at retail, although these publicly owned utilities were typically smaller and more likely to be dependent on investor-owned utilities for transmission services to access generation resources located outside their service territories.

In 1978, Congress enacted the Public Utility Regulatory Policies Act to encourage the deployment of renewable and energy-efficient technologies by requiring electric utilities to purchase electric power from generating sources using advanced technologies and eliminating all restrictions on the ownership of qualifying generating facilities. Non-utility companies demonstrated a high level of interest in building new power plants, which led in 1992 to Congress’s elimination of all ownership restrictions on facilities generating electricity for sale at wholesale. At the same time, both the federal government and many states began to liberalise their wholesale and retail electricity markets, including state efforts to have state-regulated public utilities divest some or all of their electric generation and federal efforts to make bulk power transmission facilities and distribution facilities available to others on an open access basis.

As part of the 1992 legislation, Congress amended the FPA to authorise FERC to order interstate transmission-owning public utilities to provide any electric utility, federal power marketing agency, or any other person generating electric energy for wholesale sale open and non-discriminatory access to their transmission facilities. As envisioned by Congress, such open access would allow bulk power consumers and suppliers to enjoy the benefits of competition in bulk power markets, as well as in those downstream retail power markets liberalised by states.

In 1996, FERC issued Order Nos. 888 and 889 to establish the foundation for the development of competitive bulk power markets by directing that bulk power transmission services be provided on an open access basis that is just, reasonable and not unduly discriminatory or preferential. Order No. 888 required that all FERC-jurisdictional
transmitting utilities in the United States file a \textit{pro forma} open access transmission tariff (OATT) and functionally unbundle their wholesale power services from their wholesale and retail transmission services. Order No. 888 also encouraged transmitting utilities to convey operational control of their transmission facilities to independent system operators (ISOs) or other independent regional transmission organisations (RTOs), which led to the formation of ISOs and RTOs in regions including the large majority of electrical load in the United States.

The \textit{pro forma} OATT requires transmitting utilities to provide open, not unduly discriminatory access to their transmission system to transmission customers and addresses the terms of transmission service, including the terms for scheduling service, curtailments and the provision of ancillary services. Transmitting utilities are permitted to vary from the required \textit{pro forma} terms of service if FERC finds that their proposed variations are equally or more conducive to the OATT’s open access objectives. Order No. 889 required codes of conduct governing how participants in the wholesale power markets should interact with transmission service providers and the establishment of electronic bulletin boards (open access same-time information systems) for the posting of details regarding available transmission capacity.

Since Order Nos. 888 and 889, FERC has issued a range of major orders updating and expanding its open access policies to address such matters as: the formation of and participation in RTOs; \textit{pro forma} procedures and agreements for interconnection of generation to the bulk power grid; changes to the \textit{pro forma} generator interconnection procedures and agreements to facilitate interconnection of wind generators; general rules to facilitate more open and transparent planning and use of wholesale transmission facilities; and most recently, general rules regarding transmission planning and cost allocation. FERC continues to consider whether reforms to its open access policies are necessary to eliminate possible barriers to the integration of wind, solar and other variable energy generation resources, as well as energy storage (e.g., batteries) and distributed energy resources, and to respond to market changes, including the growing deployment of small distributed generation resources, such as solar photovoltaic installations.

FERC’s Order No. 1000 adopted significant reforms of FERC’s transmission planning and cost-allocation rules established previously in Order No. 890. Order No. 1000 sought to address significant recent changes in the bulk power industry, including an increased emphasis on integrating renewable generation and reducing congestion, by implementing new policies to push transmission providers and planners to seek more reliable, efficient and cost-efficient solutions. The major reforms of Order No. 1000 include:

\begin{itemize}
\item[a] requiring each public utility transmission provider to participate in a regional transmission planning process that produces a regional transmission plan and regional and interregional cost allocation methods for planned projects;
\item[b] requiring each public utility transmission provider to amend its OATT to describe procedures for considering transmission needs driven by public policy requirements established by state or federal laws or regulations, such as state renewable portfolio standards;
\item[c] removing from FERC-approved tariffs and agreements any federal right of first refusal for incumbent utilities to build and own certain new transmission facilities; and
\item[d] improving coordination between neighbouring transmission planning regions.
\end{itemize}
Order No. 1000 also provides that transmission upgrade cost allocations must be roughly commensurate with the benefits received. FERC required public utility transmission providers to begin making filings with FERC during 2012 that proposed revisions to their transmission planning processes under their respective OATTs to comply with Order No. 1000. Throughout 2013, FERC issued orders regarding some of these compliance filings in which it accepted and rejected various proposed revisions, including rejecting a number of proposals to retain certain types of rights of first refusal for incumbent transmission providers to build and own transmission projects eligible for socialised cost recovery. Various aspects of Order No. 1000, including its directives on cost allocation and rights of first refusal, were appealed to the US Court of Appeals for the District of Columbia (DC Circuit). In August 2014, the DC Circuit issued a unanimous decision affirming Order No. 1000. FERC continues to face significant challenges regarding Order No. 1000, its cost allocation principles and the implementation of those principles.

Over the past several years, the US electricity industry has evolved to become more dependent on natural gas caused by relative decreases in natural gas prices along with increasing environmental regulations under various federal laws leading to coal plant retirements. In addition, the increasing rate of penetration of intermittent renewable generation resources often requires natural gas-fuelled generation as a reliability backstop. The increasing reliance on natural gas for electricity generation, together with severe weather experiences across the United States in recent years, have continued to put pressure on the existing natural gas transportation infrastructure and highlighted several issues with respect to how the natural gas and electric industries interact. After several years of technical conferences and public comments on these issues, in April 2015, FERC issued Order No. 809, entitled ‘Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities’, adopting proposals submitted by an industry forum to modify the scheduling practices used by interstate natural gas pipelines to schedule natural gas transportation service and provide additional contracting flexibility to firm natural gas transportation customers through the use of multiparty transportation contracts and revised nomination timelines. FERC also directed each FERC-jurisdictional RTO and ISO to propose tariff revisions to coordinate its day-ahead energy market with the scheduling practices adopted in Order No. 809 or to show cause why its existing scheduling practices need not be changed.

**Oil and liquids sector**

Unlike interstate natural gas pipelines, oil pipelines engaged in interstate commerce have been regulated as common carriers (not public utilities) since the Interstate Commerce Act was extended to oil pipelines in 1906. As common carriers, oil pipelines must provide service to all customers without ‘undue discrimination’ or ‘undue preference’ to any customer, including affiliated customers. The prohibition on undue discrimination and preference extends to periods when the pipeline is in ‘pro-rationing’, namely, the situation in which the pipeline must curtail specific shipments when customers’ nominations exceed available capacity.

For most of the twentieth century, the vast majority of oil pipeline mileage was owned by major oil companies with vertically-integrated production, transportation, refining and distribution operations. This situation began to change, however, in the latter part of the century in light of two developments. First, a change in US tax laws in the 1980s allowed companies engaged in (among other sectors) the transportation and storage of natural resources to be organised as master limited partnerships (MLPs), which provide certain tax advantages
to their investors and, hence, make investments in those sectors financially attractive. Second, in 1996, FERC began issuing declaratory orders that approved then-novel rate and tariff structures that enhanced pipeline developers’ ability to finance new pipelines. Specifically, when new or expanded oil pipeline capacity has been offered to all prospective shippers in a FERC-approved ‘open season’, FERC’s orders provide advance regulatory approval of pipelines’ long-term contract (‘committed’) rates and tariff structures that need not be supported by cost data. These two developments facilitated the development of pipelines by independent entities. Today, while many pipelines are still owned by vertically-integrated oil companies, tens of thousands of oil pipeline miles are also owned by non-integrated companies.

ii Rates
Economic regulation of most of the bulk power transmission system in the continental United States is administered by FERC, including regulation of the rates, terms and conditions for the transmission of electric energy in interstate commerce. Most FERC-regulated transmission services are provided at embedded cost-of-service rates that provide a return of investment as well as a FERC-determined reasonable rate of return on common equity. FERC also has permitted ‘merchant’ transmission projects (i.e., transmission that is not included in a cost-of-service rate base) to charge negotiated rates for transmission service.

In 2005, Congress amended the FPA to direct FERC to develop rate incentives to encourage certain transmission development. In 2006, FERC issued regulations to provide on a case-by-case basis a variety of cost-of-service rate incentives for new transmission projects that improve reliability or reduce cost. These incentives include incentive rates of return on equity for new investment, use of a hypothetical capital structure during construction, full recovery of prudently incurred construction work in progress in rate base during construction, full recovery of prudently incurred costs of abandoned projects, and accelerated depreciation. To obtain one or more of these incentives an applicant must show that there is a nexus between the incentive being sought and the risks associated with the investment being made.

Since 2000, FERC has also permitted certain merchant transmission projects to charge negotiated rates for transmission service under OATT-based transmission service agreements. Initially, FERC required merchant transmission facilities to hold open seasons for the full capacity of a planned project. Beginning in 2009, FERC permitted certain merchant transmission project developers to allocate some portion of transmission capacity (generally not more than 75 per cent) through pre-subscription to ‘anchor customers’, who provide upfront or assured ongoing payments through long-term transmission service agreements to facilitate project construction. The remaining project capacity not committed to anchor customers will be made available to later customers selected through an open season process detailed in the project’s OATT and these customers will be entitled to obtain service under terms and conditions generally comparable to those available to anchor customers. Since 2013, FERC has permitted merchant transmission developers to avoid formal open season requirements and allocate up to 100 per cent of the capacity on a transmission project to a single customer, including an affiliate, if the developer broadly solicits interest in the project from potential customers and demonstrates to FERC that it has satisfied certain solicitation, selection and negotiation process criteria.

Rates for interstate natural gas transportation and storage are generally based on costs, including a reasonable return. Rates for service are established for new facilities when FERC certifies construction. Pipelines may change the rates based on a showing that a
new cost-based rate is ‘just and reasonable’, and FERC or other affected parties may require prospective rate adjustments by showing that the existing rates are unjust and unreasonable. In 2009, FERC began a systematic and in-depth review of cost and revenue information that must be filed annually by pipelines, leading to the initiation of rate investigations of certain pipelines based on data suggesting that these were over-earning. FERC has continued initiating such investigations, typically targeting a few pipelines once each year or every other year. Most recently, in connection with changes in US tax law, FERC has initiated proceedings requiring reporting of updated cost and revenue data and has indicated that it will initiate rate investigations where these data suggest over-earning (unless the pipeline files to voluntarily reduce its rates).

Gas pipelines and storage companies are permitted to offer discounts below the maximum, cost-based rates approved by FERC (also referred to as the ‘recourse rates’) in order to meet competition. Any rate discounts offered by an interstate natural gas company must be offered on a non-discriminatory basis to all similarly situated customers. Between rate cases, the natural gas company must bear the cost of any revenue shortfalls attributable to discounts (i.e., it cannot charge higher rates to other customers to make up revenues lost because of discounting). Interstate pipelines and storage companies may also negotiate rates for services either above or below the recourse rate, as long as the customer retains the option to take service under the recourse rate. Independent storage companies are often permitted to charge competitive market-based rates based on a demonstration that they do not have significant market power.

For interstate deliveries, FERC-jurisdictional pipelines that transport fossil fuel liquids (oil pipelines) may charge cost-based rates; or they may charge market-based rates if adequate competition is proven to exist in the pipeline’s origin and destination markets. FERC-regulated oil pipeline rates may be changed annually based on the US Producer Price Index for Finished Goods, plus a margin established by FERC every five years (currently 1.23 per cent). If, however, oil pipeline indexed rates become significantly higher than a cost-based rate, or any annual increase is substantially greater than actual cost increases, FERC may adjust the rates. FERC allows greater flexibility in rates, terms and conditions of service for interstate service using new or expanded oil pipeline capacity if offered to all shippers and prospective shippers in an open season. FERC permits oil pipelines to offer priority service (i.e., service not subject to pro-rationing during normal pipeline operations) for up to 90 per cent of new capacity if contract (‘committed’) shippers pay a premium over ‘uncommitted’ (walk-up) rates, and all shippers had an opportunity to contract for the new capacity in an open season.

iii Security and technology restrictions

Prior to 2005, the United States relied on voluntary compliance by participants in the bulk power industry with reliability requirements for operating and planning the bulk power system coordinated through the North American Electric Reliability Corporation (NERC) and various related regional entities. In 2005, Congress responded to a widespread August 2003 blackout throughout the northeastern and midwestern United States (and parts of Canada) by amending the FPA to provide for a system of mandatory, enforceable reliability standards to be developed by a FERC-certified ‘Electric Reliability Organisation’ (ERO), subject to review and approval by FERC. For purposes of approving and enforcing compliance with reliability standards, FERC has jurisdiction over the FERC-certified ERO, any regional reliability entities, and all users, owners and operators of the bulk power system, including
public and governmental entities not otherwise subject to FERC jurisdiction under the FPA. FERC certified NERC as the ERO and in various subsequent orders has defined the bulk power system and approved a number of reliability standards proposed by NERC.

Federal law sets minimum safety standards for all natural gas and hazardous liquids pipelines, and provides for regulation of these facilities by PHMSA. PHMSA regulates pipeline facilities pursuant to its pipeline safety programme, which is implemented in cooperation with the states. Although PHMSA has the authority to regulate all interstate pipelines, it may allow a state to act as its agent, subject to certain limitations. Also, states adopting laws meeting or exceeding the federal minimum safety standards may obtain a certification from PHMSA to regulate intrastate pipelines. If a state’s law does not meet the federal minimum safety standards, PHMSA may decertify the state or exercise backstop authority to inspect and enforce federal pipeline safety laws. States are permitted to adopt and enforce standards that are more stringent than the federal minimum standards, which in many cases are overseen by each state’s PUC. The security of LNG waterfront facilities and deepwater ports is regulated by the US Coast Guard pursuant to a number of federal laws, including the Maritime Transportation Security Act, the Ports and Waterways Safety Act, the Magnuson Act and the Deepwater Port Act.

Federal law and agency-specific regulations require that owners and operators of energy facilities protect sensitive security and critical energy infrastructure information from disclosure to the public, including electronic copies of such information stored in company operating systems, databases and computers. The United States has not currently adopted mandatory cybersecurity standards for pipelines, storage facilities or LNG terminals, although in response to growing concerns about cybersecurity and recently reported cyberattacks on major pipelines, new legislation and new rules are being considered and a new DOE Office of Cybersecurity, Energy Security, and Emergency Response was established in 2018. The electric, natural gas and oil industries are voluntarily implementing measures to maintain security and are cooperating with federal agencies to develop and implement safeguards.

IV ENERGY MARKETS

i Development of wholesale electric energy markets

Throughout certain regions in the United States, ISOs and RTOs operate transmission facilities and administer organised wholesale electricity markets. FERC has prohibited any one set of market participants (including transmission owners) from controlling decision making within an ISO or RTO. FERC’s Order No. 2000 imposed significant regulatory requirements upon ISOs and RTOs regarding the independence of an energy market administrator, the performance of the energy markets and the elimination of discrimination. FERC leaves considerable discretion to market participants to determine an ISO’s or RTO’s governance structure, geographical scope and type of market services.

The following seven ISOs and RTOs are currently operating in the United States: PJM Interconnection, LLC (PJM), New York Independent System Operator Inc (NYISO), ISO New England Inc (ISO-New England), Midcontinent Independent System Operator Inc (MISO), Electric Reliability Council of Texas (ERCOT), Southwest Power Pool and California Independent System Operator Corp (CAISO). Of these RTOs, only ERCOT is not subject to FERC’s regulatory oversight under the FPA, as ERCOT is deemed to be electrically isolated from the rest of the transmission grid in the continental United States.
Similarly, Alaska and Hawaii are not subject to FERC’s regulatory oversight under the FPA, as their respective electric transmission systems are not connected to the interstate transmission grid in the continental United States.

Each ISO and RTO offers different energy products in its organised markets. While all of the existing ISOs and RTOs administer some form of bid-based markets for one or more energy products (i.e., where the highest price bid for the marginal quantity of supply that satisfies the quantity demanded in any relevant period sets the market price for the product within that applicable region, node or zone), some provide real-time and day-ahead markets, while others do not. In addition, some of the ISOs and RTOs offer forward markets for the sale of capacity (i.e., the ability to produce electric energy) separate from other energy products. Such forward capacity markets are structured differently in each RTO and ISO and the details associated with the ancillary service markets for these ISOs and RTOs differ as well.

For example, following severe weather in 2013–2014 in the eastern portion of the United States, when demand was high and generation supply was unavailable for a variety of reasons, both ISO-New England and PJM sought to improve generator reliability during these periods by proposing significant changes to their forward capacity market rules. ISO-New England’s proposed changes, referred to as ‘performance incentive’ or ‘pay for performance’ were adopted in 2014, and PJM’s proposed changes, referred to as ‘capacity performance’, were adopted in June 2015. All capacity resources that clear ISO-New England’s market became subject to pay for performance requirements beginning with the delivery year that commenced in June 2018. All capacity resources that clear the PJM market are subject to capacity performance requirements beginning with the delivery that commences in June 2020. Both programmes eliminate most of the excuses for non-performance during a delivery year and increase the penalties for non-performance, as well as the financial assurances required to be posted by proposed capacity resources.

Each market has an independent market monitor, as FERC required by Order No. 719, but the nature and scope of the market monitors’ roles differ. As a general matter, the independent market monitor within each RTO and ISO provides independent oversight over certain market issues, including with respect to market structure, conduct and performance issues. RTOs and ISOs that are interconnected to one another have special joint operating arrangements relating to the ‘seams’ between them. Moreover, CAISO has established and made available to other electric grids in the western United States that are neither RTOs nor ISOs a Western Energy Imbalance Market (Western EIM) that on a regional basis can automatically balance supply and demand and dispatch least-cost energy resources on a short-term basis. This system is intended to assist California and other states in the western United States to better manage and share their generation capacity reserves and integrate intermittent renewable generation resources. Electric grids in eight western states and British Columbia, Canada are active participants in the Western EIM and portions of the electric grid in two other western states plan to join by 2021.

Wholesale energy market rules and regulation

Each RTO and ISO develops its own market rules through the market participants’ stakeholder approval process. Market rules for all RTOs and ISOs must be filed with and approved by FERC prior to implementation, except for ERCOT, whose market rules are subject to the exclusive jurisdiction of the Public Utility Commission of Texas.
iii  Contracts for sale of electric energy at wholesale

The US electricity markets have a long history with bilateral power purchase and sale contracting at wholesale. Even where market participants are located within an applicable RTO or ISO (i.e., bidding or offering into the organised wholesale markets and scheduling flows through the RTO or ISO), market participants often enter into bilateral energy and capacity contracts as a means of hedging the volatility of market prices or providing a reliable source of supply. Bilateral contracts can be in the form of physical purchases and sales or financially settled purchases and sales. Some contracting parties use standardised industry form agreements, such as those developed by the Edison Electric Institute or the International Swap and Derivatives Association, and others negotiate individualised contracts. Physical sales of energy, capacity and ancillary services products in the wholesale markets are subject to FERC jurisdiction and associated contracts must either be filed with FERC or reported through electric quarterly reports.

iv  Natural gas and oil commodity and transportation markets

Unlike in the electricity sector, there are no formal FERC-approved organised wholesale markets for oil and natural gas.

Sales of natural gas or oil commodities may be accomplished through trading platforms, like the Intercontinental Exchange or bilateral contracts. As with purchase and sale agreements for electricity, such bilateral agreements can be in the form of physical purchases and sales or financially-settled purchases and sales. Some contracting parties use standardised industry form agreements, such as those developed by the North American Energy Standards Board, and others negotiate individualised contracts.

Interstate natural gas pipelines are required to operate secondary markets for the transportation services they offer. Under FERC’s rules, any shipper that has contracted for firm transportation service on a natural gas pipeline may release its contracted capacity to other shippers, either by publicly posting the availability of the pipeline capacity on an electronic bulletin board maintained by the pipeline and accepting offers for it, or, if certain criteria are met, in a privately negotiated, but publicly posted, transaction with prices capped at the pipeline’s tariff rate. Also, to facilitate the development of natural gas markets, FERC has liberalised some of its rules designed to prevent shippers from capitalising on a pipeline’s market power. Generally, FERC requires shippers to hold title to the natural gas they ship on interstate pipelines and prohibits shippers from buying natural gas at a receipt point and reselling the natural gas to the same company after transportation at the delivery point in a prearranged ‘buy-sell’ transaction. To allow brokers to aggregate transportation capacity and natural gas supplies, and to use transportation services more efficiently, FERC allows exceptions to its shipper-must-have-title rule under qualifying asset management arrangements. FERC also grants waivers of its shipper-must-have-title, buy-sell and capacity release rules when necessary to facilitate transfer of pipeline capacity in certain circumstances involving asset sales or corporate restructuring. It is unlawful for ‘any entity’ (not just regulated companies) to engage in a course of business or omission, or mislead, with intent to affect a FERC-jurisdictional market. Violation of FERC’s market rules exposes the actor to the potential for significant civil penalties and enforcement action by FERC.

Given the limited scope of its jurisdiction over oil pipelines under the ICA, FERC historically has refrained from involvement in crude oil marketers’ use of interstate oil pipelines – except to insure that the pipelines’ rates, terms and conditions of service for all shippers are ‘just and reasonable’. In November 2017, however, in response to a petition for
declaratory order, FERC ruled that a marketing affiliate of an oil pipeline may not use its capacity on the pipeline to engage in ‘buy-sell’ transactions in which the price differential between the points of purchase and resale is less than the pipeline’s filed rate between those two points. That ruling is currently the subject of further review by FERC in response to requests for rehearing and clarification. Also, in February 2018, certain petitioners asked FERC to develop standards of conduct for oil pipelines similar to those applicable to the transportation and marketing functions of natural gas pipelines. That request is currently pending before FERC.

v Retail energy market regulation

Retail energy markets are regulated at the state and local levels. Across much of the United States, retail consumers of electricity and natural gas buy electricity and natural gas from local utilities, many of whom remain vertically integrated, at rates and under terms and conditions set by local regulators. Beginning in the mid-1990s there was a move in some states to unbundle commodity generation or natural gas service from distribution services and allow retail consumers to purchase these commodity services from competitive retail suppliers. Between 1995 and 2002, a large number of states, including California, Texas and most of the states in the northeastern United States, introduced retail competition for electricity and natural gas, and in some instances required local utilities to divest or formally separate their electric generation, as part of industry reforms generally referred to as ‘electricity restructuring’. These restructuring efforts also included various mechanisms to provide short-term savings to retail consumers as well as mechanisms to protect consumers from market volatility in the wholesale markets and requirements that distribution utilities serve as a provider of last resort for retail consumers who cannot (or do not choose to) obtain commodity service from a competitive supplier. At the same time, in many states, distribution utilities were required to charge prices for commodity service at levels above projected market prices to create a competitive opening for other retail suppliers.

During 2000 and 2001, there was an extended period of extreme volatility in wholesale electricity and natural gas markets in the western United States, which had a severe negative impact on the financial conditions of the restructured utilities in California and ultimately compelled the state of California to become a significant buyer of last resort in the wholesale electricity markets and ended retail competition for most retail consumers in California. After the California electricity crisis, further efforts at electricity restructuring at the retail level in the United States largely came to a standstill and retail competition was suspended or rescinded in several states. As of 2018, 16 states and the District of Columbia allow for retail competition. However, regulators in one of these states, New York, took action in early 2016 to limit retail competition for the majority of residential and small commercial customers by requiring retail suppliers to serve mass-market customers under contracts that either guaranteed certain customer cost savings or guaranteed a portion of retail supply from renewable energy sources. This action to limit retail competition was vacated by a state court. In late 2016, regulators in New York initiated a proceeding to determine if retail suppliers should be completely prohibited from serving their current product offerings to mass-market customers. As of early 2019, this proceeding is still pending. Since the early 2000s, a number of states have allowed for the creation of community choice aggregation (CCA) arrangements, whereby a local entity, often an entity created by a local government, can aggregate the buying power of individual retail customers within a defined local jurisdiction to secure alternative energy supply arrangements. This alternative energy supply is delivered to participating
retail customers by the already existing electric distribution utility. The presence of CCA arrangements has increased significantly since 2014, especially in California, where utility regulators have estimated that as much as 85 per cent of retail electric load served by the state’s investor-owned utilities will participate in these arrangements by the end of 2025.

V RENEWABLE ENERGY AND CONSERVATION

i Development of renewable energy

The United States does not have a single comprehensive policy regarding the development of renewable energy. Rather, the federal government provides or has provided various targeted tax incentives and financing support programmes, while a large number of states have implemented renewable portfolio or clean energy standards and net metering, tax incentives and installation cost rebate programmes for distributed renewable generation resources.

There have been a series of unsuccessful efforts by Congress to mandate a federal renewable or clean energy standard, most notably in the comprehensive greenhouse gas (GHG) cap and trade and clean energy legislation that passed in the House of Representatives in 2009. The Environmental Protection Agency (EPA) issued regulations regarding CO2 emissions from new and existing electric generating facilities (the latter referred to as the ‘Clean Power Plan’), which would limit the rate of emissions of CO2 per megawatt-hour (MWh) of generation output. The Clean Power Plan proposes in part increased generation output from renewable energy resources, as well as avoided fossil fuel-fired generation output from end-use energy efficiency measures, as compliance mechanisms. In February 2016, the US Supreme Court issued a stay, halting implementation of the Clean Power Plan pending the resolution of legal challenges to the programme in court. The Trump administration took initial steps in 2017 to repeal the Clean Power Plan and proposed the Affordable Clean Energy Rule (referred to as the ACE Rule) in August 2018 to replace it. Final steps to unwind the Clean Power Plan are expected to require regulatory actions that in and of themselves will take a year or more and are expected to be subject to legal challenges that may not be resolved before the next presidential election in 2020.

The federal government provides or has provided various tax incentives for renewable energy, including:

- a production tax credit (PTC) (per energy generated) for wind, geothermal, biomass and some other renewable energy resources (not including solar and fuel cells) for a period of 10 years from the date the renewable energy facility is placed in service;
- an investment tax credit (ITC) (based on qualified project costs) for a wide range of renewable energy resources (including solar and fuel cells) and for combined heat and power generation; and
- special accelerated depreciation rules that provided five-year depreciation for a range of renewable energy resources placed in service from 2008 to 2012.

The PTC was first implemented under the Energy Policy Act (the EP Act) of 1992, and was extended to include projects that commence construction prior to 1 January 2020, with a phase down in the credit amount for projects commencing construction after 31 December 2016. The ITC was first implemented under the EP Act of 2005 and was most recently extended until 2022, with a gradual step down of the credits between 2019 and 2022. The American Recovery and Reinvestment Act (ARRA) allowed taxpayers eligible for the PTC to take the ITC in lieu of the PTC for projects installed in 2009 through 2013 (2009 through 2012 for
ARRA also allowed taxpayers eligible for the ITC (including those taking the ITC in lieu of the PTC) to receive a cash grant from the US Treasury Department in lieu of the ITC for projects that commenced construction by the end of 2011, although projects not yet placed in service were subject to reduced cash grants under an automatic sequestration law that took effect in early 2013, affecting expenditures by the federal government. The federal government estimates that as of July 2012 it provided approximately US$13 billion in cash grants for over 45,000 renewable energy projects, although the majority of the funding was awarded to larger wind projects.

The DOE’s Loan Programs Office (LPO) has operated various loan guarantee programmes for advanced technology and clean energy projects established under Title XVII of the EP Act of 2005 and ARRA, Sections 1703 and 1705. As of early 2019, the LPO has approved more than US$30 billion of loans and loan guarantees for more than 30 projects, and has over US$40 billion available for loans and loan guarantees. As of January 2017, the LPO has issued solicitations making available up to US$4.5 billion in loan guarantees to support innovative renewable energy and efficient energy projects. The LPO also has solicitations outstanding for advanced fossil energy projects, advanced nuclear energy projects, advanced technology vehicles manufacturing and tribal energy development projects.

More than half of all states and the District of Columbia have renewable energy portfolio standards or goals requiring retail electric utilities to deliver a certain amount of electricity from renewable or clean energy resources. These standards and goals vary greatly across the states, both in terms of their levels and target dates (generally between 10 per cent and 30 per cent by no later than 2020, though some states such as Hawaii have target levels as high as 100 per cent by 2045 and others have recently increased their targets as discussed below in Section VI) and what types of energy resources qualify (e.g., fuel cells, waste energy, combined heat and power (CHP), in-state versus out-of-state resources). Some states also have specific requirements or ‘carve-outs’ for specific energy resources such as solar or distributed generation. Many of these states also allow utilities to comply with their standards through the purchase of tradable renewable energy credits, though there are no national or regional markets for these credits in large part because of the significant differences among states’ standards.

More than 40 states and the District of Columbia have established net metering policies that allow retail electricity consumers who own or host distributed renewable generation resources (predominantly solar electric systems) to supply excess generation to their retail electricity supplier in exchange for credits against their retail electricity bills over 12-month and sometimes longer periods. Typically, generation resources eligible for net metering arrangements cannot be sized at levels greatly in excess of a retail consumer’s peak demand. In recent years, a number of states have taken steps to revisit or revise their net metering policies in response to concerns by retail electric utilities that crediting excess generation supplied back to them at their full retail rate did not accurately reflect the costs and benefits to their other retail customers of distributed solar electric systems being interconnected to their transmission and distribution systems. Notably, while regulators in California, the state in the United States with the largest market for distributed solar electric systems, in early 2016 retained most of the existing net metering tariff for new net metering customers, they also set in motion a process to redesign residential rates for electricity, through mandatory time-of-use rates for newly installed distributed solar electric systems participating in net metering programmes, that could reduce the economic attractiveness of such systems. In other examples, regulators in Hawaii closed the state’s largest electric utility’s net metering...
programme to new participants, while regulators in Nevada approved a new net metering tariff that lowered the existing retail credit and imposed higher fixed charges, including initially for existing customers, though they later restored the prior tariff for existing customers. A number of states also offer various tax incentive and rebate programmes for distributed renewable generation resources. Most notably, California provides a property tax exclusion for certain solar resources as well as installation cost rebates or performance-based payments for solar and certain other renewable resources (e.g., wind, fuel cells and CHP).

As discussed above, many of the federal tax incentive and financing support programmes have ended or will end no later than the end of 2021, though some of these programmes could be extended by Congress, as has been the case in past years, and has been proposed in various pieces of legislation. However, given current fiscal concerns and related political disagreements over the nature and role of federal financial support for clean energy, the prospects for such legislation remain unclear. At the same time, state-based renewable portfolio standards, as well as net metering, tax incentive and rebate programmes for distributed renewable generation resources appear poised to remain in place or be expanded, at least in part, for the foreseeable future. Moreover, a number of states and local governments are actively considering establishing, and since 2011 several states and one local government, most notably the state of New York, have established, public–private partnership clean-energy financing entities, commonly referred to as ‘green banks’, to support deployment of renewable energy and energy-efficiency projects.

ii  Energy efficiency and conservation

The United States has a limited set of comprehensive policies regarding promotion of energy efficiency for electric appliances and energy efficiency standards for federal buildings and properties. In addition, the federal government has various targeted grants and financing support programmes as well as tax incentives for energy efficiency investments.

A large number of states have similar types of programmes (many of which are supported in whole or in part by funds provided by the federal government) and a large number of states have energy efficiency portfolio standards, similar in concept to a renewable energy portfolio standard, that require retail electric utilities to reduce their total retail sales, peak retail sales, or both, by certain amounts by target dates. Some states combine their renewable and energy efficiency portfolio standards. A number of states have also combined their energy efficiency portfolio standards with retail utility rate ‘decoupling’ policies to allow utilities to recover of and on their fixed costs regardless of reduced retail sales resulting from energy saving efforts. Certain states have implemented or will soon implement financing support programmes for end-use energy efficiency investments, including ‘on-bill’ financing or repayment programmes that allow retail utilities or third parties to finance the full cost of end-use efficiency investments for a retail utility customer and then recover of and on these investments through special charges included on the customer’s retail utility bill. A similar type financing arrangement is possible under federally authorised property-assessed clean energy (PACE) bonding authority for local governments, which use PACE bond proceeds to finance the upfront costs of energy efficiency investments in homes and small businesses and have the loans secured by an annual assessment on the home or business property tax bill, although this programme has so far generally been limited to commercial properties because of federal home mortgage insurance policies.

FERC’s Order No. 745 was adopted in 2011 to encourage demand responsiveness through market pricing mechanisms. In Order No. 745, FERC required that the RTO- and
ISO-organised wholesale electricity markets adopt market rules that treat demand reduction (i.e., ‘negawatts’) in the same way as generation supply alternatives (i.e., megawatts (MW)) for the purpose of bidding into the markets; however, the RTOs and ISOs were still given flexibility as to how to implement these market incentives. RTOs and ISOs began proposing revisions to their market rules to FERC during 2011 to comply with Order No. 745 and FERC acted on a number of these compliance filings during 2011 and 2012. Order No. 745 was challenged before the DC Circuit on a number of grounds, including that the substance of Order No. 745 exceeds FERC’s jurisdiction under the FPA, as it seeks to regulate retail sales of electricity by requiring RTOs and ISOs to pay retail customers for not consuming electricity at retail. In a decision issued in May 2014, the DC Circuit vacated Order No. 745, holding, among other things, that FERC did not have jurisdiction to issue Order No. 745 because demand response is part of the ‘retail market’, which is exclusively within the states’ jurisdiction to regulate. In January 2016, the Supreme Court issued a decision upholding Order No. 745 and FERC’s ‘affecting’ jurisdiction under the FPA to regulate demand response transactions in the organised wholesale electricity markets. The Supreme Court held that RTOs’ and ISOs’ payments for demand response commitments directly affect wholesale rates and that in addressing demand response practices, FERC has not transgressed its jurisdictional boundary by regulating retail sales. The Supreme Court also approved a ‘common-sense construction’ of the FPA’s language, previously adopted by the DC Circuit, that FERC’s affecting jurisdiction is limited ‘to rules or practices that “directly affect the [wholesale] rate”’.

VI THE YEAR IN REVIEW

i Electricity

Numerous states this year implemented ambitious energy policies aimed at reducing carbon emissions and increasing the amount of energy generated from renewable resources and energy storage resources on the grid. Corporate offtakers also entered into a record number of power purchase agreements with clean energy resources. Both FERC and state regulators meanwhile continued to grapple with how best to accommodate advanced technologies such as battery storage and the ongoing evolution of the mix of resources that supply electric energy, capacity and ancillary services. Fossil-fuelled generators again comprised nearly all retirements in 2018 and are increasingly being replaced by renewable resources despite attempts by the executive branch of the federal government to prevent ‘baseload’ generators from retiring. NERC also demonstrated the seriousness with which it takes cybersecurity standards by issuing a record-setting penalty, and California’s largest investor-owned utility filed for bankruptcy (again).

States accelerate policies to address climate change

Since President Trump announced his intent to withdraw the United States from the Paris Agreement in 2017, states have increasingly responded with their own policies to address climate change. California passed SB 100 in 2018, which requires that 100 per cent of the electricity consumed in the state must come from carbon-free sources by 2045. In doing so, California became the first state to join Hawaii in legislating a 100 per cent clean energy target. Hawaii passed legislation in 2015 calling for 100 per cent of its electricity to come from renewable resources by 2045. Since then, New Mexico, the District of Columbia and Puerto Rico have also adopted 100 per cent clean energy targets. New York’s and
Washington’s governors have also each committed to achieving 100 per cent carbon-free electricity, by 2040 and 2045, respectively. Other states are also considering more ambitious clean energy targets. In March, Wisconsin’s governor proposed in a budget to decarbonise the state’s electricity supply by 2050, and Minnesota’s governor released his own budget calling for 100 per cent clean electricity in his state by 2050. Legislation is also currently pending in Illinois that would call for 100 per cent renewable energy by 2050. These advances are indicative of the recent trend to increase renewable portfolio standards (RPS) across the country. For example, between 2015 and 2017, Vermont increased its RPS to 75 per cent by 2032, Oregon increased its RPS to 50 per cent by 2040, and Maryland increased its RPS to 50 per cent by 2030.

States are also innovating in their regulatory policies to promote clean energy technologies beyond setting overall targets for renewable or carbon-free electricity. For example, Massachusetts passed an energy bill in August that would require a minimum percentage of electricity sales to end use customers come from clean peak resources as well as setting a 1 gigawatt (GW) target for energy storage by 2025. At least five states in total have so far adopted targets specifically for energy storage, including New York, which set a target to procure 3GW of energy storage capacity by 2030.

The NYISO and utility regulators in New York also began a process in 2017 to work with electric industry stakeholders to develop a carbon-pricing mechanism for use in the wholesale electricity markets administered by the NYISO. The NYISO issued its proposal to implement such a system in December 2018. If such a mechanism is developed, it will have to be filed with and approved by FERC before it can be implemented.

**Offshore wind solicitations**

Since Rhode Island’s 30MW Block Island Wind Farm became the first operational offshore wind farm in the United States in 2016, there has been continued interest and investment in offshore wind in various coastal states across the United States. Since 2018, several north-eastern states created or increased their commitment to offshore wind energy. For example, New Jersey Governor Phil Murphy announced in January a goal of developing 3.5GW of offshore wind generation by 2030, which was adopted by the state legislature in May. The New Jersey Board of Public Utilities subsequently voted to open a solicitation in September for 1.1GW of offshore wind generation capacity – the largest single-state offshore wind generation solicitation to date. New York also established goal of procuring 2.4GW of offshore wind generation capacity by 2030, and issued a solicitation for 800MW in November. In January of 2019, New York Governor Cuomo announced further plans to increase the state’s procurement target to 9GW by 2035. Massachusetts selected winning bidders for a solicitation for 800MW of offshore wind capacity in 2018 as well, and the US Bureau of Ocean Energy Management, which oversees offshore renewable energy development in federal waters on the Outer Continental Shelf, completed an auction that raised $405 million for leases covering 390,000 acres of federal waters off the coast of Massachusetts. Rhode Island has also continued its commitment to offshore wind power, announcing the winning bid to a 400MW solicitation in May. Connecticut agreed to purchase 200MW of offshore wind in June of 2018 and announced plans to purchase an additional 100MW in December. California, Delaware, Hawaii, Maine, Maryland, New Hampshire, North Carolina, and Virginia have all also expressed interest in offshore wind, with varying levels of development. There is even interest in offshore wind for inland waters, as there are current plans for offshore wind development in Lake Eire near Cleveland, Ohio.
The continued rise of energy storage

The deployment of energy storage resources in the United States nearly doubled in 2018, with approximately 311MW/777MWh of energy storage capacity installed. The amount of energy storage in the United States is expected to double again in 2019, and by 2024, deployments are expected to exceed 4.4GW. At least five states have now adopted specific targets for energy storage, with New York’s target of 3GW by 2030 being the most ambitious to date. Other states have included energy storage in their planning processes and competitive solicitations. For example, the California Public Utilities Commission approved Pacific Gas & Electric Company’s (PG&E) proposal in November 2018 to replace two retiring natural gas-fired generators with four battery energy storage projects, two of which would become the two largest in the world once placed in service. This landmark solicitation marked the first time a utility and its regulator sought to replace retiring power plants with battery energy storage systems.

To accommodate the increased implementation of electric storage resources, FERC issued Order No. 841 in February 2018 and thereby directed RTOs and ISOs to remove barriers to the participation of electric storage resources in the organised wholesale electricity markets by requiring the RTOs and ISOs to establish market rules that facilitate such participation and take into account the physical and operational characteristics of electric storage resources. While requests for rehearing of Order No. 841 remain pending, all six RTOs and ISOs other than ERCOT filed implementation plans with FERC in December 2018. The implementation plans garnered significant testimony from stakeholders, and in April 2019, FERC issued deficiency letters asking each of the six grid operators to provide additional detail with respect to various aspects of their proposals. The RTOs and ISOs have 30 days to respond to FERC’s letters, and FERC directed the RTOs and ISOs to implement changes by 3 December 2019.

Fossil-fuelled generator retirements

The amount of power-generating capacity retired in the United States increased significantly from 2017 to 2018, with 11.6GW retired in 2017 and 18.7GW retired in 2018. Coal-fired generators made up nearly 70 per cent of the capacity retired in 2018, with gas-fired resources accounted for another 25 per cent of 2018 retirements. The 12.9GW of coal-fired capacity retired in 2018 marks the highest level of retirements of coal-fired generators since a record of 14.8GW was set in 2015. While fossil-fuelled generation still accounted for 63.5 per cent of electricity produced by utility-scale generation facilities in the United States in 2018, these retirements follow a continuing trend. Nearly all of the utility-scale power plants in the United States that were retired from 2008 through 2017 were fossil fuel-fired. In 2007, coal-fired generation capacity in the United States totalled 313GW across 1,470 generators. In the 10 years following, 529 of those coal-fired generators, with a total capacity of 55GW, have retired. Most of the planned retirements through 2020 are also coal-fired power plants and natural gas steam turbines. Looking ahead, projections show that some 7.4GW of little used gas-fired generating capacity is expected to retire by 2026 and an additional 21.4GW of coal-fired generating capacity will retire by 2024. The majority of generation capacity additions in 2018—approximately 62 per cent—were comprised of more efficient natural-gas fired generators, while wind, solar, hydro and battery storage capacity constituted all remaining additions. No new coal-fired generation capacity was added in 2018.

In August 2017, in response to a request from the Secretary of Energy, the staff of DOE issued a study in August 2017 regarding the wholesale electricity markets and grid
reliability in which they found that the wholesale markets, especially the organised markets administered by RTOs and ISOs, are operating in a manner that may result in the premature retirement of ‘baseload’ coal-fired and nuclear generation facilities that may be needed to ensure the reliability and the resiliency of the bulk power grid. In turn, in September 2017, the Secretary of Energy acted under little-used authority under the DOE Organization Act to submit a proposed rule at FERC that directed FERC to consider requiring certain RTOs and ISOs to establish tariff mechanisms providing for the purchase of energy from generation resources and the recovery of costs and a return on equity for such resources located in an RTO/ISO with an energy and capacity market that are able to provide essential reliability resources and that have a 90-day fuel supply on-site. In the FERC proceeding to address the Secretary’s proposed rule, a large number of parties submitted comments opposing the proposed rule (including an ad hoc bipartisan group of former FERC chairs). In early January 2018, FERC, with the unanimous vote of all five of its commissioners, issued an order terminating its proceeding to address the proposed rule and initiated a new proceeding to evaluate the resilience of the bulk power grid in the footprints of the RTOs and ISOs, which remains pending.

The Trump administration has since continued to evaluate other proposals to keep certain ‘baseload’ plants in service that may otherwise face retirement. In March 2018, one company submitted an application with the Secretary of Energy to declare that an emergency exists in PJM within the meaning of FPA Section 202(c) with respect to a threat to energy security and reliability. The application seeks to direct that certain nuclear and coal-fired generation facilities in PJM (including the company’s nuclear and coal-fired generation facilities, which the company asserts are at risk of retirement) enter into contracts and all necessary arrangements with PJM, on a plant-by-plant basis, to generate, deliver, interchange and transmit electric energy, capacity and ancillary services to maintain fuel diversity and grid dependability and resiliency within the PJM region. This effort is highly controversial and is being opposed by PJM and many other market participants (including the owners of some of the nuclear and coal-fired generation facilities that are the subject of the application).

**Capacity markets and state-subsidised generation resources**

FERC has explored how states’ preferences for certain generation resources have affected capacity markets since as early as 2013 when it opened a proceeding to explore the topic. Since then, both ISO-New England and PJM have developed their own proposals to address the competitive effects of states subsidising certain resources with mixed results. In March 2018, FERC approved ISO-New England’s proposed change to its capacity market rules, referred to as the ‘Competitive Auctions with Sponsored Policy Resources’ (CASPR), which provides for a new two-stage capacity auction in which existing capacity resources that clear the first-stage auction and have resulting capacity obligations can transfer their capacity obligations to new sponsored policy resources that did not clear the first-stage auction in a second-stage substitution auction and permanently exit the capacity market. The order, however, approved the changes by a divided vote of the five FERC commissioners with two dissenting votes and a concurrence.

After failing to reach a consensus among its stakeholders, PJM submitted two options to FERC in April 2018 and requested that FERC pick one of them. The first option, the capacity repricing proposal preferred by PJM, would create a second stage of the capacity auction where bids received from subsidised resources would be repriced without the resource’s subsidy to create the resource’s competitive price. The second option, referred to as ‘MOPR-Ex’,
would have expanded PJM’s existing minimum offer price rule (MOPR) to new and existing resources that received subsidies with some exceptions. In June 2018, FERC issued an order responding not only to PJM’s proposals but also to a complaint filed by a group of power producers in 2016 that also sought an expansion of PJM’s MOPR to existing generators that were receiving state subsidies. Rather than accept either of PJM’s proposals, FERC rejected both of PJM’s proposals as inadequate with respect to addressing the competitive impacts of state-subsidised resources on its capacity market and went further by finding PJM’s existing capacity market framework to be unjust and unreasonable. FERC also found, however, that it could not make a determination as to what would be an acceptable replacement based on the record before it and instead instituted a paper hearing for parties to submit additional arguments and evidence regarding what the replacement should be. FERC did preliminarily find that modifying two aspects of the PJM capacity market ‘may’ provide for an acceptable replacement, namely expanding the MOPR to new and existing subsidised generators with few or no exceptions and also implementing a resource-specific fixed resource requirement alternative where a subsidised resource could choose to be removed from the capacity market, along with a corresponding amount of load, but continue to participate in PJM’s energy and ancillary services markets so as to accommodate state-sponsored resources without requiring load-serving entities to pay for capacity twice. Hundreds of filings have been submitted in these proceedings and as of early May 2019, FERC had yet to issue an order directing PJM how to restructure its capacity market despite its pledge to make every effort to issue an order establishing a replacement structure by 4 January 2019. PJM’s next capacity auction, which is typically run in May, has been pushed back to August, although questions remain as to whether the auction will be run at that time and if so, pursuant to what rules.

Record default in PJM financial markets

The largest default in the history of PJM’s financial markets occurred in 2018 with the default of GreenHat Energy LLC (GreenHat). Over the course of approximately three years, GreenHat obtained a portfolio of financial transmission rights (FTRs) valued at over US$150 million while providing only limited amounts of collateral given PJM’s rules that were in place at the time. An FTR functions as a hedge on transmission congestion and is used to help energy buyers, generators, and distributors protect against local price swings.

On 21 June 2018, PJM declared that GreenHat was in default after missing a weekly payment of US$1.2 million. As a result of the default, and in accordance with its operating agreement, PJM began liquidating the FTR positions on which GreenHat had defaulted in July. However, PJM quickly halted this liquidation process as it began to observe market illiquidity and large risk premiums for GreenHat’s positions, which could have resulted in significant losses for PJM’s members. PJM then began a stakeholder review process under which new procedures for liquidating GreenHat’s portfolio were developed. PJM also agreed to create a new chief risk officer position, institute training programs for risk management and conduct a general review of its FTR market.

In October 2018, PJM proposed rule changes to FERC to address future defaults and also requested that they be applied retroactively. While FERC accepted these rules going forward, FERC denied PJM’s request to apply the rules retroactively and noted that its Office of Enforcement is conducting an investigation of GreenHat’s actions. The denial of the waiver request, however would require PJM to rerun the July 2018 FTR auction. Further, PJM would be required to recalculate the default allocation assessments made to date for GreenHat’s FTRs that went to settlement during the period of September 2018 through
January 2019 if those FTRs are liquidated when the auction is rerun. PJM estimates that this process could result in a revised total default reference of at least US$430 million and result in US$250 million to US$300 million in increased total default allocation assessments to PJM members. Multiple parties sought rehearing of FERC’s order denying PJM’s waiver request, and those requests for rehearing remain pending.

**Cybersecurity**

An increased focus on cybersecurity in the energy sector has materialised after several high-profile intrusions affected multiple companies with nuclear power plants in the United States in 2017. NERC is the nation’s ERO in charge of developing and enforcing reliability standards for the bulk power grid, including Critical Infrastructure Protection (CIP) standards that address physical and cybersecurity. On 25 January 2019, NERC published a notice of penalty to an unnamed utility for a record-high total of US$10 million after citing some 127 violations of reliability and security standards between 2015 and 2018. Violations of CIP standards were the most frequently violated. NERC also published a US$2.7 million fine on 31 May 2018, for one utility that reportedly left usernames, passwords and grid information unsecured.

**Judicial review of FERC enforcement cases**

FERC has substantial civil penalty authority under the FPA, including the ability to issue civil penalties in excess of US$1 million per violation, per day in addition to requiring disgorgement of ill-gotten gains. In the event that FERC finds an entity liable, under the FPA the entity has the ability to force FERC to litigate the matter in federal district court. There has been substantial litigation regarding the scope of the district court’s review of FERC’s findings, with FERC arguing that the district court’s review should be limited to a review of FERC’s findings based on the administrative record created by FERC (i.e., akin to an appellate type of review). District courts, however, have repeatedly and unanimously ruled against FERC, holding that they are to conduct a trial de novo, governed by the Federal Rules of Civil Procedure and the Federal Rules of Evidence.

**Ongoing transformation of the public utility business model**

Several states have continued efforts to consider the restructuring or transformation of the distribution and use of electricity at the retail level, including efforts to accommodate or encourage the greater deployment of distributed energy resources – distributed generation and storage, demand response, and end-use energy efficiency. Most notably, regulators in New York have continued their efforts to implement their ‘Reforming the Energy Vision’ (REV) initiative, that calls for ‘animating markets’ at the distribution level so that retail customers and third parties (e.g., energy service companies, retail suppliers, demand-management companies) can monetise the economic values that distributed resources can provide to the overall electric system in New York. This initiative also tasks the electric distribution utilities in New York with acting as ‘distributed system platform’ providers, who together will furnish a state-wide platform that will deliver uniform market access to retail customers and distributed energy resource providers, and who will also act as an interface between customers at the distribution level and the NYISO. As part of this initiative, regulators also directed the electric distribution utilities to propose demonstration projects involving third-party market participants and demonstrating business models and customer engagement for distributed energy resources and to propose a ‘Distributed System Implementation Plan’.
In a series of proceedings, regulators in New York are considering a wide range of issues relating to the REV initiative, including changes in their ratemaking practices for the electric distribution utilities, establishment of a new benefit–cost framework for electric distribution utility expenditures on investments in distributed system platforms, procurement of and a ‘value stack’ compensation model for distributed energy resources, energy efficiency programmes, development of community distributed generation and CCA arrangements, changes in net metering programmes, a reassessment of New York’s approach for encouraging the deployment of large-scale renewable energy generation, the development of a US$5 billion ‘Clean Energy Fund’ that will in part support the New York Green Bank and a solar electric incentive programme, and the development of a ‘Clean Energy Standard’ to succeed New York’s RPS (which expired at the end of 2015) that requires that 50 per cent of the electricity consumed in New York to come from clean energy sources by 2030. Relatedly and as discussed above, New York’s governor has since committed to achieving 100 per cent carbon-free electricity in the state by 2040. Regulators have indicated that changes in their ratemaking practices for electric distribution utilities should result in utility earnings that depend on a utility’s success in creating value for its customers and achieving regulatory policy goals, such as increased deployment of distributed energy resources and reduced emissions of GHGs, and they issued an order in 2016 adopting a suite of ratemaking changes for electric distribution utilities, including providing them with the ability to earn revenues from:

- the achievement of alternatives that reduce their capital spending and provide definitive consumer benefits;
- market-facing platform activities; and
- transitional outcome-based performance measures.

**Zero emission credit programmes upheld**

Regulators in New York have also established a ‘zero emission credit’ (ZEC) compensation mechanism to subsidise the continued operation of certain existing nuclear generation facilities in New York that face competitive difficulties in the NYISO markets, concluding that the continued operation of these facilities is necessary for New York to achieve its clean energy policy goals. Legislators in Illinois established a somewhat similar ZEC compensation mechanism directed at certain existing nuclear generation facilities in Illinois that face competitive difficulties in the PJM and MISO markets. Both the New York and Illinois programmes take into consideration the revenues that existing nuclear facilities receive in the energy and capacity markets in the determination of the ZEC payment. Legislators in New Jersey have established a similar ZEC compensation mechanism for existing nuclear generation facilities in New Jersey. Both the New York and Illinois programmes were subsequently challenged in federal courts on constitutional grounds relating to federal pre-emption under the FPA and as being in violation of the dormant commerce clause and before FERC on grounds relating to the continuing lawfulness under the FPA of forward capacity market rules in the NYISO and PJM.

In 2018, the US Courts of Appeals for the Second and Seventh Circuits upheld the ZEC programmes in New York and Illinois, respectively. In *Elec. Power Supply Ass’n v. Star*, the Seventh Circuit held that the Illinois nuclear subsidy programme was not pre-empted by federal law because it does not require the subsidised generation to participate in the FERC regulated markets. While the Seventh Circuit found that the Illinois programme ‘can influence the auction price only indirectly’, the court held that ‘because states retain authority
over power generation, a state policy that affects price only by increasing the quantity of power available for sale is not preempted by federal law’. In *Coalition for Competitive Electricity v. Zibelman*, the Second Circuit noted that the plaintiffs conceded that the New York nuclear subsidy programme did ‘not expressly mandate that the plants receiving ZEC subsidies bid into the NYISO auctions’. The Second Circuit also held that any distortions to the wholesale market are ‘(at best) an incidental effect resulting from New York’s regulation of producers’. Accordingly, the Court held that the ‘Plaintiffs have failed to state a plausible claim for conflict preemption’. The Supreme Court of the United States recently issued orders denying petitions for review of the Second and Seventh Circuits’ decisions.

**Green tariffs and corporate power purchases**

‘Green tariffs’ are programmes offered by utilities, typically in states without retail choice, that allow larger commercial and industrial customers to buy both the energy from a renewable energy project and the environmental benefit from such generation (e.g., renewable energy certificates (RECs)) in a long-term, fixed price structure. These programmes help corporate entities in states without retail choice programmes to meet their sustainability goals. Since the first green tariff was proposed by NV Energy in Nevada in 2013, 23 green tariffs in 17 states have been proposed or approved, with two denied by the relevant state public utility commission. In 2018, Kansas, Kentucky, Minnesota and Virginia each adopted green tariff programmes. Green tariff programs vary in their implementation. Some programmes allow customers to choose market-based rates pegged to the wholesale price, while others let organisations engage directly with the renewable power project. Further still, some programmes use a ‘sleeved PPA’ where the utility passes a physical power purchase agreement that it has signed with a renewable energy project along to the consumer. Green tariffs are now being used in particular by a number of larger IT firms, including Apple, which purchases from NV Energy’s GreenEnergy Rider programme, and Google, which utilises Duke Energy’s green tariff.

2018 was a record year for corporate clean energy contracts with approximately 75 deals accounting for 6.53GW, up from 2.78GW in 2017. Many of these participating companies were new entrants, with some 34 companies signing their first clean energy power purchase agreements in 2018. For example, Visa committed in 2018 to 100 per cent renewable energy by the end of 2019, and Sony expanded its 100 per cent renewable goals to China and north America.

**PG&E bankruptcy**

California faced historically destructive wildfires in 2017 and 2018, with more than 8,000 wildfires burning approximately 1.8 million acres in 2018 alone. Among the most destructive of these wildfires was the Camp Fire, which destroyed nearly 14,000 residences and killed more than 80 people. Facing liability from these fires under the state’s inverse condemnation laws, which leave utilities subject to liabilities from wildfires if their equipment is involved, regardless of negligence, California’s largest investor-owned utility, PG&E, announced it would file for Chapter 11 bankruptcy on 29 January 2019. On 28 February 2019, PG&E announced it would record a US$10.5 billion charge related to third-party claims in connection to the Camp Fire in its full year and fourth quarter 2018 financial reports, as well as an additional US$1 billion pre-tax charge related to 2017 wildfires. According to the company, its total potential wildfire liabilities could exceed US$30 billion. PG&E previously entered bankruptcy in 2001 following the California energy crisis.
The PG&E bankruptcy also raises jurisdictional questions between the bankruptcy court and FERC related to the ability of PG&E as a debtor in bankruptcy to reject FERC-jurisdictional wholesale power contracts, an ability that debtors have under the federal Bankruptcy Code with regard to executory contracts. In January 2019, FERC issued a declaratory order asserting that it has concurrent jurisdiction with the bankruptcy court over the disposition of these types of contracts such that PG&E would need to obtain approval from both FERC, under its applicable standard of review, and the bankruptcy court, under its applicable standard of review, to reject such an agreement. In the bankruptcy court, PG&E has sought a preliminary injunction against FERC to prevent it from exercising its asserted concurrent jurisdiction. The injunction proceeding is ongoing and, regardless of the outcome, is expected to be appealed to the Ninth Circuit Court of Appeals following its issuance. California regulators have also asserted that the California Public Utilities Commission’s permission would be needed by PG&E to avoid contractual commitments with clean energy resources or else it would interfere with the state’s clean energy goals and have also considered splitting up the PG&E’s natural gas and electric divisions into separate companies. The bankruptcy proceeding remains pending and is expected to continue for two years or possibly longer.

ii Natural gas and fossil fuel liquids pipelines, LNG terminals and rail transportation of crude oil

As gas production in the United States has grown dramatically in recent years, the interstate pipeline industry has proposed and constructed, with the approval of FERC, large amounts of new infrastructure to serve the new production and transport the gas to markets. In 2016, for instance, FERC certificated approximately 17.6 billion cubic feet per day of new pipeline capacity. Pipeline certificate proceedings have increasingly been heavily contested, with significant opposition to many projects from certain environmentalist organisations and landowners. These organisations have challenged projects at FERC and, in many cases, appealed FERC’s rulings to the courts.

In June 2014, the DC Circuit ruled that the FERC had violated the National Environmental Policy Act of 1970 (NEPA) by improperly ‘segmenting’ its review of four proposed expansions of the pipeline system of Tennessee Gas Pipeline Company in the north-eastern United States. FERC regarded the proposed expansions as four separate projects because each resulted in a measurable increase in the pipeline’s overall capacity and therefore provided substantial independent utility. The individual proposed projects were reviewed individually by the FERC and then constructed in rapid succession between 2010 and 2013. The DC Circuit found that the projects were ‘physically, functionally, and financially connected and interdependent’ and should all have been reviewed by the FERC at the same time as ‘connected’ projects under NEPA, and that the FERC should have considered the ‘cumulative impacts’ of all four projects together before approving any one of them. The DC Circuit remanded the case, which involved one of the already built and operating segments, to FERC, but it did not vacate FERC’s order. This decision allowed the pipeline segment to continue to operate while FERC supplemented its environmental analysis. On remand, FERC conducted a supplemental environmental review and reaffirmed its approval of the challenged pipeline project. The DC Circuit’s decision is significant in three respects: (1) although challenged many times, FERC had not previously lost an appeal of a natural gas pipeline case under NEPA; (2) the decision creates uncertainty as to when proposed pipeline
projects must be reviewed together, as many proposed projects affect other proposed projects; and (3) the court allowed the pipeline to operate despite its finding that FERC had violated NEPA.

In August of 2017, the DC Circuit vacated and remanded FERC’s orders approving the Southeast Market Pipelines project for failure to evaluate the effects of downstream GHG emissions associated with non-jurisdictional power plants receiving fuel from the project, or to explain why it could not do so. FERC re-approved the project after providing a supplemental analysis, including disclosure of an upper estimate of emissions from the power plants, but without assessing those impacts using the social cost of carbon tool – with two of the five FERC Commissioners dissenting. In subsequent pipeline certificate proceedings, the extent to which FERC needs to consider GHG emissions associated with upstream production and downstream consumption of natural gas has frequently been a contested issue.

Also in 2017, a number of state regulators responsible for issuing water quality determinations under the Clean Water Act withheld or denied certifications for FERC pipeline projects, leading to litigation in a number of courts. The leading case involved a New York State water quality certification for Millennium Pipeline’s Valley Lateral pipeline. After New York State failed to act within the one-year time frame set by the statute, the project obtained a ruling from FERC finding that the state waived its certification authority under that statute. New York appealed to the Second Circuit arguing that it had one year from the date a ‘complete’ application is filed to act, while FERC countered that the one-year period begins when the application is initially filed. The Second Circuit sided with FERC. In another case involving Constitution Pipeline, the Second Circuit declined to decide a challenge to New York’s failure to issue a water quality determination, instead requiring that the pipeline first seek a waiver from FERC. FERC subsequently denied the pipeline’s waiver request because the state agency had acted within one year of receipt of the most recently filed application, after the initial application was voluntarily withdrawn and resubmitted by the pipeline.

With respect to oil pipelines, FERC has continued to allow more flexibility with respect to rates, terms and conditions of service for committed shippers on new and expanded oil pipeline capacity when that capacity is offered to all potential shippers in an open season process. Among other approvals, FERC has allowed committed shippers to negotiate rates not supported by cost of service, and to have priority to future available capacity and future expansion projects following the open season. FERC has also approved tiered rates for shippers based on the size of their volume commitments and acreage dedications. Other FERC orders, however, have defined the limits of FERC’s flexibility, including orders denying priority service to shippers that enter into contracts after (but not during) an open season, and orders refusing to pre-approve uncommitted shipper rates for new and expanded oil pipelines unless pursuant to a formal rate filing made shortly before service commences. In 2015, FERC also determined that the transportation by pipeline of denatured fuel ethanol in interstate commerce is subject to its jurisdiction.

In July 2016, the DC Circuit issued a decision that ultimately had broad implications for the interstate pipeline industry. In United Airlines v. FERC, 827 F.3d 122 (DC Cir 2016), the DC Circuit sided with pipeline shippers that challenged FERC’s income tax allowance policy. FERC’s income tax allowance policy, in place since 2005, allowed US MLPs and other pass-through entities that hold interests in regulated oil and natural gas pipelines to include in rates an income tax allowance if their partners or members have actual or potential income tax obligations on the partnership’s or other pass-through entity’s income. In United Airlines,
the DC Circuit concluded that FERC had acted arbitrarily and capriciously when it permitted the pipeline in question to include an income tax allowance in its rates, because FERC had failed to demonstrate that its income tax allowance policy together with its use of a discounted cash flow methodology to determine return on equity would not permit the pipeline's limited partnership owners to double-recover their income taxes through the pipeline's rates. The DC Circuit vacated FERC’s orders authorising the pipeline’s rates, and remanded the case to FERC for further proceedings. In its decision, the DC Circuit held that FERC is free to continue to provide partnerships and other pass-through entities with an income tax allowance if it either provides a sufficient explanation that its current policy does not result in double-recovery of taxes for such entities, or takes another approach to assure there is no double-recovery.

In response to the United Airlines decision, FERC issued a Notice of Inquiry (NOI) in December 2016 and received two rounds of comments in response to the NOI. In March 2018, FERC ruled on the issue on remand, announcing in its ruling and in a revised policy statement that FERC will no longer permit MLPs to recover an income tax allowance in cost-based rates because such recovery allows an impermissible double recovery of income taxes. Going forward, FERC announced that other pass-through entities may be allowed to recover the income tax allowance in cost-based rates, but only if they address the double recovery concern expressed in United Airlines and the revised policy statement. The same day, FERC issued orders initiating a rulemaking and another NOI to evaluate whether the recent lowering of the US corporate tax rate from 35 to 21 per cent should be reflected in individual oil and gas pipelines’ cost-based rates, or trigger other changes to rates in response to recent changes in US tax laws.

In July 2018, FERC issued a final rule (Order No. 849) that required gas pipelines to submit informational reports showing the impact of lower corporate tax rates and the disallowance of taxes for MLPs in their cost-based rates. FERC’s orders encourage gas pipelines either to reduce their rates voluntarily by initiating limited, ‘single issue’ rate proceedings, or to provide justification why their rates should not be reduced. FERC reserved the right to investigate potential over-recovery by gas pipelines that do not voluntarily reduce their rates. FERC also clarified that a pipeline organised as a pass-through entity is considered subject to federal corporate income tax (and thus may include an income tax allowance in rates) if all of its income or losses are consolidated on the federal income tax return of a corporate parent. In compliance with the rule, gas pipelines filed the informational reports. Some pipelines voluntarily reduced rates as part of negotiated settlements with customers and FERC initiated investigations into the reasonableness of certain pipeline rates after concluding that the pipelines may be substantially over-recovering their cost of service. In most cases, however, FERC elected not to take any action regarding pipelines that did not modify their rates.

Under FERC’s approach in the final rule, oil pipeline rates will be reduced through FERC’s next round of five-year indexing adjustments in 2020, to be effective 1 July 2021. In the interim, liquids pipeline shippers may file complaints if they believe the pipelines rates are unreasonable; and liquids pipelines that initiate rate changes must comply with the lower corporate income tax rates and new rule applicable to pipelines organised as flow-through entities.

Between 2013 and 2017, FERC approved the construction and operation of 10 large-scale LNG terminals, nine for the export of LNG produced from natural gas originating in the continental United States and one for the import of LNG to the Commonwealth of
Puerto Rico. Three of these projects (Cheniere’s Sabine Pass and Corpus Christie terminals and Dominion Cove Point) have completed construction and are exporting cargos from the lower 48 United States. Exports from three additional projects (Elba Island, Cameron LNG, and Freeport LNG) are expected to commence operations in 2019. In early 2019, FERC authorised its first new LNG export project in over two years, the Venture Global Calcasieu Pass Project, and then authorised two additional projects (Port Arthur and Driftwood) just a few months later.

Several FERC orders approving LNG projects were appealed to the DC Circuit by the Sierra Club and similar non-governmental environmental organisations. These appeals concerned both project-specific issues and common issues regarding FERC’s NEPA review as related to more general, ‘indirect’ and ‘cumulative’ environmental impacts. Among the common issues were claims that approval of new LNG terminals will induce additional US natural gas production for export, thereby increasing demand for natural gas and increasing its price in the US, resulting in the increased use of coal rather than natural gas to generate electricity. These groups also asserted that approval of LNG exports would contribute to increased GHG emissions from downstream end-use of natural gas. In a series of separate opinions issued by the DC Circuit during the latter half of 2016, the Court affirmed FERC’s orders approving four large-scale LNG terminals, holding that the environmental review did not have to address the alleged indirect and cumulative effects of the LNG exports in upstream and downstream markets, in part because DOE has sole authority to authorise the export of natural gas and LNG. The DC Circuit also held that FERC adequately considered the environmental effects of the LNG terminals, together with any other past, present or likely future actions in the same geographic area.

In early 2016, FERC denied the applications to construct the Jordan Cove LNG export terminal in southwest Oregon and the related Pacific Connector Pipeline. FERC found that the proponents of the Pacific Connector Pipeline had presented only general evidence as to natural gas demand in an effort to prove a need for the pipeline, but no evidence of subscriptions for its services. In the absence of more tangible evidence, FERC determined that the project was not in the public interest because the proven benefits of the project did not outweigh the detriment to approximately 630 landowners, including 54 intervenors, whose property would be disturbed by the pipeline. FERC also determined that the LNG export terminal is not feasible without the pipeline. The project’s proponents sought rehearing (essentially reconsideration) of FERC’s order, which FERC denied, and later filed a new application with supplemental support demonstrating market support for the pipeline.

In August 2014, DOE announced a change in its policy regarding the processing of export applications to streamline its process by linking the timing of its final action on an application to follow the completion of environmental reports by FERC and other agencies. DOE also issued reports supplementing the environmental analysis of LNG export terminals, including an analysis of the effect of LNG exports on GHG emissions and a new study of the estimated economic consequences of LNG exports (up to the equivalent of 20 billion cubic feet of natural gas per day or approximately 168 million tonnes per year) that found that such additional exports would be marginally beneficial to the US economy. In September 2014, DOE issued a notice of change in its procedures for changes in control affecting applications and authorisations to export or import natural gas. The new procedures allow for authorisation holders to file a notice or statement of a change in control within 30 days of such a change in control. For changes in control related to existing authorisations or pending applications for authorisations to export to non-FTA countries, DOE will consider properly submitted
protests of such changes in control but DOE will take no action unless it determines that the change in control renders the underlying authorisation at issue inconsistent with the public interest.

Under that policy, DOE has consistently authorised LNG projects, after they receive FERC authorisation for construction and operation, to export LNG to all countries not specifically prohibited from receiving LNG from the United States (i.e., countries not subject to United States trade sanctions), including countries without free trade agreements to which the United States is a party, that require national treatment for trade in natural gas (non-FTA countries). DOE issued such a non-FTA export authorisation in April 2017 that followed its prior precedent, indicating that there was no change in policy with the new administration. Later in 2017, DOE commissioned a new macroeconomic study of the effects of LNG exports. The study was issued for public comment in June 2018, and DOE responded to those comments in December 2018. Like the prior DOE studies of the issue, the 2018 study concluded that the US will experience net economic benefits from LNG exports. Relying in part on this study, DOE authorised LNG exports to non-FTA nations for the three LNG export project authorised by FERC in 2019, promptly following issuance of the FERC authorisations. Numerous other companies proposing to develop LNG export projects have applied to FERC and the DOE for similar authority and their applications are pending.

Environmental groups filed challenges to many of the DOE’s orders authorising exports of LNG (similar to those lodged against FERC’s orders) in the DC Circuit. In a series of orders issued in 2017, the DC Circuit rejected all arguments that DOE failed to adequately consider the cumulative and indirect impacts associated with induced upstream gas production and downstream GHG emissions. The DC Circuit held that DOE’s ‘environmental addendum’ and a life cycle analysis assessing currently available data (filed and noticed for public comment in each proceeding) was a sufficient assessment of the environmental effects of DOE’s orders. The effect of these appellate decisions in the LNG and Southeast Market Pipelines proceedings is to increase overall transparency associated with natural gas sector GHG emissions, but perhaps not to the extent desired by some advocates who prefer use of the social cost of carbon tool for measuring the impact of increased GHG emissions. The orders serve as precedent for future FERC and DOE actions approving natural gas facilities and exports.

In June 2018, DOE issued a final rule to provide for accelerated approval of applications for small-scale exports of natural gas, including LNG, from export facilities to non-FTA countries. The final rule provides that DOE, upon receipt of a complete export application, will grant the application if (1) the application proposes the export of no more than 51.75 billion cubic feet of natural gas per year, and (2) the proposed export qualifies for a categorical exclusion under DOE’s NEPA regulations.

Presidential permits are required for the construction and operation of facilities that cross the international borders of the United States, including facilities for the transmission or transportation of electricity, natural gas, crude oil and petroleum products between the United States and Canada or Mexico. The authority to issue Presidential permits has been delegated by the President to the Secretary of Energy for electricity, FERC for natural gas and the Secretary of State for crude oil and petroleum products. Historically, there has been little controversy about the issuance of Presidential permits, and more than 100 cross-border energy facilities were in operation as of 2015. FERC and the Secretary of Energy, acting through
DOE, have continued to receive and, after consultation with the Secretary of Defense and the Secretary of State, approve Presidential permits for natural gas and electricity facilities in the ordinary course.

At the Department of State, however, the Presidential permit process for the Keystone XL pipeline has not followed a similar pattern. The Keystone XL pipeline is intended to transport heavy crude oil and diluted bitumen produced from Western Canadian oil sands, and light crude oil produced in the Bakken shale formation (the Bakken) in the United States, to refineries in the US Midwest. Much of this oil is transported by rail today. An application for a Presidential permit for the Keystone XL pipeline was filed with the Department of State in May 2012. The application was strongly opposed by environmental groups, and the Secretary of State in the Obama administration did not issue a decision on the then-pending application. In February 2015, Congress passed a bill approving the Keystone XL project and deeming all statutory environmental requirements to have been satisfied. President Obama then vetoed the bill, and a vote to override that veto in the US Senate failed in March 2015.

In November 2015, the Secretary of State in the Obama administration denied the application for the Presidential permit for the pipeline, finding that the pipeline would only marginally benefit the US economy and energy security, but would 'significantly undermine [the United States'] ability to continue leading the world in combating climate change'. In March 2017, the State Department in the new Trump administration reversed course and granted the application for the Presidential permit, making a determination that issuance of the Presidential permit 'would serve the national interest'. The Presidential permit granted permission to 'construct, connect, operate and maintain' the pipeline facilities at the international border between the US and Canada, and therefore applies to only 1.2 miles of pipeline. This permit was soon challenged in the US District Court in Montana. In November 2018, the court ordered to halt construction of the project, stating that the Department of State had failed to give a 'hard look' at the potential effects of greenhouse gas emissions, failed to consider impacts on cultural resources, and must supplement its prior work with new and relevant information regarding the risk of oil spills. In March 2019, the Trump administration released a Presidential permit in response to this order, again authorising the construction of the pipeline. Because the new permit was issued directly from the Office of the President and not delegated through the State Department, the government argued in an April 2019 motion to dismiss that the new permit, unlike the prior permit is not subject to the review under the Administrative Procedure Act. As of the time of writing, the District Court has not ruled on this motion.

In the meantime, certain legislative initiatives have attempted to disentangle the Keystone XL pipeline from the District Court decision. In June 2018, Senator John Hoeven (R, North Dakota) introduced a bill that would move cross-border pipeline approvals from the State Department to FERC. This is similar to a July 2017 bill that passed the US House of Representatives. Both bills have since stalled in the Senate.

Aside from Keystone XL's cross-border pipeline segment, the remaining miles of the pipeline in the United States have been approved by other regulatory bodies, including state regulators in Montana, South Dakota and Nebraska. However, Nebraska's approval requires an alternate route that adds 63 miles to the pipeline. In Canada, preliminary construction work has already begun.

In January 2017, President Trump signed a presidential memorandum directing the Secretary of Commerce, in consultation with all relevant executive departments and agencies, to develop a plan under which all 'new pipelines, as well as retrofitted, repaired or expanded...
pipelines, inside the borders of the US’, use materials and equipment produced in the United States ‘to the maximum extent possible and to the extent permitted by law’. The presidential memorandum directed the Secretary of Commerce to submit such a plan within 180 days of the date of the memorandum. After issuing a request for comment in March of 2017, the Department of Commerce engaged in no further action on the issue, missing the 180-day deadline.

In response to a series of highly publicised accidents involving trains carrying crude oil produced from the Bakken Formation, including the July 2013 derailment of a 72-car train carrying Bakken crude oil that resulted in 47 fatalities and extensive property damage in Lac-Mégantic, Quebec, US federal and state regulators have taken numerous steps to improve the safety of the rail transportation of crude oil. The North Dakota Industrial Commission issued new conditioning standards in December 2014 that among other matters established operating standards for crude oil conditioning equipment and prohibited operators from blending lighter hydrocarbons into crude oil before shipment. PHMSA and the Federal Railroad Administration (FRA) have proposed or undertaken a range of additional regulatory actions aimed at increasing the safety of rail transportation of hazardous materials, including the transportation of crude oil by rail. PHMSA and the FRA issued a comprehensive final rule in May 2015 that includes more stringent construction standards for rail tank cars built after 1 October 2015. Depending on the type of tank car, existing tank cars must be replaced or retrofitted within three or five years. The final PHMSA/FRA rule also includes mandates for using advanced braking and performing routing analyses, and makes permanent the provisions of an emergency order issued by DOT in April 2015 imposing a speed limit of 40mph in ‘high-threat’ urban areas for crude oil trains containing at least one older-model tank car. The speed limit for all other crude-by-rail service will be restricted to 50mph, in line with the speed limit railroads voluntarily adopted in 2013. The final rule requires sampling and testing programmes for all unrefined petroleum-based products, including crude oil, and certifications that hazardous materials subject to the programme are packaged in accordance with the test results, but does not require oil companies to process their products to make them less volatile before shipment, as had been proposed by certain safety advocates.

PHMSA also regulates the safety of pipelines and, following several pipeline accidents, has adopted more stringent safety standards for pipelines. Under agreements with certain state agencies, PHMSA allows the state agencies to administer federal safety standards for interstate pipelines. States are permitted to adopt stricter standards for state-regulated pipelines and several have done so in recent years. Effective as of 25 October 2013, PHMSA adopted new rules increasing the maximum administrative civil penalties for violation of the pipeline safety laws and regulations after 3 January 2012 to US$2 million for a related series of violations. State agencies have imposed even greater penalties. In April 2015, the California Public Utilities Commission approved the largest penalty it has ever assessed by ordering PG&E shareholders to pay US$1.6 billion for the unsafe operation of its gas transmission system, including the pipeline rupture in San Bruno, California in 2010 that resulted in eight fatalities and extensive property damage. In July 2014, the US Attorney for the Northern District of California filed a separate criminal indictment against PG&E alleging obstruction of the National Transportation Safety Board’s investigation of the San Bruno incident and knowing and wilful violations of the Pipeline Safety Act (PSA). The PG&E case was tried in federal district court during the summer of 2016. In August 2016, the jury in the federal district court case found PG&E guilty of five felony counts of violating the PSA and one felony count of obstructing a federal investigation. In sentencing proceedings in January 2017, the
federal district court ordered the company to pay a maximum fine under the PSA of US$3 million, placed the company on probation for five years, ordered the company to complete 10,000 hours of community service (including 2,000 hours by high-level personnel), and ordered the establishment of a court-appointed monitor. Congress passed legislation in 2016 amending the PSA and reauthorising PHMSA’s pipeline safety programme through 2019. However, the legislation did not revise the standard for criminal liability under the PSA for pipeline safety violations, despite some senior DOT officials advocating a lower liability standard – from ‘knowingly and wilfully’ to ‘recklessly’.

Meanwhile, PHMSA continues to review and revise its existing pipeline safety standards. Among its most significant recent regulatory proposals are two companion rules addressing pipeline safety and integrity, one applicable to hazardous liquid pipelines (which include crude oil and natural gas liquids pipelines) and another applicable to natural gas pipelines. The October 2015 proposal governing hazardous liquid pipelines would have extended existing integrity management requirements to previously-exempt pipelines and would have imposed additional obligations on hazardous liquid pipeline operators that are already subject to existing integrity management requirements. The proposal also would have required operators to evaluate annually the protective measures they have implemented on pipeline segments that operate in ‘High Consequence Areas’ where pipeline failures have the highest potential for human or environmental damage, would have established shorter repair timelines for critical pipeline repairs, and would have tightened the standards for pressure tests. PHMSA issued a final rule in January 2017, just prior to inauguration of the newly elected US president. The final rule modified certain aspects of the proposed rule to address concerns expressed by the regulated industries during the comment period, but retained key aspects of the rule regarding expanded inspection, leak detection, and reporting requirements. The rule was withdrawn in late January 2017.

In April 2016, PHMSA published proposed revisions to its pipeline safety regulations applicable to onshore natural gas transmission and gathering pipelines. The proposed rule would significantly broaden the scope and strength of PHMSA’s safety regulations by adding new assessment and repair criteria for natural gas transmission pipelines and by extending such protocols to pipelines located in newly designated ‘Moderate Consequence Areas’ where an incident would pose a risk to human life. In addition, the proposed rule would, among other things, modify assessment and repair criteria for pipelines inside and outside High Consequence Areas, provide additional direction to pipeline operators on how to evaluate internal inspection results, expand mandatory data collection and integration requirements for integrity management, and require a systematic approach for verifying a pipeline’s maximum allowable operating pressure (MAOP) and reporting of MAOP exceedances. The April 2016 proposal would also revise the definition of gathering lines, and repeal an exemption for natural gas gathering line reporting requirements. The proposed changes regarding gathering lines in particular have received opposition from industry. In January 2017, the Gas Pipeline Advisory Committee convened a meeting to discuss the proposed revisions, which would extensively modify Part 191 and Part 192 of the federal pipeline safety regulations applicable to gas transmission and gathering pipelines. Additional meetings were held in 2017 and are expected to be held through June 2018 to discuss, among many other technical requirements, the application of the new regulations to gathering lines. The resulting rule or rules are likely to issue in mid-to-late 2018.

Responding to the high-profile leak of methane gas from the Southern California Natural Gas Company’s Aliso Canyon/Porter Ranch underground storage field in October
2015 and calls from the Obama administration to act, PHMSA issued an Advisory Bulletin in February 2016 addressing the operation of underground storage facilities used for the storage of natural gas. In the Advisory Bulletin, PHMSA recommended that all operators of underground natural gas storage facilities have processes, procedures, mitigation measures, periodic assessments and reassessments, and emergency plans in place to maintain the safety and integrity of all wells and associated storage facilities, whether those facilities are operating, idled, or plugged. PHMSA specifically instructed operators to review their operations to identify the potential for leaks and failures caused by corrosion, chemical damage, mechanical damage or other material deficiencies in piping, tubing, casing valves, and associated facilities.

On 22 June 2016, the US Congress enacted the Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016. Among other things, the act required PHMSA to issue, within two years, minimum safety standards for underground natural gas storage facilities. In addition, the PIPES Act allowed states to adopt more stringent safety standards for intrastate facilities, if such standards are compatible with the minimum standards prescribed in the Act. On October 14, a federal interagency task force convened to study the issue and released a final report and fact sheet on underground natural gas storage regulation. The task force was co-chaired by the DOE and PHMSA, and included members from numerous federal, state, and local government agencies. The report included 44 recommendations regarding well integrity, public health and environmental effects, and energy reliability. On 19 December 2016, as required by the Act, PHMSA published an interim final rule that revised existing federal pipeline safety regulations related to downhole facilities, including wells, wellbore tubing, and casing at underground natural gas storage facilities. The interim final rule also incorporated certain recommended practices of the American Petroleum Institute into PHMSA's federal safety standards, including practices applicable to the design and operation of solution-mined salt caverns used for underground storage, and practices applicable to the functional integrity of natural gas storage in depleted hydrocarbon reservoirs and aquifer reservoirs. The interim final rule also requires that operators of underground natural gas storage facilities file annual reports, obtain operator identification numbers, and file incident and safety-related reports. The interim final rule also applies to intrastate storage facilities, and requires states to update their safety regulations to include the specified recommended practices. The interim final rule became effective on 18 January 2017, and owners and operators are expected to implement the new requirements by 18 January 2018.

The state of Texas and two natural gas and pipeline industry trade associations have filed separate petitions for review of PHMSA's interim final rule, which are pending at the US Court of Appeals for the Fifth Circuit and the DC Circuit. Texas contends that the interim final rule impermissibly overrides the state's authority to regulate intrastate underground natural gas facilities, while the trade associations challenge the timeframes for implementation and certain technical aspects of the interim final rule. In 2017, the petitions and enforcement of the interim final rule was stayed while PHMSA solicited additional comments.

VII CONCLUSIONS AND OUTLOOK

Energy regulation in the United States remains complex and multilayered, and will continue to evolve for the foreseeable future. Competing economic and political interests (including effects on ratepayers and taxpayers, and state policy initiatives aimed at increased deployment of clean energy resources and decreased GHG emissions) cause conflict surrounding
jurisdictional issues, energy security, transmission system planning, cost allocation, renewable development and integration and many other issues. The variety of energy industry participants and regulators, as well as the geographical differences across the United States, can provide an opportunity for the development of innovative policies, but such heterogeneity may also lead to disjointed or overlapping regulatory obligations and may ultimately undermine the development of a uniform national energy policy.
Chapter 29

UZBEKISTAN

Maxim Dogonkin and Iroda Tokhirova

I OVERVIEW

This review provides for the overview of the power energy sector of Uzbekistan, being currently subject to a large-scale transformation. It purposefully omits a detailed description of other energy markets, for example the natural gas market, as this would require a separate in-depth analysis owing to the multiplicity of major reforms ongoing in the country.

To begin with, the installed capacity of Uzbekistan power plants exceeds 12.5GW, making Uzbekistan one of the few energy-independent countries in Eurasia. The Uzbek power sector depends heavily on the country’s gas and oil industry, as hydrocarbons (mainly, natural gas) contribute to about 97 per cent of the country’s energy balance with the remaining 3 per cent being hydropower, coal and charcoal. There are almost 40 hydropower stations in Uzbekistan, but only nine of them have an energy capacity of more than 50MW and the relevant potential is likely to be limited, as water resources are shrinking. Currently, there are no nuclear power stations within its territory of Uzbekistan. However, the commissioning of the first nuclear power station, being constructed in cooperation with Russia’s Rosatom, is scheduled for 2028–2029.

The legal and economic structure of the power industry of Uzbekistan is relatively simple. Proceeding from the assumption that the provision of electric power is a natural monopoly where the single state-owned monopolist can be the most efficient supplier, the Uzbek government has long maintained a model where the single incumbent – JSC Uzbekenergo – has been responsible for the power generation, transmission, distribution, dispatch management, and retail sales, operating through its affiliates in each region of the country. Over the past years, however, the government has become increasingly dissatisfied with the performance of the industry and currently, seeks to enhance competition within the sector. On 1 February 2019, it was announced that the energy sector would be reformed and JSC Uzbekenergo would be restructured.2

Currently, JSC Uzbekenergo is a central, vertically integrated, state-owned holding company, controlling more than 40 utility companies. Each of these utility companies performs one or more of the above functions – the power generation, long-distance transmission, distribution, dispatch management or retail sales. The company used to cooperate closely with JSC Uzbekneftegaz, which is the state-owned holding company and the sector regulator in oil and gas. The latter recently lost some of its powers, which were transferred (along with some powers of the JSC Uzbekenergo) to the Ministry of Energy.

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1 Maxim Dogonkin is a senior associate and Iroda Tokhirova is an associate at Kosta Legal Law Firm.
The Presidential Decree providing for the unbundling, privatisation and attraction of foreign investment to the power industry was signed on 27 March 2019. According to this, JSC Uzbekenergo will cease to exist and three recently established joint-stock companies will completely replace the holding company, as explained below.

Current policy priorities in the sector include:

\[a\] maximising energy savings through rehabilitation and modernisation of existing power energy facilities and the introduction of energy-efficient technologies and equipment in various sectors of the economy to reduce costs and improve competitiveness;

\[b\] commercialising utility operations to improve performance. The government plans to continue de-monopolisation and deregulation of the power sector to increase competition. It prioritises the provision of open access to power transmission lines for power-generation companies.

\[c\] attracting private-sector investments to satisfy increased investment needs and to address the problem of depreciation;

\[d\] reducing the dependence on natural gas. The government is striving to increase the share of other energy sources by converting a number of gas-fired thermal plants to coal-fired, constructing new coal-fired power plants and increasing the share of renewable energy; and

\[e\] reducing the environmental impact of the power industry by relying on renewable energy.

II REGULATION

i The regulators

Institutional framework

The regulatory functions used to be entrusted to JSC Uzbekenergo are now in the hands of several state regulators. Since a substantial share of the Uzbekistan’s power production is dependent on natural gas, recently the government has brought the majority of relevant powers in power energy and oil and gas under sole management of the Ministry of Energy. The Ministry was established on 1 February 2019 and is responsible for, among other things, the preparation and implementation of energy policies, plans and programmes in the above industries in coordination with its affiliated institutions: Uzenergoinspektsiya, Uzneftegasinspektsiya, the Agency for Development of the Nuclear Industry (UzAtom) and the Non-Commercial Organisation for Implementation of Production Share Agreements.

Some of the Ministry’s other functions, as provided by relevant laws, include the regulation and supervision of the functioning of the power energy, gas, nuclear and renewable energy industries, the monitoring of the energy consumption efficiency, and implementation of projects under production share agreements. The above-mentioned Uzenergoinspektsiya and Uzneftegasinspektsiya control compliance with relevant state standards in the power energy and gas industries respectively:

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The main regulators also include the Ministry of Finance, exercising price regulation and general control over financial flows within the state controlled sector, and the Cabinet of Ministers, approving the Rules for the Electricity Use (REU) and the Rules for the Gas Use as well as monitoring investment programmes in the industry.

Additionally, the Uzbek Agency for Standardization, Metrology and Certification controls compliance with power energy efficiency and energy quality standards, whereas the State Antimonopoly Committee oversees how natural monopolies adhere to market rules and regulations, including the rules for price setting.

**Legal framework**

The main legislative acts for the industry are the Law on Electricity\(^5\) and the Law on Efficient Use of Power Energy,\(^6\) which determine the main state policies and the structure of the sector as well as set rules and restrictions for the country’s energy markets. The Law on Natural Monopolies\(^7\) provides for some relevant rules for companies in the industry, empowering the Antimonopoly Committee to monitor and to punish anticompetitive activities of natural monopolies and to ensure a balance between interests of consumers, the state and energy companies.

The Regulations on Provision of Energy Services\(^8\) determine the rules for the provision of services related to ensuring energy efficiency by the state-owned monopolist the National Energy Saving Company under energy services contracts that have to be entered into by state agencies and state-owned enterprises. The Rules for Using Power Energy and the Rules for Using Natural Gas\(^9\) set the rules regulating relations between utility providers and purchaser of power energy and natural gas respectively. According to the Rules, standard form contracts must be applied across these sectors, as developed jointly by JSC Uzbekenergo, the Antimonopoly Committee and controlling agencies Uzenergoinspektsiya and Uzneftegasinspektsiya, mentioned above. Some basic rules for contacts on power supply are also set in Articles 468–478 of the Civil Code.

The legal framework for renewable energy remains underdeveloped and is partially covered only in subordinate legislative acts (some Presidential Decrees and Resolutions of the Cabinet of Ministers), which mainly relate to the provision of particular tax incentives to companies operating in the sector. A draft of the fully fledged Law on Renewable Energy Sources was passed by the Uzbek parliament on 3 May 2019, and is now awaiting approval by the President. Among other things, it regulates measures for the state support and development of renewable energy and creates a legal basis for state control over the sector. In August 2018, the parliament was preparing to review the draft on the second reading,\(^10\) but there has not been any further information in this regard.

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ii Regulated activities
In general, generation, transmission, local supply, operation and retail sales in the power industry do not require special licences. In practice, however, the access to the markets is in many ways blocked. Hence, the transmission may only be performed by state-owned enterprises, which are also entrusted with centralised dispatch management, whereas local distribution networks are effectively in the hands of the state. Both categories of state-owned entities used to be controlled by JSC Uzbekenergo, but now is to be divided between JSC National Power Grids of Uzbekistan (the long-distance transmission) and JSC Regional Power Grids (the local distribution). Although private entities are able to engage in the generation of power energy, their access to the Single Power Grid (Uzbekistan's country-wide grid) requires the obtainment of a special permit. The rules for obtaining such a permit are, however, obscure and in practice, it may be impossible to get one unless an agreement is reached with the sector regulator (previously JSC Uzbekenergo and now the Ministry of Energy). Note that if legal entities and individuals produce power energy for their own use, they may trade in it but only using their own grid, since they are not allowed to connect to the Single Grid.

Recently, nevertheless, several regulations have been revealed for public discussion, setting some clearer rules for private generators, including the rules for access to the Single Power Grid. It is, however, hard to predict an exact time when these regulations will be adopted.

Speaking of retail sales, state-owned enterprises may provide private entities with the right to accept payments for electricity from consumers (i.e., act as intermediaries).

The construction of power plants and transmission lines is not licensed, special permits for each particular project may be required as, under Uzbek law, these are 'potentially dangerous [for employees, the society and the natural environment] industrial objects'.

iii Ownership and market access restrictions
As noted above, all facilities in the industry are now owned by the state. The Law on Electricity of 2009 laid the foundation for the legal unbundling in the industry, but privatisation was not pursued. Nevertheless, the above-mentioned structural ownership unbundling that will end in the liquidation of JSC Uzbekenergo and the establishment of three power energy companies are expected to preface massive privatisation. It seems that the priority in this regard will be given to foreign investors with solid experience in the power industry.

Currently, Uzbek law does not preclude foreigners from acquiring stakes in national energy companies.

iv Transfers of control and assignments
State shares in JSC Uzbekenergo are managed by the State Agency for Property Management (the Agency). As for the company's subsidiaries and affiliates, they may be owned by just JSC Uzbekenergo or both the company and the Agency (i.e., dual control is exercised in some cases).

Pursuant to Uzbek law, state shares be may transferred to private parties for performing management functions based on special standard form contracts. Such management is usually closely supervised by the Agency. To our knowledge, no such contracts in the power industry have been concluded.

Privatisation processes are governed by separate rules. State property is generally privatised through holding open auctions and tenders. The starting price varies and may be set as a fixed sum, as some fixed sum and the commitment of a potential owner to invest
a particular amount into developing the object, or as the commitment to invest only. To commence privatisation, a privatisation programme must be approved by the President and the Cabinet of Ministers. Usually direct negotiations between potential private (whether local or foreign) investors and relevant sectoral regulators (in the case of the power industry, this would be the Ministry of Energy) precede all privatisation deals.

III TRANSMISSION/TRANSPORTATION & DISTRIBUTION SERVICES

i Vertical integration and unbundling
As noted above, JSC Uzbekenergo has been a single, vertically integrated monopolist engaged in all types of activities in the power industry. The majority of Uzbekistan’s power generation, transmission and distribution assets are owned and operated by subsidiaries of this state-owned company. Generally, all major generating companies represent separate legal entities owned by JSC Uzbekenergo. Its other subsidiary, Energosotish, acts as the single buyer of power energy from generating companies and the single wholesaler to local distributors. Uzelectroset, controlling seven high-voltage operators, acts as the main dispatch manager and transmitter of power energy based on contracts with Energosotish. Local distributors also acting as retailers are represented by 14 territorial joint-stock companies owned by JSC Uzbekenergo. Based on the changes of 27 March 2019, the JSC National Electricity Grids of Uzbekistan will replace both Energostish and Uzelectroset, taking over as the single intermediary between generating companies, the majority of which will come under the control of JSC Thermal Power Plants, and local distributors, which will be controlled by JSC Regional Power Grids.

ii Transmission and transportation, and distribution access
As explained above, access to the single power grid to producers and consumers is provided based on special permits granted by subsidiaries of JSC Uzbekenergo based on relevant state rules and standards, and has to be financed and organised by those requesting access. As almost no private grids exist, there is no alternative to this procedure and for all major endeavours a pre-agreement with JSC Uzbekenergo or its subsidiary or affiliate is recommended.

iii Rates
The Ministry of Finance is the state body responsible for setting tariffs in the power industry. In doing so it acts based on the Regulations on Tariff Groups of Consumers of Electrical and Heat Energy,11 which establishes three types of tariffs and 10 groups of consumers, thus setting basic principles for defining tariffs.

The three types of tariffs applied are:

a single-rate tariffs – usually the fee per 1kW/h of active power energy supplied to customers;

b double-rate tariffs – the annual payment for 1kW of the maximum power capacity declared for consumption by customers and the fee for 1kW/h of supplied electricity; and

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differential (time-of-use) tariffs – local distributors have the right to differentiate power energy tariffs based on the time of day (peak hours, half-peak hours or night load) and seasons (summer and winter periods), provided that customers have multi-tariff metering devices.

Ten of the above consumer tariff groups include industrial enterprises with a connected capacity of up to 750kW, industrial enterprises with a relevant capacity of more than 750kW, budget organisations, consumers using electricity for domestic needs, consumers using electricity for heating and others.

Some discounts are provided to socially vulnerable consumers, based on relevant decrees of the President. Such discounts are secured by the state subsidising local distributors, selling electricity at a discount.

Generally, based on some assessment by external experts, tariffs set by the Ministry remain significantly below the market level and are not able to satisfy ever-growing demands for investment.

iv Security and technology restrictions

Operators of power grids have the obligation to inspect and to maintain power grids; to reconstruct, transform or stop using power grids in a timely manner if they do not satisfy the safe-use requirements; to put up, repair or change signs related to power grids; and to take effective safety measures for power grids not in operation.

Other obligations for operators are in place under the Law on Electricity. Hence, power grids must be operated based on the principles of safety, high quality and economy. Power grids must be maintained so that the power supply remains uninterrupted and stable. Pursuant to the Law on Efficient Use of Energy, energy producing and consuming facilities along with the energy itself are subject to standardisation and certification. Further, the Law on the Protection of Nature,12 the Law on Ecological Control13 and the Law on the Protection of the Atmosphere14 impose the obligation on entities in the energy sector to take pre-emptive measures to decrease levels of potential environmental impact.

At the moment, concerns about cybersecurity and data processing have not come to the forefront with respect to the power industry. Some basic things are only partially addressed in bilateral and international treaties to which the country is a party, including the Shanghai Cooperation Organisation’s agreement on cooperation in the field of ensuring international information security and the India–Uzbekistan agreements on the development of cooperation.

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IV ENERGY MARKETS

i Contracts for sale of energy

Currently, relevant contracts for the supply of power energy may only be concluded between state-owned distributors and consumers, albeit private entities have the right to act as intermediaries in accepting payments under such contracts. As noted above, standard form contracts are used, as developed by JSC Uzbekenergo and the aforementioned state agencies. To become a valid consumer of energy, a particular consumer has to meet certain criteria (e.g., it must have the equipment necessary for the connection to territorial power grids and have metering devices installed). Prices under the contract are non-negotiable and are subject to state regulation.

The Rules for Using Power Energy, cited above, contain a number of provisions that have to be reflected in standard contracts. Thus, legal entities are allowed to purchase energy only after making the 100 per cent advance payment. Power supply contracts with legal entities also have to contain a provision on the payment of penalties to local power distributors in the amount of 50 per cent of the respective tariff for the amount of energy consumed in the relevant billing period in excess of the fixed amount set in the power supply contracts for more than 5 per cent. Likewise, if at the end of the billing period, the actual power load for a consumer exceeds the amount set in the power supply contract by more than 5 per cent, recalculation has to be made with respect to the load and the additional charge of 50 per cent of the tariff for the period may be imposed.

There are no separate rules that may potentially govern the supply of power energy by private generating companies. As for now, general rules for such contracts as provided by Articles 468–478 of the Civil Code will apply. It is highly likely, however, that a separate set of regulations will be developed.

ii Market developments

Apart from the unbundling and the privatisation reforms mentioned above, some other changes will have an impact on Uzbekistan’s power energy market.

Currently, as briefly noted above, Uzbekistan has no nuclear power stations. However, despite some previous reluctance to use nuclear energy, the Uzbek government has adopted the Concept for Development of Nuclear Energy for 2019–2029, envisaging the construction of a nuclear power station with the total capacity of 2.4GW. Russia’s Rosatom is going to be engaged to lead the project.

Under the total restructuring of the power industry projected by the reforms of 27 March 2019, a modern multidisciplinary project organisation, JSC UzEnergoEngineering, will be established. Among other things, it will engage in the design of power grids with a voltage of 0.4–500kV with the use of innovative technologies and the latest experience in the field.

Some other significant legal changes that are likely to seriously affect the market include: the provision of access to the single power grid to independent (private) producers of energy; incentives aimed at increasing the market share of generators using renewable energy; and changes in the tariff system with more market indicators being taken into account.

V RENEWABLE ENERGY AND CONSERVATION

ii Development of renewable energy

Currently, the renewable energy sector is almost non-existent in Uzbekistan (not taking into account hydropower stations), as renewable sources are not used on an industrial scale. In 2009, Uzbekistan signed the Statute of the International Renewable Energy Agency (IRENA) and became a member of IRENA as a result. Nevertheless, the development of the renewable energy industry has not accelerated until recently.

Some basics of Uzbekistan’s policy on renewable energy, as mentioned above, are set forth in several presidential decrees and the Law on the Efficient Use of Energy. As noted, the draft Law on Renewable Sources of Energy is expected to be approved soon.

In 2017–2018, owing to environmental concerns and resource depletion (particularly of natural gas), the government focused its attention on renewable energy again, and since then several attempts have been made to improve the legal framework for the industry. The lack of single institutional and legal frameworks seems to be the main contributor to the poor performance of the sector.

Therefore, on 26 May 2017, the President approved the state programme on developing renewable energy and boosting energy efficiency for 2017–2021. Its priorities include fostering the use of renewable sources, switching away from fossil fuels and ensuring the universal installation of energy-efficient technologies. Solar energy is expected to become the key source for the development of the energy sector by 2030 followed by hydro and wind power. Tax incentives are intended to be provided to projects in the field.

As regards hydropower, in May 2017 most of JSC Uzbekenergo hydropower generation assets were transferred to the newly established joint-stock company Uzbekhydroenergo. On 2 May 2017, the Programme of Measures for Further Development of the Hydropower Sector for 2017–2021 was adopted, addressing approved projects for the construction of new hydroelectric power plants and the modernisation of existing ones and the provision of tax incentives for the period up to 1 January 2022 with respect to imported equipment that is required for the above construction and modernisation projects. As mentioned above, in comparison with the wind and solar energy generation, the hydropower industry is relatively well-developed in Uzbekistan.

iii Energy efficiency and conservation

The Uzbekistan’s policy on energy efficiency is covered by the Law on the Efficient Use of Energy. The Law focuses on conservation of energy resources and their rational use. To achieve these goals, the Law provides for some mandatory obligations for users, producers and distributors of power energy. Thus, for example, energy-producing and consuming facilities together with energy itself are subject to standardisation and certification.

For the purpose of the rational use of energy, the government provides businesses and individuals with the following benefits:

a customs duties and taxes on the import of special equipment, tools and materials, the use of which significantly increases the efficiency of energy use;

b preferential loans for implementing national, sectoral and regional targeted programmes and projects in the field of rational use of energy;

c financial grants for intersectoral research and development activities, the implementation of pilot projects on the production of energy efficient equipment; and

d feed-in tariffs for energy for legal and natural persons that ensure the reduction of energy consumption based on set standards or manufacture competitive products while maintaining energy consumption levels, which are below some set thresholds.

iv Technological developments

As noted above, renewable energy is still a developing sector in Uzbekistan. Although Uzbekistan seems to have remarkable potential in terms of expanding its use of renewable energy resources, particularly solar energy, currently there are only few legal acts encouraging technological developments in the sector, as discussed above.

In terms of energy efficiency, the government has expressed its interest in implementing smart-grid projects that would enable the remote monitoring and control over electric meters and energy consumption.

To give an example of some development initiatives, the Resolution of the Cabinet of Ministers No. 633 of 8 August 2018 shows that the government is interested in attracting private investors into the design, financing, construction and operation of photovoltaic energy production facilities in Uzbekistan for a projected amount of US$1 billion based on public-private partnership mechanisms. One of the projects related to the Resolution is the construction of a solar photovoltaic power plant with an energy capacity of about 100MW in the Samarkand region of Uzbekistan.

Further, the government is developing the Intelligent Electricity Metering project in cooperation with Korean KT Corporation, and plans to install smart electricity metering devices in most regions of Uzbekistan. These works are expected to be completed by 2021.

VI THE YEAR IN REVIEW

Some of the key developments of 2018 and 2019, which were partially described above, are covered in the following legal acts:

a Presidential Decree No. PP – 4142 of 1 February 2019 providing for the establishment of the Ministry of Energy;

b Presidential Decree No. PP – 4249 of 27 March 2019 and Presidential Decree No. PP – 3107 of 30 June 2017: structural transformations and the unbundling in energy and oil and gas;

c Resolution of the Cabinet of Ministers No. 685 of 25 August 2018 and Presidential Decree No. PP – 4249 of 27 March 2019: measures to attract private direct investments, including foreign ones, in the energy sector by selling shares of respective joint-stock companies;

: Resolution of the Cabinet of Ministers No. 444 of 12 June 2018: the introduction of simplified procedures for obtaining licences in the oil and gas sector. Under the Resolution, the Ministry of Energy has accumulated regulatory powers that had been previously distributed among several state regulators;

18 Resolution of the Cabinet of Ministers No. 633 of 8 August 2018: http://lex.uz/ru/docs/3860084.
VII CONCLUSIONS & OUTLOOK

As the current energy policy of the Uzbek government demonstrates, Uzbekistan will focus on diversifying its energy resources, developing the renewable energy sector and attracting private investments with foreign companies.

Speaking of the legislation in the area, we expect that the draft Law on Renewable Energy Sources will soon be approved by the President. Given active ongoing development of the legislation on public private partnership and privatisation trends in the industry, it is likely that the energy sector will also be affected by the adoption of new regulations for private players, which will clarify rules for private generators and other interested businesses (e.g., by streamlining the rules for the access to the single power grid). It is also highly likely that the government will come up with some new incentives for private investors.

Overall, Uzbekistan’s energy strategy and targets for 2030 can be summarised as follows:

a proceeding with the unbundling and the de-statisation in the industry, including the reforming of the tariff-setting;

b furthering privatisation in the energy sector by attracting private foreign and local direct investment, and simplifying the rules for access to the industry for private players;

c repairing and reconstructing depreciated energy facilities with the support of private direct investments;

d extending the use of smart grids and energy-efficient technologies;

e increasing the share of renewable energy sources and in particular supporting the construction of solar energy stations; and

f commissioning a nuclear power station;
MAXIM DOGONKIN

*Kosta Legal Law Firm*

Mr Maxim Dogonkin specialises in competition law and regulatory compliance, with a particular focus on the oil and gas, power energy, infrastructure and pharmaceutical sectors. Maxim advises on competition and merger control issues in the context of a broad range of M&A transactions, joint ventures, financial agreements and regulatory investigations. Maxim is a member of the UEA Centre of Competition Policy (Norwich, United Kingdom), has been recognised as a ‘next generation lawyer in Uzbekistan’ by the international ranking agency *The Legal 500* throughout 2017–2019, is a contributor to the World Bank’s Doing Business evaluation of Uzbek business law and the author of several articles on Uzbek competition legislation.

IRODA TOKHIROVA

*Kosta Legal Law Firm*

Ms Iroda Tokhirova is a firm’s associate in the energy and PPP practices. Having graduated from the Westminster International University in Tashkent, she has been assisting firm’s lawyers in several major projects in power energy, oil and gas, healthcare and metallurgy in matters of corporate law, joint-venture agreements, financial arrangements. She is fluent in English, Russian and Uzbek and has solid knowledge in many areas of law.
ABOUT THE AUTHORS

MASOOD AFRIDI
Afridi & Angell
Masood Afridi is a partner at Afridi & Angell specialising in the areas of infrastructure and project finance, corporate and commercial, and energy law.

After working as an associate at the New York offices of the law firm of Sidley & Austin, he joined the Dubai office of Afridi & Angell in 1993. For several years, he has been a frontrunner in Pakistan’s energy sector, and has participated in the development of numerous thermal and hydroelectric power projects in the country. He has also been nominated from time to time to resolve other global issues with the power purchaser on behalf of the industry.

Acting in the capacity of project developer’s lead counsel, Mr Afridi has concluded transactions with a cumulative value of over US$4 billion, spread over several project finance transactions.

Mr Afridi has an LLM in international business and trade law from Fordham University (1990) and an LLB from the University of Bristol. At Fordham University, Mr Afridi received the Edward J Hawke Prize for graduating with the highest grade point average in his class.

ADITE ALOKE
Afridi & Angell
Adite Aloke is a senior associate at Afridi & Angell. Her practice focuses on energy and infrastructure and project finance. She has extensive experience in advising on the development of renewable energy projects in India as well as on public-private partnerships. Ms Aloke was an associate with a leading law firm in India prior to joining Afridi & Angell in 2013. She spent two years at Afridi & Angell then rejoined the firm in 2016 after working with another leading law firm in India. Ms Aloke holds an LLB from Amity Law School, Guru Gobind Singh Indraprastha University, in India (2009). Adite is dual-qualified in India and England.

ANNETTE BÁRCENAS OLIVARDÍA
Alfaro Ferrer & Ramírez
Annette is a partner at Alfaro Ferrer & Ramírez, where she began her career in 1990. She has been advising clients in the electricity sector industry for 20 years. Her work in this field dates back to 1998, when the restructuring of the state-owned, vertically integrated utility that used to provide most services in Panama began. Annette also has extensive experience in advising clients – both public and private sector entities – in matters relating to other public
services (telecommunications, energy, water, natural gas and public transportation); and in matters of public procurement in a wide variety of projects and transactions, including many key service and infrastructure projects. Mrs Bárcenas has been a professor at Santa María La Antigua Catholic University (USMA) and the Latin University of Panama where she has taught classes relating to public services. She is a member of the Panama Bar Association and the American Bar Association, and is fluent in Spanish and English.

DMITRY BOGDANOV

CMS Russia

Dmitry Bogdanov is a senior associate in the infrastructure, projects and construction team of CMS Russia. His practice focuses on real estate, construction, contract and corporate law.

Dmitry acts on behalf of foreign companies and regularly advises them, particularly in the areas of EPC projects, Greenfield and Brownfield development projects in various regions of Russia. He is also involved in due diligence as well as in drafting and negotiating agreements, including land plot leases, sale and purchase agreements and construction contracts.

Dmitry holds a law degree from the Moscow State University (MGU). He is a native Russian speaker and is fluent in English and German.

TYLER BROWN

Latham & Watkins LLP

Latham senior associate Tyler Brown works primarily on regulatory and transactional matters involving electric generation, interconnection, transmission and distribution, energy storage, and natural gas and oil transportation issues. Mr Brown’s practice focuses on wholesale electric power market design, including regional transmission development and cost allocation issues.

SALEM CHALABI

Stephenson Harwood Middle East LLP

Salem Chalabi, an Iraqi national and a lawyer, has been a corporate and projects partner at Stephenson Harwood LLP since June 2014.

Mr Chalabi is a graduate of Yale University (BA), Columbia University (MA) and the Northwestern University School of Law (JD). He has practised law with international law firms Morgan Lewis (in New York), Clifford Chance (in London) and DLA Piper (in Dubai). He is also a member of the New York Bar.

In 2003, Mr Chalabi was a deputy member of the Interim Governing Council of Iraq, and a member of the finance and legal committees. In these roles, he was responsible for drafting a large number of orders and laws, in conjunction with the Coalition Provisional Authority. In addition, in 2004, he was one of two Iraqis who drafted the Transitional Administrative Law (the Interim Constitution), which was the basis of the permanent constitution adopted in 2005.

Mr Chalabi represents various Iraqi government ministries, including the Ministry of Finance, Electricity and Oil. In this capacity, he has been very closely involved in various developments relating to the government. Mr Chalabi also advises international oil companies in Iraq, as well oil services companies.
In 2018, Mr Chalabi led a team that was given the award for the best banking and finance team in the Middle East at the Middle East Legal Awards.

ANDREINA DEGLI ESPOSTI

Studio Legale Villata, Degli Esposito e Associati

Born in Bologna in June 1960, Andreina Degli Esposti graduated *magna cum laude* in law from the University of Bologna in February 1984 and was admitted to the Bar in 1986. In the course of her academic career, she also studied at the University of Münster.

She has been involved in research and lecturing in the department of constitutional law at the University of Bologna and the departments of administrative law at the universities of Milan and Pavia, publishing various essays and contributing to entries in legal encyclopaedias.

Throughout the course of her practice – which covers both judicial (predominantly before the regional administrative courts and the State Council) and extrajudicial (providing advice in the administrative areas of M&A and joint ventures and stipulating agreements with public administrations) work – she has gained expertise in the sectors of energy, public procurement (also concerning the German legal system), environment, telecommunications and town planning, including the drafting of general planning regulations. She also has extensive experience as member of arbitration panels.

*Chambers Europe* and *The Legal 500* place her among the most prominent Italian lawyers in the field of public law.

CEDRIC DEGREEF

Stibbe

Cedric Degreef, a senior associate at Stibbe, concentrates on energy and climate law, natural resources and other commodities. He is versed in commercial contracts and regulatory advice. He has relevant expertise with regard to onshore and offshore renewable energy projects, energy efficiency projects, grid operation and construction, pipelines, mining, nuclear energy, energy commodity trading, CO₂ emission trading and the EU ETS.

GBOLAHAN ELIAS

G Elias & Co

Professor Gbolahan Elias is the presiding partner of G Elias & Co, one of Nigeria’s leading business law firms. He is also a visiting professor of law at Babcock University, Ilishan where he teaches shipping, petroleum and arbitration law. He has published widely on a range of both historical and topical legal matters and served on numerous law reform committees, university administration boards and law journal editorial boards.

He read law at Magdalen and Merton Colleges, Oxford. He has DPhil, BCL (first-class honours), MA and BA (first-class honours) degrees from the University of Oxford. He was called to the New York Bar in 1990. Professor Elias was an associate at the Cravath firm in New York and has been a senior advocate of Nigeria since 2005. He is a member of the Chartered Institute of Arbitrators.

He has advised on numerous transactions in the Nigerian energy sector, including the largest acquisitions to date of electricity generation and distribution companies. He also advised on the development and negotiation of the precedent-setting power-purchase contracts and vesting contracts for the federal government-backed single buyer of grid
electric power. He recently advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables. He is currently advising the Transmission Company of Nigeria on the Eligible Customer Regulation 2017. Professor Elias has in the last two years advised on at least six renewable energy projects.

EUGENE R ELROD
Latham & Watkins LLP

Latham partner Gene Elrod has more than 35 years of experience representing companies across the oil and gas industry – including producers, pipelines, storage and local distribution companies – and large commercial end-users of natural gas. He is ranked among the nation’s leading energy regulatory and litigation lawyers by Chambers Global, Chambers USA, The Legal 500 United States, The Best Lawyers in America and Who’s Who Legal. He was named Best Lawyers’ ‘Lawyer of the Year’ in Washington, DC for energy regulatory (2018), energy (2015) and oil and gas (2014 and 2019) and an ‘Energy and Environmental Trailblazer’ by The National Law Journal (2015).

FABRICE FAGES
Latham & Watkins AARPI

Fabrice Fages is a partner with a focus on litigation and arbitration, and he is chair of the Paris litigation department. He has also developed strong experience in regulatory and public policy, notably in regulated sectors such as the energy sector. Prior to joining Latham & Watkins, Mr Fages worked for the French Senate and the French National Assembly on various law drafts. He is a regular speaker at professional conferences on energy matters. Mr Fages is also a lecturer at the Pantheon-Sorbonne University (Paris 1), the Centrale Supelec School of Paris and the Cairo University, Egypt.

DANIEL FAJARDO VILLADA
Holland & Knight

Daniel Fajardo Villada is an associate in Holland & Knight’s Bogota office. He practises in the areas of energy and corporate law assisting local and foreign companies in a wide variety of contractual, regulatory and corporate matters, as well as both domestic and transnational mergers and acquisitions transactions. Mr Fajardo Villada primarily represents energy, oil and gas, and mining companies, as well as other types of corporations. He advises clients in contracting, due diligence, and mergers and acquisitions matters, and also has experience of both litigation and arbitration. He served as assistant professor of general regime of obligations at the Universidad del Rosario, and as an intern at the International Court of Arbitration at the International Chamber of Commerce (Paris, France).

LIDO FONTANA
Covington & Burling (Pty) Ltd

Lido Fontana is of counsel in Covington’s Johannesburg office. He has significant experience in international oil and gas, mining and power, including renewable energy, and large infrastructure development transactions, including public–private partnerships and the United Kingdom’s private finance initiative.
MICHAEL J GERGEN
Latham & Watkins LLP

Latham partner Michael Gergen has extensive experience developing practical applications of economics, finance and regulatory law to assist clients in the electric, natural gas and other network industries to compete successfully in an environment of market-based, open-access competition. Mr Gergen is recognised as a leading energy lawyer by Chambers USA and by The Best Lawyers in America. Mr Gergen is an adjunct professor of law at the New York University School of Law.

NATASHA GIANVECCHIO
Latham & Watkins LLP

Latham partner Natasha Gianvecchio focuses her practice on the regulatory and regional energy market developments that impact clients in the electric and natural gas industries. Her representations involve a broad range of issues under various federal and state energy statutes and regulations and regional energy market rules affecting the domestic energy industry. Ms Gianvecchio is consistently recognised as a leading energy lawyer by Chambers USA, is consistently recommended by The Legal 500 United States and was highlighted by the publication as a ‘next generation lawyer’ for her energy regulatory work, and, in 2015, was named by Law360 as a ‘top energy attorney under 40’ and a ‘Rising Star’.

ANDREAS GUNST
DLA Piper International

Andreas Gunst is an energy, projects and finance practitioner qualified in England and Wales, and is a partner at DLA Piper based out of both the London and Vienna offices. His practice areas cover the entire energy value chain, including upstream oil and gas exploration, production, transportation and trading (both OTC and exchange); electricity generation projects from conventional and renewable energy sources; electricity transmission, distribution, trading (both OTC and exchange) and supply; and emission reduction projects and environmental securities, allowance and certificate trading, as well as related regulatory advice.

Andreas takes an active role in the energy regulatory sector, serving as chairman of several working groups, including the drafting committee for the European Federation of Energy Traders (EFET), the RECS International Legal Task Force, the gas transportation committee of the Association of International Petroleum Negotiators (AIPN), and the Carbon Markets and Investors Association (CMIA) EU Emissions Trading Scheme working group, and he is member of the Renewable Energy Performance Platform advisory panel. Andreas additionally advised one of the participating governments up to and during the Paris Agreement negotiations in 2015.

Andreas has been named ACC/ILO ‘European Counsel of the Year 2013’ (regulatory) and is listed in The Legal 500 for energy and projects.
MUNIR HASSAN

CMS Cameron McKenna Nabarro Olswang LLP

Munir Hassan is head of clean energy at CMS in London, helping to determine the firm’s strategy on renewables and clean generation. Munir has almost 20 years of experience advising the power sector on commercial arrangements, M&A transactions, electricity sector restructurings and reforms, price-regulated energy networks, regional trading arrangements, establishment of regulatory frameworks and wholesale/retail supply arrangements. He has advised on technologies across the power space, including on offshore and onshore wind, solar, tidal, biomass, energy from waste, tidal and tidal lagoon, wave power, CCGT and CHP, coal-fired projects, electricity transmission networks and electricity distribution networks. He has advised extensively on both the sector in the United Kingdom and power projects and market reforms across numerous jurisdictions around the world.

KEISUKE HAYASHI

Anderson Mōri & Tomotsune

Keisuke Hayashi is an associate at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and the University of Tokyo, School of Law (JD) and is admitted to the Bar in Japan (Tokyo Bar Association).

THOMAS HEIDEMANN

CMS Russia

Dr Thomas Heidemann is a Russia and eastern Europe expert. He is based in Düsseldorf and Moscow, where he advises on complex transactions in Russia and in central and eastern European countries. Given his 20 years of experience, Russian and international clients trust him when it comes to cross-border investments to and from Russia. He works on industrial developments, joint ventures and private equity deals, with special know-how in the automotive sector, and he also advises on investments in renewable energies and other Russian industries.

Thomas heads CMS Russia’s German desk in Moscow and the Russian desk in Düsseldorf and, as such, coordinates the German–Russian work in these offices. Before joining CMS, he worked for a large German law firm, where he managed the Russian and Ukrainian practice, with offices in Moscow, Saint Petersburg and Kiev.

WATARU HIGUCHI

Anderson Mōri & Tomotsune

Wataru Higuchi is a partner at Anderson Mōri & Tomotsune. He studied at Hitotsubashi University (LLB) and Columbia Law School (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.

HACHEM EL HOUSSEINI

Abou Jaoude & Associates Law Firm

Hachem El Housseini is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of media, energy, corporate law and aviation.
Throughout his career, Hachem has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Hachem has a particular expertise in the oil and gas industry, and has worked on a number of major oil and gas projects in the region.

He also provides legal advice to the UNDP in the context of the preparation of a legislative framework study for the transport and energy sectors in Lebanon, a component of the SODEL project.

Hachem holds a JD in private law from the Francophone sector of the Lebanese University, and an MBA from ESA/ESCP (Ecole Supérieure des Affaires/Ecole Supérieure de Commerce de Paris). He is a lecturer at the American University of Beirut.

He is admitted to the Beirut Bar Association and the International Bar Association, and is an Associate Member of the Chartered Institute of Arbitrators, London. He is fluent in Arabic, French and English.

NICOLAS JANS
*HVG Law LLP*

Nicolas Jans is an associate at HVG Law and part of the energy and utilities team. He is admitted to the Bar in Amsterdam. Nicolas advises domestic and international companies in a broad range of energy and competition-related procedures against the Dutch energy regulator and competition authorities, usually in an international context. In this regard, Nicolas litigates in the areas of corporate and commercial law, energy law and national and EU competition law with a focus on the field of anti-corruption/fraud and state aid.

RANA KATEB
*Abou Jaoude & Associates Law Firm*

Rana Kateb is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of energy, pharmaceuticals, corporate law, and mergers and acquisitions.

Throughout her career, Rana has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Rana has particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Rana holds an LLB in both private and public law from St Joseph University, and a Diploma of Higher Specialised Studies (DESS) in arbitration and ADR from the Francophone sector of the Lebanese University accredited by Panthéon-Assas University, Paris. She is recommended by The Legal 500.

She is admitted to the Beirut Bar Association, and is fluent in Arabic, French and English.

NICOLAJ KLEIST
*Bruun & Hjejle*

Nicolaj Kleist has extensive experience in advising on regulatory matters and public law issues, especially within the energy sectors, where he advises energy and supply utilities in the areas of oil, gas, electricity, heating and renewables. He regularly assists in disputes before public authorities, complaints boards and the courts, and has assisted in a number of landmark cases regarding price issues.
CHANGWOO LEE
*Yoon & Yang LLC*

Changwoo Lee is a partner at Yoon & Yang LLC. Mr Lee’s main practice focuses on patent litigation, particularly in the energy and life sciences sector. He also has extensive experience in trademark and copyright matters.

KWANG-WOOK LEE
*Yoon & Yang LLC*

Kwang-Wook Lee is a partner at Yoon & Yang LLC. Mr Lee’s main areas of practice include antitrust law, telecommunications and energy, broadcasting and privacy law. Mr Lee represents a broad range of companies in the energy industry. He also has extensive experience providing legal advice concerning issues arising in the environment and clean-tech sector.

PIETER LEOPOLD
*HVG Law LLP*

Pieter Leopold is an associate at HVG Law and part of the energy and utilities team. He is admitted to the Bar in Amsterdam and is a member of the Dutch Association for Energy Law. Pieter studied International and European law at the University of Amsterdam. He litigates and advises national and international clients on energy regulation and competition issues. Pieter also represents clients in proceedings with the regulator. Prior to joining HVG Law, Pieter worked at the Authority for Consumers and Markets in The Hague.

IGA LIS
*CMS*

Iga Lis is a partner in the energy and projects practice, and head of the chemical-sector team at CMS Poland.

Iga is a Polish-qualified advocate with 15 years of professional experience. Her experience in the field of energy and heavy industry mainly includes comprehensive advice on the development, construction and operation based on different contractual structures of new installations in power generation, refining and metallurgical plants. Her experience also includes the preparation and negotiation of various agreements in the multi-contracting and turn-key structure. Iga has represented clients in proceedings based on the Act on Public Procurement Law.

Since working at CMS she has participated in a number of negotiations and preparation of public procurement projects. Her professional experience includes as well advising clients on ongoing corporation-related matters. Iga specialises in drafting and negotiating complex long-term contracts, general terms and tender regulations.

She is a lecturer in environmental protection law postgraduate studies, as well as a coordinator of the ‘New technologies in energy’ module of the law in the business of new technologies postgraduate programme at Łazarski University in Warsaw.
RUTH LOSCH

Linklaters LLP

Ruth Losch is a managing associate of Linklaters LLP and a corporate and energy lawyer in Berlin. She studied law in Osnabruck, Kingston upon Hull, Berlin, Brussels (LLM) and Heidelberg (Doctor Juris) and has been trained as a lawyer in Berlin and Gdansk.

Ruth is an experienced adviser of clients in the public domain on regulatory matters, specialising in energy and public procurement law. She advised several municipalities in awarding concessions for their gas, electricity or district heating grids.

She also specialises in legal knowledge management and regularly publishes and lectures on questions of energy law.

NATASHA LUTHER-JONES

DLA Piper International

Natasha Luther-Jones is co-global chair of the energy and natural resources sector at DLA Piper. She has a strong focus on renewable energy and advises a varied client base including developers, EPC & O&M contractors, solar and wind manufacturers, equity investors, purchasers, sellers and off-takers in respect of development, construction and operational renewable energy projects.

Natasha has been instrumental in developing DLA Piper’s leading practice advising on corporate end-user power purchase agreements (PPAs). She has been involved in numerous corporate end user PPAs, including with high-profile companies in the consumer, telecoms, banking, retail, IT and industrial sectors.

She is listed in The Lawyers’ Hot 100 2017 for Energy and in the Women’s Power List 2017. She is listed as one of the 100 most influential lawyers in the global wind energy industry, in ‘The Legal Power List 2018’ published by the intelligence service A Word About Wind. The independent legal sector rankings from Legal 500 2019, 2018, 2017 and 2016 quote her as ‘a go-to name in the renewable energy space’, ‘fantastic’, ‘forward-thinking’ and a ‘no-nonsense deal maker’. She is also ranked as a ‘leading individual’ in the following Legal 500 categories – London: power (including electricity and renewables) and Yorkshire and the Humber: energy.

CONNOR MCCLYMONT

Squire Patton Boggs

Connor McClymont is an associate in the corporate practice group of Squire Patton Boggs in Perth. He has assisted clients on a range of corporate transactions and advisory matters and has experience assisting international and domestic clients on research, drafting and due diligence.

JULIA BATISTELLA MACHADO

Pinheiro Neto Advogados

Julia is an associate at Pinheiro Neto Advogados and part of the energy team. Julia holds a masters in science in regulation from the London School of Economics and Political Sciences (LSE). In 2016–2017, she worked for the Centre for Analysis of Risk and Regulation (CARR), a consultancy branch of LSE, where she was part of the team developing studies on
public–private partnerships, in connection with the establishment of the Brazilian Investment Partnership Programme. The consultancy was developed together with RAND Europe and with the sponsorship of the UK Prosperity Fund. Julia is also the author of several academic and journalistic papers in areas related to public law and regulation. Her practice in energy focuses on helping clients to understand and mitigate the risks involved in doing business in the Brazilian energy sector in the context of M&A transactions, project financing, regulated auctions, joint ventures, contracts, new project structuring and new business models.

SOURAYA MACHNOUK
Abou Jaoude & Associates Law Firm
Souraya Machnouk is a partner at Abou Jaoude & Associates Law Firm, and lends her specialised knowledge and experience to several practice groups, including mergers and acquisitions, banking, finance, corporate law, telecommunications, and energy.

Throughout her career, Souraya has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Souraya has a particular expertise in the oil and gas industry, and has worked on major LNG-to-power projects in the region.

Souraya holds a JD in private and public law from St Joseph University, a master's degree (DEA) in banking and financial markets law from the University of Paris II-Assas, and a joint Master of Laws degree (LLM) from George Washington and Georgetown Universities. She is recognised as a leading lawyer by The Legal 500, Chambers & Partners and IFLR1000.

She is admitted to the Beirut Bar Association and the International Bar Association, and is fluent in Arabic, French and English.

ANASTASIA MAKAROVA
CMS Russia
Anastasia Makarova is a senior associate in the corporate and M&A practice of CMS Russia. She specialises in corporate law, mainly in M&A. She has broad experience preparing corporate documents and documentation on the structuring and execution of M&A transactions.

Anastasia is also experienced in advising on issues of corporate governance, oil and gas, and subsoil legislation, as well as providing ongoing support to oil companies' business activities and in due diligence on companies of a different asset structure.

She has participated in large M&A projects in the oil and gas, metal and automotive sectors, as well as in large investment projects connected with oil and gas exploration and production.

FIONA MEATON
Squire Patton Boggs
Fiona Meaton practises principally in commercial and corporate law with a focus on energy and resources transactions and projects. In particular, Fiona advises Australian and international clients in relation to project structuring, joint venture arrangements, acquisitions, risk management and due diligence associated with exploration and production activities within Australia as well as power purchase agreements, operations and maintenance agreements and other project documentation relating to power projects. She also advises on corporate law and corporate governance issues. Fiona was a member of the team working on the Ichthys...
LNG transaction, which was named energy and resources deal of the year at the Asian Legal Business Japan Law Awards 2013.

NEERAJ MENON

Trilegal

Neeraj Menon is a partner in the Mumbai office of Trilegal and is a member of Trilegal’s Energy, Infrastructure and Natural Resources team of the firm. His primary areas of practice are energy and infrastructure projects.

In the energy sector, Neeraj has advised the government of India on the policy regime for the conventional power sector and has commented on various government policies in the renewable energy and resources sectors. He has extensively advised the private sector on bidding and developing energy and infrastructure projects including on compliance with environmental legislations, conducting land title verification and on acquisition of real estate.

Neeraj has advised numerous financial and strategic investors, lenders, multilateral agencies and utilities on all aspects of investing, developing and financing solar, wind and hydro power projects. He led the team that advised IFC and Government of Madhya Pradesh on the development of 750MW of Rewa Ultra Mega Solar PV project on PPP basis. This project was recognised in the prestigious government of India’s Prime Minister’s Book of Innovation, 2017 and World Bank Group’s President award for Innovation and Excellence for its innovative PPP transaction structure.

He has also volunteered his legal expertise in matters of public policy and regularly advises industry associations such as World Business Council for Sustainable Development, the Federation of Indian Chambers of Commerce and Industry, the Confederation of Indian Industry, US-India Business Council and Indo-French Chamber of Commerce & Industry on policy and regulatory issues in the energy and infrastructure sectors.

Neeraj is an alumnus of Symbiosis Law School, Pune University and a member of Bar Council of Delhi, India. He is a member of CII’s National Committee on Renewable Energy. He has co-authored the India chapters in successive editions of The Energy Regulation and Markets Review (since 2012) Getting the Deal Through: Electricity Regulation (since 2015) and Getting the Deal Through: Mining (2017).

ANTONIO MORALES

Baker McKenzie

Antonio Morales is the head of the public and regulatory practice in the Spanish offices of Baker McKenzie. Mr Morales’ practice focuses on projects and transactions relating to public and administrative law, including the energy, utility, water and telecommunications sectors.

In 1997, Mr Morales became a state attorney. During his time in the public administration, he worked at the government delegation in Madrid from 1998 to 1999 and from 1999 to 2002 at the Superior Court of Justice of Madrid. From 2002 and 2005 he served as secretary general of the Spanish Nuclear Safety Council. Prior to joining Baker McKenzie, Mr Morales was a partner at Latham & Watkins and Hogan Lovells. In 2008, Mr Morales obtained his PhD at the Autonomous University of Barcelona (UAB). Mr Morales has been recognised as a leader in administrative and public law by Chambers Global for the past eight years, and in the energy sector by Chambers Europe from 2008 to 2015. Additionally, he was recognised as a leading Iberian energy lawyer by Iberian Lawyer in June 2006 and in 2007 he also received Iberian Lawyer’s ‘40 under Forty’ award. Mr © 2019 Law Business Research Ltd
Morales was commended by *Chambers Europe* in 2011 for being ‘a lawyer with tremendous expertise’ and for the ease with which he ‘explains the most complex legal issues to clients with staggering clarity and simplicity’ and ‘total dedication to the client’s needs’.

**LUIS HORACIO MORENO IV**  
*Alfaro Ferrer & Ramírez*

Luis Horacio Moreno IV is an associate at Alfaro Ferrer & Ramírez. He has been an associate at AFRA since 2010, concentrating his practice on the areas of acquisition and procurement law; government concessions and permits; telecommunications law; public transportation; energy law; administrative law; infrastructure; contracts: and general commercial law.

Luis is also a professor of administrative law at Santa María La Antigua Catholic University (USMA). He obtained his Bachelor of Law and Political Science at USMA in 2009, after which he went to Duke University School of Law and obtained a Master of Laws (LLM) in 2010. He obtained a Master of Law (LLM) in tax law from the Specialized University of Certified Public Accountants (UNESCPA) in 2013, and a Master of Business Administration for Law Firms (MBA) from the Superior Institute of Law and Economics (ISDE) in 2015. In 2017, Luis received his Certificate in Public Procurement Law from the Latin University of Panama, and the Certificate from the Public–Private Partnerships: Implementing Solutions in Latin America and the Caribbean (ES), from the Public–Private Partnerships programme of the Inter-American Development Bank (IDB edX).

Mr Moreno is a member of the Panama Bar Association, the International Bar Association and the Panamanian Association of Business Executives (APEDE). He was chair of the Legislation and Taxation Committee of the American Chamber of Commerce and Industry of Panama (AMCHAM) in 2015 and 2016, Secretary of the Administrative Law Commission of the Panama Bar Association in 2016, Secretary of the Law Commission of APEDE in 2017/2018 and Director and Secretary of AMCHAM in 2017–2018.

**CHARLES MORRISON**  
*DLA Piper International*

Charles Morrison is a trade and project finance lawyer qualified in England and Wales, and is international group head of the finance and projects practice at DLA Piper. He has a particular focus on energy work, especially oil and gas, and his energy experience extends to upstream, midstream and downstream oil and gas, power projects, and the related financing. His clients include governments, oil companies, trading houses, banks and other financial institutions. Charles is a partner in the energy and infrastructure finance team, and was previously head of the Africa group, as well as head of the energy infrastructure finance and commodities team.

Charles appears regularly in the principal legal directories and awards. He has headed a number of teams in major international energy and infrastructure projects, and has significant experience throughout Africa. He was rated ‘leading individual’ in the 2013 *The Legal 500* United Kingdom awards, commended as a ‘respected practitioner’ and for ‘thorough commercial advice’, and was appointed by the British government (DFID) and Uganda’s central bank, the Bank of Uganda, as an inspector to review the sale of Uganda Commercial Bank to Stanbic Bank Uganda.
KARTHY NAIR

Trilegal

Karth Nair is a senior associate in the Mumbai office of Trilegal and is a member of Trilegal’s energy, infrastructure and natural resources team of the firm.

She has experience in advising clients on financing and projects in a variety of sectors including power and road infrastructure. She has international experience, having worked in CMS Cameron McKenna in their London office for two years.

Her role has involved conducting due diligence and drafting, reviewing and participating in negotiation of transaction documents, and liaising with various regulatory authorities.

Karth is an alumnus of National University of Juridical Sciences, Kolkata. She is a member of the Bar Council of Andhra Pradesh.

J PATRICK NEVINS

Latham & Watkins LLP

Latham partner Patrick Nevins has over 25 years of experience advising leading energy companies in the development of major infrastructure projects, administrative litigation and high-stakes regulatory matters. His clients have included companies in all segments of the natural gas industry including pipeline companies, LNG project developers, local distribution companies, producers, as well as oil and liquids pipelines and shippers. He is consistently recognised as a leading energy regulatory and oil and gas lawyer in Chambers Global, Chambers USA, The Legal 500 United States, Who’s Who Legal, Best Lawyers and Euromoney’s ExpertGuides.

OKECHUKWU J OKORO

G Elias & Co

Okechukwu J Okoro is a senior associate in the law firm of G Elias & Co. He holds a Bachelor of Laws degree from Ebonyi State University.

He has been involved in several of the firm’s energy deals. He has in the last two years advised on at least six renewable energy projects. Okechukwu J Okoro was also on the team that advised on a US$1.2 billion ‘gas-to-power’ project financing and a US$1.5 billion refinancing of NNPC petroleum product import receivables. He is recently advised the Transmission Company of Nigeria on the Eligible Customer Regulation 2017. He is currently advising a Shell Nigeria entity, focused on intervention programmes to address access to energy challenge in Nigeria, and on sundry renewable energy issues, investments and support for renewable energy in Nigeria. He is also on the team advising a fund set up by the Association of European Development Finance Institutions (EDFI) – ElectriFi, on its energy support projects in Nigeria.

JOSÉ ROBERTO OLIVA JR

Pinheiro Neto Advogados

José Roberto Oliva Jr is a partner at Pinheiro Neto Advogados, in the energy team. He has more than 18 years of experience advising clients on matters related to the energy industry. His practice focuses mainly on energy regulation, project finance and M&A. He has extensive experience in assisting clients in domestic and international mergers and acquisitions, project
development, financing, private equity investments, joint ventures, and a variety of other matters related to energy and infrastructure projects. He is consistently ranked among the nation's top energy lawyers by *Chambers Latin America* and *Chambers Global, The Legal 500* and *IFLR1000*. He holds a bachelor of laws (LLB) from the University of Rio de Janeiro and two master’s degrees – a master of laws (LLM) from Insper (Institute of Education and Research), São Paulo and an LLM from the University of California, Berkeley. He is deputy general counsel for the Brazilian Association of Independent Power Producers (APINE), a member of the Energy Committee of the Brazilian Bar Association (OAB/RJ) and a member of the Brazilian Institute of Energy Law (IBDE).

DAVID E PETTIT
*Latham & Watkins LLP*

Latham senior associate David E. Pettit has represented independent power producers, utilities, project developers and financial institutions in regulatory and transactional matters involving electric generation, transmission and distribution issues, as well as related natural gas transportation and distribution issues.

Mr Pettit regularly represents clients before the Federal Energy Regulatory Commission and various state public utility commissions regarding a broad range of matters affecting the electric industry and focuses on federal and state financing support and incentive programmes for clean energy technologies, products and services.

GEORGES RACINE
*HFW*

Georges Racine is a partner at HFW. He is a dual-qualified civil and common law lawyer entitled to practise in Switzerland, France, the United Kingdom and Canada (Quebec). He has wide-ranging experience in corporate, commercial and international business law, with particular emphasis on projects (energy, infrastructure, telecoms and transport), construction, licensing and concessions, privatisations, mergers and acquisitions, joint ventures, public-private partnerships (PPPs), foreign investment and international trade. Mr Racine has acted as lead counsel in international projects and transactions in over 25 countries worldwide. He was a member of the expert group that advised the Secretariat of the United Nations Commission on International Trade Law (UNCITRAL) on its draft Legislative Guide on Privately Financed Infrastructure Projects. He has written several articles on energy, infrastructure, telecommunications, PPPs and other subjects for international publications and attended several international conferences as a speaker. He has also acted for several international investment banks, international financial institutions (e.g., the World Bank, IFC, EBRD), foreign governments, regulatory authorities, sponsors, developers, independent power producers, utilities, trading firms, contractors, service providers, suppliers, investors and consulting, engineering and accounting firms.

FILIP RADU
*CMS Cameron McKenna Nabarro Olswang LLP*

Filip Radu is an associate at CMS in London, practising in the firm’s energy projects and construction department, focusing on the power sector. Filip has advised on both conventional
About the Authors

and renewable power projects around the world, acting for UK and international utilities, developers, financiers, governments and regulators. He also has experience advising on market reform, helping enshrine international best practice into national energy rules, regulations and legislation. Filip’s experience also spans M&A transactions within the energy sector, advising on corporate, regulatory and commercial matters.

KRISHNA RAMACHANDRA

Duane Morris & Selvam LLP

Krishna Ramachandra is managing director of Duane Morris & Selvam LLP in Singapore and of Duane Morris & Selvam (Myanmar) Limited. He is head of the corporate and TMT practice groups and serves as a team lead for the fintech industry group. His practice includes M&A and capital markets, investments funds, private equity, financial technology and TMT. Krishna also has significant experience in Myanmar, Indonesia, Malaysia, Taiwan and Korea.

Krishna was named one of Singapore’s top 100 lawyers by Asia Business Law Journal 2018. He is regarded as one of the most highly recommended lawyers in the practice areas of capital markets (foreign firms), corporate/M&A (local/foreign firms) and TMT (local firms) in Singapore by The Legal 500 Asia Pacific and Chambers Asia-Pacific. Krishna is also recognised as a leading individual for corporate/M&A (domestic) in Singapore by Chambers Global 2019. In Myanmar, he is regarded as a leading lawyer in corporate/M&A since 2016 and a recommended lawyer in projects (including energy) by The Legal 500 Asia Pacific. IFLR1000 2019 also named Krishna as a highly regarded lawyer in Singapore capital markets.

Krishna is an advocate and solicitor of the Supreme Court of Singapore and a solicitor of England and Wales.

SIMON REAR

Squire Patton Boggs

Simon Rear is a partner in the corporate practice group of Squire Patton Boggs in Perth. He has broad experience in private and public M&A, equity capital markets and general corporate advisory work in both Australia and the United Kingdom. He has advised in connection with takeovers, schemes of arrangement and private M&A transactions. He has also advised on a number of fundraisings including IPOs, rights issues and placements acting for both issuers and underwriters.

Simon’s expertise has been consistently recognised by leading legal directories, including Doyle s and The Legal 500 Asia Pacific for corporate and M&A, and recommended in The Legal 500 Asia Pacific 2018 in corporate and M&A, Australia, energy (transactions and regulatory), Australia and natural resources (transactions and regulatory), Australia.

MYRIA SAARINEN

Latham & Watkins AARPI

Myria Saarinen is a partner in the litigation department of the Paris office of Latham & Watkins.

Ms Saarinen’s practice focuses on resolving a broad range of complex disputes through litigation proceedings, mostly in an international context, and in various areas of business, including in the energy sector.
JULIA SACK

*Linklaters LLP*

Julia Sack is a managing associate of Linklaters LLP in Berlin. Before she joined Linklaters in 2013, Julia studied law at the Humboldt-University of Berlin and did her legal traineeship at the higher regional court of Berlin. In addition, she is a graduate of the North Sea Energy Law Programme and holds a Master’s degree from the universities of Groningen, Copenhagen, Aberdeen and Oslo.

Julia advises international clients on M&A transactions and joint ventures in the energy sector as well as on various regulatory matters of European and German energy law. She has advised, for example, Macquarie European Infrastructure Fund 3 in connection with the indirect sale of their shares in the German gas transmission operator Thyssengas GmbH, L1 Energy on the acquisition of RWE Dea from RWE, and several European gas storage operators on the regulatory aspects of gas storages, regulatory compliance of new trading models and on adjustment of long-term contracts. Moreover, she has prepared an opinion for the German energy regulator analysing the activities of an energy supplier and its group companies. In addition, Julia regularly publishes and gives presentations in the field of energy law.

THOMAS SCHULZ

*Linklaters LLP*

Thomas Schulz is a partner of Linklaters LLP and a corporate and energy lawyer in Berlin. He studied in Würzburg, Liverpool and Hamburg and has been trained as a lawyer in Brussels, Moscow and Beijing.

Thomas advises utilities, financial investors, project developers and banks on M&A, joint ventures, project developments and financings as well as contract law and regulation in the energy sector. He has in particular advised on numerous renewable energy projects and conventional power plants in Germany and abroad as well as electricity and gas grid transactions.

DAVID I. SCHWARTZ

*Latham & Watkins LLP*

David Schwartz is a partner in the finance department of Latham & Watkins’ Washington, DC office. He serves as global chair of the energy regulatory and markets practice, is a member of the project finance group, and is co-chair of the firm’s global power industry group. He has extensive experience representing entities involved in electric generation, transmission and distribution, electric and gas marketing and trading, and gas transportation and distribution.

Mr Schwartz has been active in the formation of the developing electricity markets in the United States; led transactional and regulatory teams in mergers and acquisitions and divestitures of energy companies and assets; litigated contract, rate and transmission access disputes; and drafted federal and state energy legislation. He also has extensive experience in negotiating power purchase and sale agreements, electric transmission agreements, natural gas transportation agreements, energy management agreements, and electric and gas interconnection agreements.

Mr Schwartz regularly advises clients on energy matters before the Federal Energy Regulatory Commission, various state public utility commissions, and the Department of Energy.
Mr Schwartz is regularly named as a leading energy lawyer in Corporate Counsel magazine, The Best Lawyers in America, The Legal 500 United States and both the global and the US Chambers & Partners guides to leading business lawyers. Mr Schwartz is a member of the American Bar Association and has held leadership positions in the Energy Bar Association.

SANDER SIMONETTI

HVG Law LLP

Sander Simonetti is a partner at HVG Law and heads the energy and utilities team. He graduated from Leiden University and was a fellow (energy and climate law) at the European University Institute in Florence. Sander advises national and international companies and governments on regulation, transactions, disputes and projects in the energy and natural resources industry. He handles complex deals right across the sector and advises on the full range of energy-related issues and projects, including wind, solar, geothermal and biomass, as well as oil and gas, LNG, district heating and co-siting.

ANNA SIVKOVA

CMS Russia

Anna Sivkova is an associate in the corporate and M&A practice of CMS Russia. Anna specialises in natural resources legislation and corporate law. She has broad experience in the preparation of documentation for deal structuring and M&A in all sectors, including oil and gas.

Anna has participated in large M&A transactions in the oil and gas sector, as well as in large investment projects for the exploration and production of hydrocarbons.

SHAGHAYEGH SMOUSAVI

CMS Hasche Sigle

Shaghayegh Smousavi is partner at CMS Germany. Her work focuses on cross-border transactions and financing, in the energy sector in particular. She has special, local know-how and experience in advising international companies both on taking up operations in Iran and on re-entering the Iranian market.

Shaghayegh started her legal career with an international accountancy firm in Frankfurt and Paris, and then worked for a tax consultancy in Niamey in Niger, as well as for the European Commission in Brussels. She subsequently joined Clifford Chance, where she worked as a counsel in her final post there before joining CMS Germany.

PRIYANK SRIVASTAVA

Duane Morris & Selvam LLP

Priyank Srivastava is special counsel in the corporate and energy practices with over ten years’ experience advising in the energy and project development/infrastructure/P3 sector. Priyank focuses his practice on upstream, midstream and downstream oil and gas/LNG matters and the power sector. Having worked for over eight years at India’s largest exploration and production company, he is familiar with all the transactional aspects of global energy projects.
Priyank has considerable on-the-ground experience of advising clients in various sectors in Myanmar, including energy and power projects, infrastructure, telecoms and project financing matters. He has rich experience of the local regulatory regime of Myanmar and has been actively involved in dealing with various government authorities.

Priyank’s core areas of practice include cross-border mergers and acquisitions transactions in relation to oil and gas and energy and infrastructure projects. His practice covers acquisitions, joint ventures, project development and project finance within the oil and gas, mining, power and infrastructure sectors. He is fluent in Hindi and English and knows elementary Burmese and Spanish.

**CHADI STEPHAN**

*Abou Jaoude & Associates Law Firm*

Chadi Stephan is a senior associate at Abou Jaoude & Associates Law Firm, practising in the areas of energy, corporate law, and mergers and acquisitions.

Throughout his career, Chadi has advised key companies with respect to various aspects of their onshore and offshore business. In the energy sector, Chadi has a particular expertise in the electricity industry, and has worked on a number of major power projects in the region.

Chadi holds an LLB in both private and public law from the Holy Spirit University of Kaslik (USEK), and a Diploma of Higher Specialised Studies (DESS) in international agreements from USEK accredited by the University of Montpellier.

He is admitted to the Beirut Bar Association, and is fluent in Arabic, French and English.

**MONICA SUN**

*Herbert Smith Freehills LLP*

Monica Sun, a partner at Herbert Smith Freehills in the global energy practice in Beijing, has experience of advising on oil and gas (including LNG), power, renewables, mining, infrastructure projects and transactions around the world, in particular advising major Chinese companies on their outbound investment. Her clients include major Chinese state-owned enterprises such as Sinopec, CNOOC, CNPC, State Grid, Huaneng, Huadian, Shenhua, Minmetals, SRF, Power China, CMC and CMEC. Her practice covers M&A, joint ventures, project development and project finance, private equity investment, corporate law and corporate finance. She also has considerable experience in advising foreign clients on doing business in China. Monica has advised on acquisitions and projects in regions including China, Australia, Indonesia, Africa, the former Soviet Union, south America, the United Kingdom and other key markets along the routes of the Belt and Road Initiative.

**ADA SZON**

*CMS*

Ada Szon is a lawyer in the energy and projects practice at CMS Poland.

Ada specialises in advising energy-sector entities on broadly understood regulatory issues, including issues related to licensing and business tariffs, renewable energy and capacity mechanisms. She advised Polish power generators with regard to the European Commission’s ‘Clean Energy for All Europeans’ legislative package.
She also supports energy-sector companies during proceedings between them and the President of the Energy Regulatory Authority, in administrative proceedings and in challenges to the Energy Regulatory Authority’s decisions before the common courts.

Ada also has experience in environmental law, primarily in issues related to industrial emissions, carbon trading, waste management and water and sewage management. She took part in due diligence processes concerning networks of waste treatment plants as well as wind farms.

**KEI TAKADA**  
*Anderson Mōri & Tomotsune*

Kei Takada is an associate at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (BEc) and the University of Tokyo, School of Law (JD) and is admitted to the Bar in Japan (Dai-ichi Tokyo Bar Association).

**REIJI TAKAHASHI**  
*Anderson Mōri & Tomotsune*

Reiji Takahashi is a partner at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and the University of Virginia (LLM). He is a lecturer at the University of Tokyo School of Law and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association) and New York.

**NORIFUMI TAKEUCHI**  
*Anderson Mōri & Tomotsune*

Norifumi Takeuchi is a partner at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and University of London (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association).

**QIUJIE TAN**  
*Herbert Smith Freehills LLP*

Qiujie Tan is an associate at Herbert Smith Freehills’ global energy group based in Beijing. Qiujie works closely with multinational clients and Chinese corporations advising on outbound and inbound deals in the oil and gas, power, renewables, mining and infrastructure sectors. She has advised clients on M&A and projects development in regions including China, Indonesia, Russia, the Middle East, the United Kingdom and Australia.

**FREDERIK VANDENDRIESSCHE**  
*Stibbe*

Frederik Vandendriessche, a partner at Stibbe, has a firm command of energy law, energy contracts and the regulatory framework applicable to the energy sector. He has relevant expertise with regard to on- and offshore renewable energy projects, energy efficiency projects, grid operation and construction, pipelines, mining, nuclear energy, energy commodity trading, CO₂ emission trading and the EU ETS. He has a mandate at the University of Ghent where he gives the energy law course. Frederik is a member of the Energy Law Research
Forum, an international group of scientists from the European Union, active in the field of energy law research.

**DICK WEIFFENBACH**  
*HVG Law LLP*

Dick Weiffenbach is senior partner at HVG Law, and energy and utilities sector leader of the global EY Law network of law firms associated with EY. He graduated from the universities of Leiden and Utrecht and is a Harvard Business School alumnus. Dick is member of the Dutch Association for Energy Law and advises national and international energy companies in the field of contract law, corporate law, energy law and regulatory affairs, including licensing and tariff regulation. He has supervised the unbundling of several Dutch energy companies.

**SHARON WING**  
*Covington & Burling (Pty) Ltd*

Sharon Wing is a corporate and project finance lawyer in Covington’s Johannesburg office. She has experience working on traditional and renewable energy projects, corporate transactions and various renewable energy and mining projects across Africa.

**SOONG-KI YI**  
*Yoon & Yang LLC*

Soong-Ki Yi is a partner at Yoon & Yang LLC, Mr Yi’s main areas of practice include mergers and acquisitions, corporate finance, foreign investment, and information and data protection. He also has extensive experience in the areas of energy, telecommunications and broadcasting, and regulatory matters.

**KUNIHIRO YOKOI**  
*Anderson Mōri & Tomotsune*

Kunihiro Yokoi is a special counsel at Anderson Mōri & Tomotsune. He studied at the University of Tokyo (LLB) and University of California, Los Angeles, School of Law (LLM) and is admitted to the Bar in Japan (Dai-ni Tokyo Bar Association).

**JOSÉ VICENTE ZAPATA**  
*Holland & Knight*

José Vicente Zapata is a partner in Holland & Knight’s Bogota office with more than 20 years of experience in the natural resources sector. He focuses his practice on corporate and commercial matters with an emphasis on the environment, energy and natural resources. Mr Zapata primarily represents government organisations as well as electric, oil, gas, mining, agrochemical and industrial companies. In addition, he regularly advises clients in the structuring of foreign investment transactions, corporate reorganisations, and mergers and acquisitions as well as matters of environmental liability and judicial proceedings such as class action lawsuits. He has represented clients in many of the largest transactions made in Colombia to date in the mining, oil and gas sectors, in addition to assisting a range of companies in obtaining mining and oil and gas concessions. Utilising his extensive experience
in contract negotiations, Mr Zapata has assisted numerous government agencies both in defining the terms and conditions of regulations and in sensitive international judicial cases. Mr Zapata has participated in critical environmental liability cases and class action litigation in Colombia. Of particular importance is his participation in complex cases where communities and companies discuss their corresponding rights and in prior public consultations.

JAMES ZHANG

Herbert Smith Freehills LLP

James Zhang is a member of Herbert Smith Freehills’ global energy practice in Beijing. He has worked across Herbert Smith Freehills’ offices in London, Hong Kong and Beijing and is admitted as a solicitor in England and Wales. James has advised clients on upstream oil and gas (including LNG) projects in Africa, the United Kingdom, north and south America, South-East Asia, the Middle East, Australia and China, in respect of equity M&A, project development, project operation, tie-in facilities and joint venture arrangements. James also has extensive experience in project development and finance on power, roads and railway projects in multiple jurisdictions.
CONTRIBUTORS’ CONTACT DETAILS

ABOU JAOUDE & ASSOCIATES
LAW FIRM
OMT Building
266 Sami El Solh Avenue
PO Box 116-5079
Beirut
Lebanon
Tel: +961 1 395555
Fax: +961 1 384064
s.machnouk@ajalawfirm.com
h.elhousseini@ajalawfirm.com
r.kateb@ajalawfirm.com
c.stephan@ajalawfirm.com
www.ajalawfirm.com

AFRIDI & ANGELL
Jumeirah Emirates Towers
Office Tower, Level 35
Sheikh Zayed Road
Dubai
United Arab Emirates
Tel: +971 4 330 3900
Fax: +971 4 330 3800
m afridi@afridi-angell.com
aaloke@afridi-angell.com
www.afridi-angell.com

ALFARO FERRER & RAMÍREZ
AFRA Building
Ave Samuel Lewis and 54 Street
Panama City
Panama
Tel: +507 263 9355
Fax: +507 263 7214
abarcenas@afra.com
lhmoreno@afra.com
www.afra.com

ANDERSON MŌRI & TOMOTSUNE
Otemachi Park Building
1-1-1 Otemachi, Chiyoda-ku
Tokyo 100-8136
Japan
Tel: +81 3 6775 1000
reiji.takahashi@amt-law.com
norifumi.takeuchi@amt-law.com
kunihiro.yokoi@amt-law.com
wataru.higuchi@amt-law.com
keisuke.hayashi@amt-law.com
kei.takada@amt-law.com
www.amt-law.com
Contributors’ Contact Details

BAKER MCKENZIE
José Ortega y Gasset, 29
Madrid 28006
Spain
Tel: +34 91 230 4500
Fax: +34 91 391 5149
antonio.morales@bakermckenzie.com
www.bakermckenzie.com

BRUUN & HJEJLE
Nørregade 21
1165 Copenhagen K
Denmark
Tel: +45 33 34 50 00
Fax: +45 33 34 50 50
nkl@bruunhjejle.dk
www.bruunhjejle.com

CMS
CMS Hasche Sigle
Breite Straße 3
40213 Dusseldorf
Germany
Tel: +49 211 49 34 415
Fax: +49 211 49 34 120
shaghayegh.smousavi@cms-hs.com

CMS Cameron McKenna Nabarro
Olswang LLP
Cannon Place
78 Cannon Street
London EC4N 6AF
United Kingdom
Tel: +44 20 7367 3000
Fax: +44 20 7367 2000
munir.hassan@cms-cmno.com
filip.radu@cms-cmno.com

Warsaw Financial Centre
ul. Emilii Plater 53
00-113 Warsaw
Poland
Tel: +48 22 520 5555
Fax: +48 22 520 5556
iga.lis@cms-cmno.com
ada.szon@cms-cmno.com

CMS Russia
Naberezhnaya Tower, Block C
10 Presnenskaya Nab.
123112 Moscow
Russia
Tel: +7 495 786 4000
Fax: +7 495 786 4001
thomas.heidemann@cmslegal.ru
dmitry.bogdanov@cmslegal.ru
anastasia.makarova@cmslegal.ru
anna.sivkova@cmslegal.ru
www.cms.law

COVINGTON & BURLING (PTY) LTD
Rosebank Link
173 Oxford Road, 7th Floor
Johannesburg 2196
South Africa
Tel: +27 11 282 0860
lfontana@cov.com
swing@cov.com
www.cov.com

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Contributors’ Contact Details

DLA PIPER INTERNATIONAL
160 Aldersgate Street
London
EC1A 4HT
United Kingdom
Tel: +44 20 7796 6444 (C Morrison)
Tel: +44 11 3369 2978 (N Luther-Jones)
Tel: +44 20 7796 6062 (A Gunst)
Fax: +44 20 7796 6666
andreas.gunst@dlapiper.com
natasha.luther-jones@dlapiper.com
charles.morrison@dlapiper.com
www.dlapiper.com

HERBERT SMITH FREEHILLS LLP
28th Floor Office Tower
Beijing Yintai Centre
2 Jianguomenwai Avenue
Chaoyang District
Beijing 100022
China
Tel: +86 10 6535 5000
Fax: +86 10 6535 5055
monica.sun@hsf.com
james.zhang@hsf.com
qiu.jie.tan@hsf.com
www.herbertsmithfreehills.com

DUANE MORRIS & SELVAM LLP
16 Collyer Quay #17-00
Singapore 049318
Phone: +65 9822 5011 / +65 6311 0074
Fax: +65 6311 0058
kramachandra@duanemorrisselvam.com
psrivastava@duanemorrisselvam.com
www.duanemorrisselvam.com

HFW
13-15 Cours de Rive
1204 Geneva
Switzerland
Tel: +41 22 322 48 00
Fax: +41 22 322 48 88
georges.racine@hfw.com
www.hfw.com

G ELIAS & CO
6 Broad Street
Lagos
Nigeria
Tel: +2341 460 7890
Tel: +2341 280 6970
Fax: +2341 280 6972
gbolahan.elias@gelias.com
okechukwu.okoro@gelias.com
www.gelias.com

HOLLAND & KNIGHT
Carrera 7 #71-21
Torre A, Piso 8
Bogotá
Colombia
Tel: +57 1 745 5720
Fax: +57 1 541 5417
jose.zapata@hklaw.com
daniel.fajardo@hklaw.com
www.hklaw.com

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© 2019 Law Business Research Ltd
HVG LAW LLP
Antonio Vivaldistraat 150
1083 HP Amsterdam
The Netherlands
Tel: +31 88 407 04 44
Fax: +31 88 407 04 45
sander.simonetti@hvglaw.nl
nicolas.jans@hvglaw.nl
pieter.leopold@hvglaw.nl
www.hvglaw.nl/nw/en/home

LATHAM & WATKINS
Latham & Watkins AARPI
45 rue Saint-Dominique
Paris 75007
France
Tel: +33 1 4062 2000
Fax: +33 1 4062 2062
fabrice.fages@lw.com
myria.saarinen@lw.com

Latham & Watkins LLP
555 Eleventh Street, NW
Suite 1000
Washington, DC 20004-1304
United States
Tel: +1 202 637 2200
Fax: +1 202 637 2201
david.schwartz@lw.com
tyler.brown@lw.com
michael.gergen@lw.com
natasha.gianvecchio@lw.com
patrick.nevins@lw.com
david.pettit@lw.com
www.lw.com

LINKLATERS LLP
Potsdamer Platz 5
10785 Berlin
Germany
Tel: +49 30 21496 0
Fax: +49 30 21496 100
thomas.schulz@linklaters.com
julia.sack@linklaters.com
ruth.losch@linklaters.com
www.linklaters.de

PINHEIRO NETO ADVOGADOS
Rua Hungria, 1100
01455-906 São Paulo, SP
Brazil
Tel: +55 11 3247 8400
Fax: +55 11 3247 8600
joliva@pn.com.br
jbmachado@pn.com.br
www.pinheironeto.com.br

SQUIRE PATTON BOGGS
Level 21
300 Murray Street
Perth WA 6000
Australia
Tel: +61 8 9429 7444
Fax: +61 8 9429 7666
simon.rear@squirepb.com
fiona.meaton@squirepb.com
connor.mcclymont@squirepb.com
www.squirepattonboggs.com

STEPHENSON HARWOOD MIDDLE EAST LLP
Office 1302, 13th Floor
Burj Daman Building
Happiness Street
Dubai
United Arab Emirates
Tel: +971 4 407 3900
Fax: +971 4 327 6714
salem.chalabi@shlegal.com
www.shlegal.com
Contributors' Contact Details

**STIBBE**
Central Plaza  
Loksumstraat 25 rue de Loxum  
1000 Brussels  
Belgium  
Tel: +32 2 533 53 14  
Fax: +32 2 533 53 84  
frederik.vandendriessche@stibbe.com  
cedric.degrief@stibbe.com  
www.stibbe.com

**STUDIO LEGALE VILLATA, DEGLI ESPOSTI E ASSOCIATI**
Via San Barnaba, 30  
Milan 20122  
Italy  
Tel: +39 02 54 92 951  
Fax: +39 02 54 62 107

Via G. Caccini, 1  
Rome 00198  
Italy  
Tel: +39 06 48 90 67 66  
Fax: +39 06 47 82 16 84

Galleria G. Marconi, 1  
Bologna 40122  
Italy  
Tel: +39 051 23 11 56  
Fax +39 051 04 20 457

a.degliesposti@vilde.it  
www.vilde.it

**TRILEGAL**
Peninsula Business Park  
17th Floor, Tower B  
Ganpat Rao Kadam Marg  
Lower Parel (West)  
Mumbai 400 013  
India  
Tel: +91 22 4079 1000  
Fax: +91 22 4079 1098  
neeraj.menon@trilegal.com  
karty.nair@trilegal.com  
www.trilegal.com

**YOON & YANG LLC**
ASEM Tower  
517 Yeongdong-daero  
Gangnam-gu  
Seoul 06164  
Korea  
Tel: +82 2 6003 7000  
Fax: +82 2 6003 7800  
soongki@yoonlyang.com  
kwlee@yoonlyang.com  
cwlee@yoonlyang.com  
www.yoonlyang.com