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International oil and gas law is a fascinating field, sitting at an intersection of law, politics and business. Practitioners in this field must be familiar not only with international norms and practices, but also local legal and regulatory requirements that can vary substantially from jurisdiction to jurisdiction. The task can be daunting, especially in the context of fast-paced transactions or urgent legal or operational issues.

The Oil and Gas Law Review is intended to serve as a starting point for practitioners in gaining an understanding of the key legal requirements in the jurisdictions in which they may be advising clients on transactional and operational matters. The thinking behind the sub-topics it covers has been to try to answer those questions that come up most frequently when dealing with a new or unfamiliar jurisdiction. Although not a substitute for detailed local law advice, the hope nevertheless is that it will serve as a reference guide and point users in the right direction when considering local legal issues.

I would like to thank the many experts who contributed to this volume. Without their substantial efforts, a work such as this would not be possible. Thanks also to the editors and publishers of The Oil and Gas Law Review for having the vision to publish a volume such as this and for their efforts in making it such a success.

Christopher B Strong
Vinson & Elkins LLP
London
October 2019
Chapter 1

ABU DHABI

James Comyn and Patricia Tiller

I INTRODUCTION

The United Arab Emirates (the UAE) produced an average of 3 million barrels of crude oil per day in 2018, maintaining its position as the fourth-ranked OPEC member in terms of crude oil production. Ninety-five per cent of the UAE’s proven oil reserves are based in the emirate of Abu Dhabi (Abu Dhabi), one of the seven emirates of the UAE, and Abu Dhabi’s production accounts for almost all, if not all, of the oil exported from the UAE.

The UAE’s first oil concession was granted on 11 January 1939. This agreement covered the entirety of Abu Dhabi, both onshore and offshore. The agreement was followed by similar agreements in respect of the other emirates of the UAE. Those subsequent agreements were, however, relinquished after the Second World War, as were the offshore rights in Abu Dhabi. Abu Dhabi entered into its second oil concession agreement on 9 March 1953, which covered its offshore areas. After a number of amendments, relinquishments and extensions, Abu Dhabi's original onshore concession expired on 10 January 2014, 75 years after its initial grant. Between 2015 and 2017, interests in a new onshore concession were granted to Total (10 per cent), BP (10 per cent), CNPC (8 per cent), Inpex Corporation (5 per cent), GS Energy (3 per cent) and CEFC (4 per cent), with Abu Dhabi National Oil Company (ADNOC) retaining a 60 per cent interest.

The expiry of Abu Dhabi's original principal offshore concession occurred in 2018. Upon its expiry, the concession area was divided into three areas, and interests totalling 40 per cent were granted to international oil companies, with ADNOC retaining a 60 per cent interest in each new concession area. The international oil companies that were granted participating interests are:

a in Um Shaif and Nasr: Total (20 per cent), PetroChina (10 per cent) and Eni (10 per cent);

b in Lower Zakum: PetroChina (10 per cent), Inpex (10 per cent), a consortium led by ONGC Videsh (10 per cent), Total (5 per cent) and ENI (5 per cent); and

c in Satah Al Razboot (SARB) and Umm Lulu: Cepsa (20 per cent) and OMV (20 per cent).

1 James Comyn and Patricia Tiller are partners at Hunton Andrews Kurth LLP.
In 2018, the Abu Dhabi government announced a public competitive bidding round for additional blocks. Blocks were awarded to:

- a consortium led by Italy’s Eni and Thailand’s PTT Exploration and Production Public Company Limited;
- Occidental Petroleum;
- Inpex Corporation of Japan; and
- a consortium of two Indian oil companies, Bharat Petroleum Corporation Limited and Indian Oil Corporation Limited.

These grants mark the continuation of a trend that has seen the increasing participation both of the international national oil companies of Asian oil importing nations and of oil companies in which an Abu Dhabi government-owned entity has a preexisting ownership interest or joint venture. A further competitive bidding round was announced by ADNOC in May 2019.

In addition, ADNOC has focused on its midstream and downstream operations. In midstream, it brought in institutional investors to inject US$4.9 billion in ADNOC’s crude pipeline infrastructure and has announced that it is building the world’s largest single underground project for oil storage, with a capacity of 42 million barrels of crude oil, in the emirate of Fujairah on the eastern coast of the UAE. In addition, ADNOC has announced a strategic investment in global storage terminal owner and operator VTTI BV alongside, among others, Vitol.

In the downstream sector, Eni and OMV have acquired 20 per cent and 15 per cent shares respectively in ADNOC Refining, which refines in excess of 922,000 barrels per day of crude and condensate at its Ruwais and Abu Dhabi-based refineries.

This chapter provides an overview of the legal regime in Abu Dhabi as it relates to oil and gas investment.

II LEGAL AND REGULATORY FRAMEWORK

i Constitutional framework

Article 23 of the Constitution of the UAE provides that the natural resources and wealth in each emirate are the public property of that emirate and that the ‘community’ must preserve and use those resources and that wealth for the public good and in the interests of the national economy.

Accordingly, subject to the constitution of the UAE, the laws of Abu Dhabi are the principal source of regulation applicable to the oil and gas industry in the emirate.

The Supreme Petroleum Council

The Supreme Petroleum Council (the SPC) is the supreme body responsible for the petroleum sector in Abu Dhabi. Upon its establishment, the SPC assumed the functions of the board of directors of ADNOC and of the former Petroleum Department of the Abu Dhabi government. Accordingly, the SPC has a number of functions:
Abu Dhabi

a the SPC formulates and oversees the implementation of Abu Dhabi’s petroleum policy and follows up its implementation across all areas of the petroleum industry to ensure that the goals it sets are accomplished;
b the SPC is expressly authorised to promulgate regulations in the petroleum field that the departments of the government of Abu Dhabi are required to implement and enforce;
c the SPC is responsible for setting the fiscal framework for the oil and gas industry in Abu Dhabi and, through its secretariat, for overseeing royalty and tax assessment and collection; and
d as noted above, the SPC issues decisions as are necessary for the management of oil companies owned by the emirate, in particular, ADNOC.6

The SPC is chaired by the ruler of Abu Dhabi and comprises nine other members, including prominent members of the ruling family, the UAE’s Minister of Energy and the current and former Chief Executive Officer of ADNOC. The SPC is supported by a full-time secretariat.

Abu Dhabi Law No. 8 of 1978 regarding the Conservation of Petroleum Resources

The principal legislation governing oil and gas operations in the emirate is Abu Dhabi Law No. 8 of 1978 regarding the Conservation of Petroleum Resources (the Conservation of Petroleum Resources Law). Although this law is drafted in general terms, it imposes high standards on the industry, in particular requiring the use of ‘the most efficient scientific techniques’ and the use of machinery and materials that conform to international standards, including as regards safety and efficiency.

The Conservation of Petroleum Resources Law covers all stages of upstream petroleum operations. The construction of facilities requires prior consent, including the submission of detailed studies and technical and economic evaluations. All exploration activity requires prior consent and any data obtained must be submitted to the SPC, together with interim and final interpretations of the data.

The law also contains detailed provisions regulating the drilling, completing, reworking and abandonment of wells, including the process for obtaining consent, minimum standards to be met and reporting obligations.

Once producing, an operator must submit monthly production reports for each producing well, including daily production rates, oil-gas ratios, wellhead pressure, sediment and water content and the API gravity of oil produced. Studies must be conducted on reservoir behaviour. Operators must also conduct ‘supplementary’ oil-recovery operations, including gas, water or steam injection if technically and economically justified to maintain production with the prior consent of the SPC and to file monthly reports in respect of those activities.

ADNOC group’s operations cover all aspects of the upstream, midstream and downstream petroleum industry, including crude oil and natural gas exploration, production, refining, processing, distribution, global marketing and the manufacture of petrochemicals.

ii Treaties

The UAE acceded to the New York Arbitration Convention on the Recognition and Enforcement of Foreign Arbitral Awards on 21 August 2006. Abu Dhabi government-owned entities typically require that agreements to which they are party, particularly if the place of performance is within the emirate, are governed by Abu Dhabi law with disputes being subject to arbitration in Abu Dhabi. The UAE has signed bilateral investment treaties with over 50 countries, including China, France, Germany, Italy, South Korea and the United Kingdom, all of whose international oil companies (IOCs) or national oil companies (NOCs) have invested in the emirate’s petroleum sector.

III LICENSING

i Crude oil

Crude oil concessions in Abu Dhabi are granted by the SPC, on behalf of the emirate. Although there is no prescribed form or model suite of oil concession agreements in Abu Dhabi, recent concessions have adopted the following structure:

\(a\) an interest in the concession in question is granted by the SPC on behalf of the emirate to IOCs or NOCs with the interest being so granted to such companies not exceeding 40 per cent in the aggregate, with the balance being held by ADNOC (or, in more recent concessions, with ADNOC having the option to hold a 60 per cent interest in the production phase of the concession);

\(b\) the concession agreement provides that participating oil companies are entitled to lift their participating interest share of crude oil produced from the concession during its term and to export that crude oil from the emirate;

\(c\) ADNOC and the other holders of concession rights sign a joint venture agreement, in which they agree to exploit the concession jointly and set out agreed governance structures (more recent concessions have dispensed with joint venture agreements);

\(d\) ADNOC and the other holders of concession rights appoint an operating company to operate the concession on their behalf on a non-profit making basis. The operating company is typically a company incorporated for this purpose by the ruler of Abu Dhabi by decree, with the operating company being exempted from the UAE Federal Law No. 2 of 2015 on Commercial Companies (the UAE Federal Commercial Companies Law). Initially, each concession area was operated by a separate operating company owned by the holders of the concession in their respective participating interests. In some of the more recent concessions, however, the SPC and ADNOC have sought greater operating and cost synergies by having one operating company operate more than one concession;\(^7\)

\(^7\) Article 4 of the UAE Federal Commercial Companies Law exempts, among others, companies in which an emirate holds at least 25 per cent of the shares and that (1) operate in oil exploration, drilling, refining, manufacturing, marketing and transportation, (2) operate in the energy sector more generally or (3) are involved in electricity generation, gas production or water desalination, transmission and distribution, if in each case a special provision to this effect is contained in the memorandum of association or articles of association of the company.
IOCs agree to maximise technology transfer to ADNOC and the operating company pursuant to master technology agreements and to provide support to them pursuant to manpower supply agreements; and

IOCs agree to support various Abu Dhabi institutions, such as the Petroleum Institute and the Masdar Institute, and to assist in the training of UAE nationals.

The SPC expects that the entity that is party to the concession agreements is the parent company of the group or that the parent company guarantees the performance of the obligations of the relevant entity.

### ii Gas

Abu Dhabi Law No. 4 of 1974 Regarding the Ownership of Gas by the Emirate of Abu Dhabi (the Gas Law) (1) vests in Abu Dhabi ownership of gas discovered or to be discovered in the emirate; and (2) grants to ADNOC the right to ‘exploit and use’ all such gas either alone or in partnership with others, so long as ADNOC’s ownership of any project is at least 51 per cent. Foreign investment in producing the emirate’s gas resources, therefore, occurs pursuant to field entry agreements with ADNOC with the joint venture being paid a fee by ADNOC for gas produced by the joint venture. Similarly foreign investment in processing and transporting the emirate’s gas resources occurs pursuant to joint ventures, with ADNOC maintaining majority ownership and the joint venture being paid a processing and transportation fee. As in the case of oil concessions, foreign partners are expected to maximise technology transfer to ADNOC and the operating company pursuant to technology support agreements, to provide support to them pursuant to manpower supply agreements and to support various Abu Dhabi institutions, such as the Petroleum Institute and the Masdar Institute, and to assist in the training of UAE nationals.

The exploitation, processing and transportation of the emirate’s gas resources remain subject to the jurisdiction of the SPC and any agreements require the prior approval of the SPC.

The Gas Law entitles oil companies operating in the emirate to use gas produced by them for their oil operations, including to generate power, to lift oil from reservoirs, to maintain reservoir pressure and as part of enhanced oil recovery operations. The Gas Law was amended in 2014 to allow ADNOC to charge oil companies for the use of such gas. Subject to the above, the Gas Law requires all oil companies operating in the emirate to deliver to ADNOC gas so produced by them.

In practice, ADNOC directs that gas be delivered to Abu Dhabi Gas Industries Ltd or GASCO, an operating company engaged in the extraction of natural gas liquids from associated and natural gas, whose shareholders are ADNOC (68 per cent), Royal Dutch Shell plc (15 per cent), Total SA (15 per cent) and Partex Gas Corporation (2 per cent).

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8 Article 2 of Abu Dhabi Law No. 4 of 1974 defines gas to include associated gas, gas within the gas cap of oil reservoirs, non-associated natural gas, including in each case methane, ethane, propane and butane and natural gasoline, pentane and condensate.
IV PRODUCTION RESTRICTIONS

The UAE has been a member of OPEC since 1967 and has a history of complying with OPEC production requirements. The UAE is represented at OPEC meetings by the UAE Federal Minister of Energy, who is invariably from Abu Dhabi and a member of the SPC.

Within the emirate, the SPC sets production targets for each field and also determines whether oil is to be exported from the Jebel Dhanna Terminal in Abu Dhabi on the coast of the Arabian Gulf or from the Fujairah Terminal, an export terminal located on the Indian Ocean in the Emirate of Fujairah. The Fujairah Terminal is linked to Abu Dhabi’s oil-producing fields by the Abu Dhabi Crude Oil Pipeline, which is capable of transporting 1.5 million barrels per day. The Abu Dhabi Crude Oil Pipeline and the Fujairah Terminal were commissioned in 2012 and are strategically important facilities that allow Abu Dhabi to export its crude oil directly to the Arabian Sea via the emirate of Fujairah, bypassing the Strait of Hormuz, thereby minimising shipping congestion through those straits and saving insurance costs, reducing journey time and allowing loading by very large crude carriers. As noted above, ADNOC has announced that it is building the world’s largest single underground project for oil storage, with a capacity of 42 million barrels of crude oil, in the emirate of Fujairah, adding to its existing storage.

V ASSIGNMENTS OF INTERESTS

The assignment of interests in oil and gas concession agreements (or the direct or indirect transfer of shares in a group company that holds interests in concession agreements) requires the prior approval of the SPC and ADNOC, unless the transfer is to a wholly owned affiliate. Any such proposed transfer would require the early involvement of the SPC and ADNOC, particularly if it is proposed that confidential information be shared with proposed transferees. In considering whether to approve any transfer, the SPC and ADNOC are likely to consider the contribution that the proposed transferee could make to the development of the concession in question and the meeting of production requirements, through the deployment of technology and human capital.

VI TAX

The fiscal regime applicable to each oil concession is determined by the SPC upon grant of the concession. Details of each such fiscal regime are not publicly available, but the fiscal regimes typically involve a mixture of royalty and income tax. The SPC is also responsible for overseeing royalty and tax assessment and collection in the emirate.

The UAE, as a member of the Gulf Co-operation Council, applies the Common Customs Law under GCC Customs Union Agreement 2003, which provides for a common 5 per cent tariff on goods imported into a Gulf Co-operation Council member state.

In 2018, value added tax was introduced by the UAE. Most costs incurred in the oil and gas industry are likely to be subject to VAT at the standard rate of 5 per cent. However both exports generally and the supply of crude oil and natural gas are zero rated, allowing VAT to be recovered in most cases.

The UAE does not levy export duties.

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9 See Article 45 of UAE Federal Law No. 8 of 2017 on Value Added Tax.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental Protection Law

Environmental protection in the UAE is principally subject to UAE Federal Law No. 24 of 1999 on the Protection and Development of the Environment (the Environmental Protection Law). The UAE Federal Environment Agency is tasked with developing, issuing and revising environmental protection standards in coordination with other relevant bodies and with establishing plans for dealing with environmental emergencies.

The Environmental Protection Law has the following objectives:

a the protection of the environment and the preservation of its quality and natural balance;

b the control of pollution and the avoiding of immediate or long-term damage or adverse impact on the environment resulting from economic development;

c the development of natural resources and the preservation of biological diversity within the UAE;

d the protection of human and animal health; and

e the implementation of the UAE’s obligations under international treaties relating to the protection of the environment, the control of pollution and the preservation of natural resources.

Title Two of the Environmental Protection Law deals with the protection of the aquatic environment – both the UAE’s coastal waters but also ground and drinking water. Article 18 prohibits the discharge of waste or polluting substances into the environment from onshore or offshore oil and gas fields unless preventative measure are in place and any discharge is treated in accordance with international practices.

Title Two of the Environmental Protection Law prohibits the discharge of oil, hazardous substances, sewage and waste into the marine environment. In the case of the discharge of oil from shipping, the owners of vessels and those operating them are liable for all expenses arising as a result of damage to the environment arising from an oil spill.

Title Three of the Environmental Protection Law deals with the protection of soil and in general terms prohibits any activity that damages the natural properties or otherwise pollutes soil, other than in accordance with implementing regulations.

Title Four of the Environmental Protection Law addresses air pollution and in particular requires that the burning of any type of fuel, including in the production of crude oil, be minimised and kept within prescribed limits. In this regard, it should be noted that the ADNOC group has adopted a no-flaring policy.

Articles 71 and 72 of the Environmental Protection Law impose a ‘polluter pays’ regime for liability. Article 71 provides that any person who intentionally or negligently causes damage to the environment or to human health as a result of the breach of the provisions of the Environmental Protection Law is responsible for all the costs of treatment or removal of such damage and is liable to pay compensation for loss incurred as a result, including compensation for loss as a result of the permanent or temporary inability to use any such polluted area, for damage to the environment’s economic and aesthetic value and for ‘rehabilitation’ costs.
Role of ADNOC Environment, Health and Safety Division

The Environmental Protection Law envisages that its licensing provisions are disappplied in the case of entities that have sufficiently robust systems and programmes to protect the environment and to achieve the purposes of the law. Accordingly the UAE and Abu Dhabi government agencies do not have jurisdiction to license the oil and gas activities conducted by ADNOC group companies or others under the authority of the SPC; ADNOC is the ‘de facto [environmental] regulatory body for the oil and gas industry in Abu Dhabi’; ADNOC is responsible for both setting standards and monitoring compliance with them.

The ADNOC HSE Code of Practice issued by ADNOC's environment, health and safety division must be complied with by all ADNOC group companies and other companies falling under the jurisdiction of the SPC. The ADNOC HSE code of practice reflects, supplements and frequently exceeds the requirements of the Environmental Protection Law. The ADNOC HSE code of practice is supplemented by HSE technical guidance that is not mandatory but the relevant operator will need to demonstrate that any departure from the technical guidance is at least as effective as the approach recommended in the ADNOC HSE technical guidance.

Decommissioning obligations are typically addressed by the relevant concession agreement or otherwise required by the SPC.

VIII FOREIGN INVESTMENT CONSIDERATIONS

Except for nationals of Gulf Cooperation Council states (including companies incorporated in such a state), legal persons may not carry out commercial activities or establish offices within the UAE except:

- by establishing a branch or representative office that requires the foreign company to have a UAE national (or a company wholly owned by UAE nationals) as its agent (often referred to as a sponsor) and by registering the branch or representative office in the foreign companies register at the Federal Ministry of Economy; or
- through a UAE-incorporated subsidiary, 51 per cent of whose shares must generally be held by one or more UAE nationals.

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10 See Article 94 of the Environmental Protection Law.
11 Article 2 of Abu Dhabi Law No. 1 of 1988 Concerning the Establishment of the Supreme Petroleum Council provides that the SPC is the supreme authority in charge of the petroleum affairs of the emirate. Article 6 of that law authorises the SPC to issue regulations; ADNOC, acting under the direction of the SPC, in turn acts as environmental regulator of the oil and gas industry in Abu Dhabi.
13 The ADNOC HSE Code of Practice and Technical Guidance must also be complied with by the few independent operators that operate in the upstream oil and gas industry in Abu Dhabi and in which ADNOC has no equity interest – principally Abu Dhabi Oil Co, Ltd (ADOC), a company jointly owned by Cosmo Energy Holdings Co, Ltd and JX Holdings, Inc that has been operating in the territorial waters of the emirate since 1967), Bunduq Oil Producing Company (a company 97 per cent owned by a Japanese consortium through United Petroleum Development Company Limited with the remaining 3 per cent held by BP) and Total Abu Al Bukhoosh or TOTAL ABK (a subsidiary of TOTAL SA). The ADNOC HSE Code of Practice and Technical Guidance are not publicly available.
14 Article 10 of the UAE Federal Commercial Companies Law requires that every company incorporated in the UAE must have one or more UAE national partners (either UAE nationals or companies wholly owned by UAE nationals) whose share in the company must not be less than 51 per cent of its share.
The SPC and ADNOC also require oil companies that participate in the upstream oil and gas sector to establish a suitably staffed office in the emirate.

To carry on commercial business in the UAE, companies are also required to obtain a commercial or trade licence from the federal and municipal authorities to carry out their proposed activities. Licences are granted to companies incorporated in the UAE, and to foreign companies operating in the UAE with a local sponsor or agent.

IX CURRENT DEVELOPMENTS

ADNOC announced in May 2019 that it is offering five major exploration blocks in a second competitive bidding round with bids due in the fourth quarter of 2019.

Finally, 2018 and 2019 saw an increased focus by ADNOC on midstream and downstream. We expect that trend to continue, and for ADNOC to increase its overseas investments and oil trading activities.
I INTRODUCTION

By area (2,381,741km²), Algeria is the largest country in Africa. The distance from the Mediterranean coast to the Hoggar massif is approximately 2000km, and 1800km from In Amenas in the East to Tindouf in the West.

The Algerian mining area is spread over an area of 1.6 million km² of sedimentary basins and is largely underexplored. This is especially true in the north and the Algerian offshore area, which both offer a significant opportunity to make new discoveries, given the significant potential. On the basis of current estimates, at the end of 2015 the established resources were estimated at 12.2 billion barrels for oil and 4.5 trillion m³ for gas. On the African continent, Algeria is classified third after Libya and Nigeria for oil resources, and second after Nigeria for gas. In addition, the Algerian mining area conceals significant resources known as non-conventional resources, relating to tight and shale reservoirs. According to the results of several geochemical modelling studies, the size of these fields falls within the 2,650 to 10,500 trillion cubic feet bracket.

Algeria’s hydrocarbon basins hold two significant shale gas and shale oil formations, the Silurian Tannezouft Shale and the Devonian Frasnian Shale. Seven of these shale gas and shale oil basins, the Ghadames (Berkine) and Illizi basins in eastern Algeria; the Timimoun, Ahnet and Maysirid basins in central Algeria; and the Reggane and Tindouf basins in southwestern Algeria, contain approximately 3,419 tcf of risked shale gas in-place, with 707 tcf as the risked, technically recoverable shale gas resource. In addition, six of these basins hold 121 billion barrels of risked shale oil and condensate in-place, with 5.7 billion barrels as the risked, technically recoverable shale oil resource.

The first major hydrocarbon discoveries in Algeria date back to the 1950s during the colonial period. The year 1956 was marked by the discovery of the two largest deposits ever made in Algeria, in gas in Hassi R’mel and in oil in Hassi Messaoud.

As early as 1963, the year following independence, Algeria set up its favoured intervention instrument in all sectors of the hydrocarbon industry, namely the national hydrocarbon company, SONATRACH.

Algeria has a very sizeable hydrocarbon transport industry that, in 2015, allowed it to transport 145.3 million TOE of hydrocarbons, broken down as follows:

- $a$ crude oil: 47.6 million tonnes;
- $b$ natural gas: 81.7 billion m³;

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1 Samy Laghouati is a partner and Djamila Annad is of counsel at Gide Loyrette Nouel.
2 BP Statistical Review of World Energy review
condensate: 9.8 million tonnes; and
LPG.: 8.3 million tonnes.

There are also three transcontinental pipelines transporting gas to Europe: connecting Algeria to Italy via Tunisia, to Spain via Morocco and through a submarine pipeline named MEDGAZ.

II LEGAL AND REGULATORY FRAMEWORK

The legal regime governing the oil activities of foreign companies in Algeria was initially subject to a concession regime implemented by the colonial authorities. Later, following hydrocarbon nationalisations by the Algerian authorities in 1971, the legal regime was amended in order to allow SONATRACH, which is the exclusive holder of mining rights, to carry out oil activities, but also setting out the framework under which the activities of foreign companies in the area of exploring for and exploiting liquid hydrocarbons is carried out. In particular:

- the creation of a partnership with SONATRACH;
- a majority holding by SONATRACH of at least 51 per cent;
- the role of operator is devolved to SONATRACH, who may entrust it to its foreign partner during the exploration phase, the risks of which are entirely taken on by the partner.

This legal framework was revised pursuant to Law No. 86-14 of 19 August 1986, which added two new forms of partnership, namely the production sharing contract (the PSC) and the risk service contract (the RSC). Law 86-14 will be amended in 1991 in order to allow foreign partners to benefit from advantages such as:

- having recourse to international arbitration to settle disputes with SONATRACH over the partnership agreement. Disputes between SONATRACH and the Algerian State remain subject to Algerian jurisdiction; and
- the foreign partner participating in the development of gas discoveries.

i Domestic oil and gas legislation

A new institutional framework regarding investments in all sectors of the hydrocarbons chain, and more specifically that of the exploration and exploitation of hydrocarbons, was implemented by Law No. 05-07 of 28 April 2005 relating to hydrocarbons, as amended by Law No. 13-01 of 20 February 2013. The most significant changes include:

- the monopoly on oil activities was withdrawn from SONATRACH and entrusted to an institution named ALNAFT, created by the law;
- the PSC and RSC forms of partnership were cancelled; and
- oil activities can only be carried out on the basis of an agreement entered into with ALNAFT, either by SONATRACH on its own, or by SONATRACH with one or more national or foreigner partner (the Contracting Party) for exploration and/or exploitation (the Agreement); SONATRACH's holding in the Agreement must be at least 51 per cent.
With the amended Law 05-07, SONATRACH loses its prerogatives as regulator and only keeps its status as operator, with specific rights and obligations compared to other operators, owing to its status as a national state-owned company.

Even though Law 05-07 expressly repeals Law 86-14, it is important to underline that the partnership agreements entered into under Law 86-14 (mostly PSCs) remain subject to the latter. However, insofar as Law 05-07 obliged SONATRACH to transfer all licences issued under Law 86-14 to ALNAFT, a parallel agreement was entered into between ALNAFT and SONATRACH in order to allow the latter to continue its activity in the context of the partnership agreement with its foreign partners.

### ii Regulation

Two regulation agencies have been set up:

- **ALNAFT** is in charge of the promotion and the management of the hydrocarbons mining area, whose powers include:
  - evaluating the capacity of an entity to carry out exploration activities; and
  - granting prospecting authorisations or hydrocarbons exploration and exploitation agreements, and ensuring their proper performance; and

- **the Hydrocarbon Regulation Authority (ARH)** is in charge of ensuring:
  - compliance with the technical regulations applicable to hydrocarbon exploration and mining activities;
  - the strict application of the principle of free access of third parties to transport infrastructures;
  - compliance with the regulations concerning hygiene, industrial and environmental security and the prevention and management of major risks – in particular the protection of groundwater and aquifers while carrying out the exploration and mining activities.

### iii Treaties

Algeria is a member of the New York Convention for the Recognition and Enforcement of Foreign Arbitral Awards (New York 1958).

Referring to the possibility provided by Article 1, Paragraph 3 of the said convention, the Democratic and Popular Republic of Algeria has declared that it will apply the said Convention, on the basis of reciprocity, to the recognition and enforcement of only arbitral awards made in the territory of another Contracting State, only when the sentences have been pronounced on disputes arising out of legal relationships, whether contractual or not, which are considered as commercial under Algerian law.

To date, Algeria has ratified:

- 40 bilateral conventions on the promotion and the protection of investments;
- 34 bilateral conventions with a view to avoiding double taxation and to prevent tax evasion in the area of income and capital tax.

### III LICENSING

The carrying out of prospecting, exploration and exploitation of hydrocarbons activities is allocated by the State to ALNAFT, which delegates for a defined area the exercise of:

- prospecting activity to any oil company through issuing a prospecting authorisation for a term of two years, renewable once for up to two years; and
b exploration and/or exploitation activities on the basis of an Agreement. The choice of the party to the Agreement is, by principle, made following a competitive tender procedure. However, the Minister for Hydrocarbons may exceptionally authorise a direct agreement provided that the derogation to the tender procedure is duly motivated. The Agreement, as well as any amending agreements, must be approved by a decree issued by the council of ministers and will enter into force on the date of the publication of the decree of approval in the Official Journal of the People’s Democratic Republic of Algeria.

i Main contractual provisions

The Agreement in particular confers upon SONATRACH and its partners the following rights:

a exclusivity for carrying out hydrocarbon exploration and exploitation works within the contractual area. In consideration thereof, the Contracting Party must undertake:
- during each of the three phases, which constitute the research period, to carry out the minimum research program contractually set out; and
- that the transition from one period to another is optional. The Agreement provides for the amount of a performance bank guarantee, at the request of ALNAFT, to cover the minimum amount of work to be performed by the Contracting Party during each research phase;

b to unilaterally declare the commercial exploitability of each discovery, and the right to keep the area covering the discovery for a period of three years for oil or humid gas deposits, and five years for dry gas deposits, in the event of the absence or limitation of transport capacities, or the recognised absence of any market for the production and sale of dry gas;

c exclusivity to exploit any discovery that has been declared commercially exploitable, provided that the development plan is approved by ALNAFT. Approval by ALNAFT, and any subsequent amendments, is equivalent to an undertaking by the Contracting Party to be bound by the development plan;

d to the ownership at the measuring point of all the production originating from the exploitation of the deposits that are the subject of the Agreement, and the ownership of all of the manufacturing facilities and assets for the contractual period. However, in the latter case, the Contracting Party is required to transfer to the state, at the end of the exploitation period, without cost or charge, the property of the said structures and facilities that must be operational and in good working condition.

However, the legislature has made it clear that the Agreement does not confer to the Contracting Party the right to the ownership of the land and to the ownership of the deposits and wells which are non-mortgage immovable properties. This provision, therefore, reaffirms the state’s right of ownership over discovered or undiscovered natural resources located on the soil or subsoil of the national territory.

The Agreement specifies:

a SONATRACH’s participation rate, which shall not be less than 51 per cent, the conditions of execution of the Agreement and the method and conditions for financing and exploitation investments; and

b the level of funding at the expense of SONATRACH, if the latter decides to participate in the financing of research investments.
A joint operating agreement signed by SONATRACH and its partners is attached to the Agreement. It mandatorily contains a marketing clause for any natural gas that may be discovered. This may be joint or for SONATRACH only, on behalf of the partnership.

ii Termination and expiry of the agreement

The law sets out the term of the Agreement based on the execution phase and the type of hydrocarbons, though early termination may be possible.

Regarding the expiry of the Agreement, the term of the Agreement varies based on the phase, which is:
- three years if no discovery has been made at the end of the first period of exploration, and if the parties decide not to continue as allowed by the Agreement;
- 37 years for conventional hydrocarbons; and
- 60 years for non-conventional hydrocarbons.

Under Law 05-07, it is possible for ALNAFT to terminate an Agreement if the Contracting Party fails to perform its obligations set out in the Agreement. Thus, the Agreement may be terminated after formal notice remains unsuccessful for 30 days from the date of its receipt by the Contracting Party upon simple notification for one of the following reasons:
- the bank guarantee provided is invalid;
- the minimum research work requirement during the research phase concerned has not been respected;
- failure to implement the development plan on time;
- the obligation to supply the domestic market has not been satisfied; and
- any taxes prescribed by law on hydrocarbons have not been paid within 30 days of the date fixed for the payment.

IV PRODUCTION RESTRICTIONS

i Restrictions on production entitlements

For reasons relating to objectives of the national energy policy, production limitations on liquid hydrocarbon deposits may be applied. These limitations are the subject of a decision of the Minister for Hydrocarbons, who sets out the quantities, the date of intervention of the limitations and their term.

ALNAFT is to allocate these limitations to all of the Contracting Parties in an equitable manner, on a pro rata basis based on their respective production.

ii Restrictions on exports of oil and gas

The quantities of gas produced in the context of an Agreement are exported on the basis of joint commercialisation with SONATRACH, or by SONATRACH on behalf of each of the parties making up the Contracting Party.

There are no export restrictions as regards liquid hydrocarbons.

iii Requirements for sales of production to local markets

Law 05-07 grants priority to meeting the needs of the national market both in liquid hydrocarbons and in gas.
As regards liquid hydrocarbons, the volumes making up these needs are distributed in an equitable manner by ALNAFT to all its contracting parties, based on their respective production levels.

The terms and conditions for the supply of the local market in liquid hydrocarbons are set out in the Agreement. The price is the FOB price published by one of the specialist reviews indicated in the Agreement.

As regards gas, ALNAFT may request each Contracting Party producing gas to contribute to meeting the national needs; the maximum rate of contribution, and the terms and conditions of supply of the local market in gas are defined in the Agreement.

The quantities of gas levied pursuant to the contribution of each Contracting Party are assigned to SONATRACH, who will then be exclusively responsible for supplying gas to the national market. SONATRACH will purchase this gas from the various producers at the average, weighted by volumes, of the prices of the various Algerian gas export sale agreements performed by the Contracting Party.

**iv Law applicable to price setting**

For the calculation of the taxation, the sale price of the liquid hydrocarbons levied in the context of the supply of the national market is the FOB price published by one of the specialised reviews indicated in the Agreement.

As regards gas intended for an export sale agreement, the basic price is the higher of the following two prices:

a. the price resulting from the agreement for the previous month; and

b. the average, weighted by volumes, of the prices of the various Algerian gas export sale agreements.

**V ASSIGNMENTS OF INTERESTS**

The transfer of all or part of the rights and obligations of a Contracting Party to an Agreement is possible, provided that it is approved by ALNAFT and implemented by an addendum to the Agreement.

SONATRACH has a pre-emption right that it can exercise within a period not exceeding 90 days from the date of notification of the transfer.

The transfer is subject to the transferor paying to the Public Treasury a non-deductible duty equal to one per cent of the value of the transaction. The method of calculating and paying this duty are specified through regulations.

Transfers between an entity and its wholly-owned subsidiaries, without involving any commercial transaction, are not subject to this provision.

**VI TAX**

From a taxation point of view, the national mining area relating to hydrocarbons for which the extraction does not necessitate a non-conventional technology is shared between four zones: A, B, C and D, to which specific taxation conditions are applied.

Taxation advantages are granted for cases such as tight or marginal fields, regardless of which zone they are in, shale oil or gas or depleted deposits requiring the use of tertiary recovery techniques.
The taxation system is composed of four levies, three of which are specific to oil activity (surface area tax, the fee and a tax on oil income), the fourth (ICR (additional income tax)) is a general law tax. Specific provisions set out the terms and conditions for the determination of the prices of the various hydrocarbons for the application of these taxes:

\( a \) the surface area tax, equal to the product of the contractual area and a price per km\(^2\), which depends on the tax zone in which the area is situated and the nature of the activity being carried out (exploration) or (exploitation). The exploitation of non-conventional hydrocarbons such as shales, requiring the use of non-conventional technologies, benefits from the lowest rates;

\( b \) the royalty, the amount of which is determined on a deposit by deposit basis. Its amount is a percentage of the value of the production from which is deducted the transport rate, which is regulated. The royalty rate, from a minimum of 5.5 per cent to a maximum of 20 per cent, depends on the level of the production and the tax area where the deposit is located. Non-conventional hydrocarbons benefit from a rate of 5 per cent whatever the level of production;

\( c \) tax on oil income, the amount of which is also determined on a deposit-by-deposit basis. The oil revenue is defined by the law on hydrocarbons. The rate is based on the profitability of the investments granted for exploiting the deposit. Its minimum varies from 10 per cent to 30 per cent and its maximum from 40 per cent to 70 per cent depending on whether the deposit is conventional, non-conventional or complex geology. It is equal to the value of the production, from which is deducted:

- the transport rate;
- the amount of royalty;
- one-fifth or one-eighth of the amount of the investments realised and relating to the said deposit uplifted of 15 per cent or 20 per cent respectively, depending on the fiscal area where the deposit is located or the non-conventional character of the hydrocarbons;
- trainings costs, provisions to cover abandonment and restoration costs; and
- the gas costs injected into the deposit in the context of the use of a specific recovery process; and

\( d \) additional income tax, applied to the consolidated profit of all of the oil activities carried out by the investor in Algeria.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Prior to carrying out any operation on the national mining area, it is mandatory to prepare an environmental impact study and a risk management plan, and to submit them to ALNAFT for approval.

At the end of the term of the Agreement, the ownership of all assets allowing the continuation of the activities is transferred to the state. ALNAFT will notify the Contracting Party of the list of facilities and assets for which the state does not require the transfer of ownership, at least three years prior to the end of the term of the Agreement.

At the time of the transfer, the assets and facilities to be transferred by the Contracting Party must be operational and in working order.

For any facility or asset for which the state does not require the transfer of ownership, the Contracting Party takes responsibility for all site abandonment or restoration costs, or both. The Contracting Party must set up provisions during the term of the Agreement in
order to meet these site abandonment or restoration costs, or both. This provision, considered as a deductible operating expense, is paid annually by the Contracting Party into an escrow account.

VIII FOREIGN INVESTMENT CONSIDERATIONS

Participation in a tender for a hydrocarbons exploration and exploitation Agreement, or for a hydrocarbons mining Agreement, is subject to obtaining a pre-qualification certificate issued by ALNAFT. A regulatory text sets out the pre-qualification rules and criteria.

It establishes two statuses necessary before an offer can be submitted:

a the status of operator-investor, requiring the technical qualifications and experience in order to act as operator and having the financial capacities required in order to meet any contractual obligations; or

b the status of non-operating investor, only requiring the financial capacities requested in order to meet any contractual obligations, but not necessarily the technical qualifications or experience required to carry out the oil operations. In this case, the company may only participate in the tender as a party to a consortium managed by a company pre-qualified as an operator-investor.

The certificate of pre-qualification will expressly set out the capacity under which the pre-qualified company can tender, namely:

a either in the capacity of an onshore operator-investor or as an onshore and offshore operator-investor; or

b in the capacity of non-operator-investor.

Once the Agreement has been allocated, the Contracting Party is obliged to provide a bank guarantee for the proper performance of the programme of exploration works, which it has undertaken to carry out.

i Establishment

Law 05-07 provides that exploration and exploitation activities may be carried out by any entity established in Algeria, or having a branch there, or organised under any other form allowing it to be a tax liable entity.

If a company is created, it has to be at least 51 per cent held by one or more Algerian resident partners, pursuant to the application of Article 66 of the Financial Law for 2016.

In practice, all foreign Contracting Party to an Agreement create an Algerian branch. The creation of such a branch does not take more than one month.

ii Capital, labour and content restrictions

In order to be able to invest in hydrocarbons exploration and exploitation, all companies have to provide evidence of their technical and financial capacities, allowing them to carry out hydrocarbons exploration and exploitation activities, and for this reason they are subject to pre-qualification according to the terms and conditions set out above.

Companies are obliged to provide a bank guarantee for the proper performance of the obligation to carry out the exploration works programme.
Strict foreign exchange controls exist in Algeria, though in order to facilitate the operations of foreign companies operating in the upstream oil sector, Law 05-07 has provided for much more flexible provisions compared to standard law rules.

According to Law 05-07, a branch is considered to be non-resident with regard to foreign exchange controls, which allows it to keep the proceeds of its hydrocarbon exports overseas, whereas a Contracting Party to an Agreement who is resident in Algeria is obliged to repatriate these amounts to Algeria.

Even though considered as non-resident, a branch is still required to import into Algeria and to transfer to the Bank of Algeria the necessary convertible currency in order to meet its exploration and development expenses and mining, pipeline transportation and operating expenses as the case may be, as well as the necessary amounts to pay the fees, taxes and duties owed.

There is no specific restriction to the upstream sector as regards the recruitment of overseas staff, it being specified that any foreigner working in Algeria must, in principle, hold a work permit. Likewise, there are no local content rules or obligations in terms of recruitment of a local workforce.

iii Anti-corruption

There are legal and regulatory provisions for the fight against corruption, undertakings are also made by the investors in the Agreements. The Agreement allocations take place in the context of an invitation to tender, which is the case for all the Agreements that have been allocated to date. Over the counter allocation is exceptional and must be justified.

IX CURRENT DEVELOPMENTS

At a regulatory level, four invitations to tender have been organised since Law 05-07 entered into force. The Algerian authorities have now admitted that the expected success of these consultations has failed to come about.

Accordingly, there are plans to enact a new hydrocarbons law replacing Law 05-07, with the main objectives of making the investment framework more attractive and others of softening the environment in which the oil operations are carried out.

On the basis of leaks of information about the draft of the new Law, it seems that the production sharing system would be adopted again after having been abrogated by Law 05-07.

We have witnessed a concentration in the upstream oil sector over the past few years between the long-standing operators in Algeria, such as ENI, Total and Repsol, who have just recently respectively recovered the Algerian upstream assets of Maersk Oil & Gas and Talisman in the context of global transactions. Total and Repsol companies, as Sonatrach partners in the exploitation of the Tin Fouyé Tabenkourt deposit under a PSC concluded in 1996, renewed their interest in this deposit by conclusion of a new contract governed by Law 05-07. Cepsa has also renewed its interest in extending the exploitation period of the R’hourde El Khourff field.

We have also witnessed the entry of new players such as investment funds, which repurchase companies holding partnership agreements (subject to Law 86-14) in Algeria, such as Carlyle and CVC, which have repurchased Engie’s Exploration-Production activity, and the Worldview capital fund, which has taken control of Petroceltic, which held a partnership agreement on the Isarène area.
Chapter 3

ARGENTINA

Pablo Alliani and Fernando Brunelli

I INTRODUCTION

Since the first oil discovery 111 years ago, the Argentine oil and gas sector worked under different rules and contractual schemes, from service contracts (1950s), risk service contracts (1970s) and agreements with YPF SE under the ‘Plan Houston’ (1980s), all of them characterised by the omnipresent role of the national state-owned company YPF SE, which owned the exploration and production rights in the hydrocarbons fields, to the ‘deregulated’ era (1990s) during which YPF SE was privatised, becoming YPF SA, existing contracts were converted into exploitation concessions and exploration permits and exploitation concessions were granted through public bidding rounds organised by the federal government.

Between 2002 and 2012, many of the basic rights permits and concessions holders enjoyed were affected by regulations and governmental practices in a context of an economy that, in general terms, became less investor- and market-friendly. Finally, in 2012 51 per cent of the shares of YPF SA were expropriated and the ‘deregulation’ regime was formally repealed.²

As result of the policies and practices implemented between 2002 and 2012, production and reserves dropped dramatically, and the country lost the hydrocarbons self-sufficiency it had achieved during the 1990s.

After the expropriation of YPF SE, the same administration that had been responsible for the policies and practices of the previous decade and for the adverse consequences derived therefrom showed a positive change of attitude towards the upstream industry, evidenced by a new pricing policy and the passing of legislation aimed at encouraging investment in new projects, especially those relating to unconventional resources.³

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1 Pablo Alliani and Fernando Brunelli are partners at Alliani & Bruzzon.
2 YPF SA was expropriated by Law 27,461 while the ‘deregulation’ decrees were repealed by Decree No. 1722/12.
3 Among others, incentive plans for the development of new gas resources (SE Resolution No. 1/13) by which a minimum price was guaranteed by the Federal Government; Decree No. 929/13, which established certain tax, exports and free availability of proceeds benefits in connection with projects involving a minimum investment amount; and Law No. 27,007, which amended the Hydrocarbons Law No. 17,319 and enhanced the benefits scheme provided for in Decree No. 929/13.
Argentina’s technically recoverable shale resources are among the largest in the world and, in recent years the industry’s attention as well as the government’s policies have been focused on the exploration and development of these resources.4

When the current administration of President Macri took office in December 2015, the development of the country’s shale resources was in a very early stage. Since then, in the context of a more investment-friendly environment and higher international prices, the exploration and development of unconventional resources has increased and seems to have gathered momentum, with several projects passing from pilot to development phase, and shale and tight sands production having become a substantial portion of the total national production, so much so that, despite the continuing decline of conventional fields, the surplus production of natural gas during the last warm season allowed the federal government to authorise exports to Chile and other countries for the first time in more than a decade.

Since April 2018, Argentina has been struggling with financial difficulties derived from a combination of international and domestic causes. This resulted in the execution of a standby facility agreement with the International Monetary Fund and a significant devaluation of the Argentine peso.

Although the situation described above impacted on certain pricing policies relating to the oil and gas sector (the government discontinued the unconventional gas subsidies programme, which remains in force in connection with already approved projects only), the production of unconventional hydrocarbons continued to grow steadily, becoming a substantial portion of the national production, as mentioned above.

General elections are scheduled for October 2019, and it is probable that Mr Alberto Fernández, the candidate of a predominantly ‘Peronista’ (populist) party opposition coalition, will prevail over the current president, Mr Macri, who is running for re-election. If that is the case, the continuing development of the country’s unconventional resources would require a clear commitment from Mr Fernández in terms of maintaining the development of these resources pursuant to the current legal framework as a strategy and long-term national policy. So far, Mr Fernández has repeatedly stated that he considers the development of Vaca Muerta a strategic and a key aspect of his government in the event he is elected President.

II LEGAL AND REGULATORY FRAMEWORK

In Argentina, the state (the federal government or the provinces, as applicable) owns the hydrocarbons in the subsoil, and the rights the state grants for the exploration and exploitation of hydrocarbon reserves are separate from surface ownership. Once extracted, the hydrocarbons belong to the companies holding the relevant exploration and production rights.

The National Constitution, as amended in 1984, provides in its Article 124 that ‘the eminent domain of the natural resources existing in their respective territories belongs to the provinces’. The provision became effective when Law 26,197, enacted in 2006, amended Law 26,197 in 2011, estimated Argentina’s technically recoverable resources of shale gas in 774 tcf, while a similar report issued by the same agency two years later increased its estimate to 831 tcf of shale gas and 30 billion bbl of shale oil, which amounts to 70 and 13 times, respectively, the present proved gas and oil reserves of the country. Argentina’s technically recoverable shale resources are the fourth and second largest in the world in connection, respectively, with oil and gas.

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17,319 (the Hydrocarbons Law) in accordance with Article 124. Therefore, as per the current Hydrocarbons Law, hydrocarbons belong to the provinces where they are located or to the nation if the resources are located in federal territory.

This means that the relevant state (nation or province) owning the resources has full authority to award rights for the exploration, development and exploitation of the resources (exploration permits, exploitation concessions and association agreements with state-owned companies) and is the enforcement authority in connection with these awards and contracts.

i Domestic oil and gas legislation

The federal Hydrocarbons Law amended, among others, by Laws 26,197 and 27,007, contains the basic material legislation in relation to the exploration, development and production of hydrocarbons.

In line with the basic rule contained in the National Constitution, the law provides that the hydrocarbons fields located in Argentine territory belong to the public domain of the national state or the provinces where the fields are located and that fields located beyond 12 nautical miles from the shoreline and until the external limit of the continental shelf belong to the federal state.

The law also sets forth, as basic principles applicable to the sector, that: (1) the federal state shall establish the general policy in relation to the exploration, exploitation, industrialisation, transport and commercialisation of hydrocarbons; (2) the holders of permits and concessions shall own the hydrocarbons extracted by them and shall be able to freely market, transport and industrialise them, subject to such regulatory provisions issued by the federal executive branch on reasonable and economic basis; and (3) during periods in which the production is insufficient to cover domestic needs, the entire availability of locally produced hydrocarbons shall be used to supply domestic demand.

The law provides for an exploration and production licences scheme, as will be explained below.

The Hydrocarbons Law is supplemented by numerous executive orders and resolutions. Other important laws are Laws No. 24,145 (federalisation of hydrocarbons), No. 26,659 (restrictions in connection with the exploration and production of petroleum in the continental shelf) and No 26,741 (establishing the achievement of petroleum self-sufficiency as a matter of national strategic interest and expropriating the controlling shares of YPF SA).

The Hydrocarbons Law coexists with hydrocarbon laws and regulations passed by certain oil and gas-producing provinces, like the Province of Neuquén Hydrocarbons Law No. 2,453, Province of Mendoza Hydrocarbons Law No. 7,526, Province of Chubut Hydrocarbons Law XVII No. 102, or Province of La Pampa Hydrocarbons Law No. 2,675, which, in general, are substantially aligned with the provisions of the Hydrocarbons Law.

ii Regulation

At a national level, the Secretariat of Energy, a subdivision within the Ministry of the Economy, is the main governmental body involved in energy regulation. The secretariat’s under-secretariat specifically devoted to oil and gas is the Under-Secretariat of Hydrocarbons and Fuels.

Each oil- and gas-producing province has its own oil and gas regulators. Provincial regulators are governed by the federal Hydrocarbons Law and by provincial legislation and regulations.
Under the Hydrocarbons Law, the national policies in respect of exploration, development, production, transportation and marketing of hydrocarbons shall be determined by the national executive branch. This means that although the provinces own the hydrocarbons, have the power to grant permits or concessions and have regulatory powers as regards the way in which the federal hydrocarbons regime is applied in their territories, the power to establish the national hydrocarbons policy and to pass material legislation remains with the federal government and Congress (as provided by the National Constitution and several federal regulations, such as the Hydrocarbons Law, Law No. 26,197 and Law No. 26,741).

iii Treaties
Argentina is a party to several conventions governing dispute resolution and recognition and enforcement of awards and judgments including, among others, the 1958 New York Convention, approved by Law No. 23,619.5

Argentina is a party to 58 bilateral foreign investment protection treaties.6

Argentina is a party to 21 double taxation treaties.7

III LICENSING
Private parties can obtain E&P rights through Superficial Inspection Permits, Exploration Permits, Exploitation Concessions and Association Agreements with state-owned companies.

i Surface inspection permits
Under a surface inspection permit, the permit holder is granted the right to conduct a surface survey on a certain area, including carrying out geologic and geophysical studies, and employing other methods, such as the drafting of plans or the performance of topographic and geodesic surveys.8

Upon the expiration of the term of the permit, the primary data obtained from the surface inspection shall be delivered to the enforcement authority, which may process the data or have it processed by third parties, and may use it as it deems convenient for its own

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5 Other conventions to which the country is a party are the Convention on the Settlement of Investment Disputes between States and Nationals of Other States; the 1991 Inter-American Convention on International Commercial Arbitration; the 1979 Montevideo Inter-American Convention on the Extraterritorial Efficacy of Foreign Judgments and Arbitral Awards; the 1940 Montevideo Convention on International Procedural Law; the MERCOSUR International Commercial Agreement; and the MERCOSUR Protocol on Jurisdictional Cooperation and Assistance Agreement in Civil, Commercial, Labour and Administrative Matters.

6 Algeria, Armenia, Australia, Austria, Belgium-Luxembourg, Bolivia, Bulgaria, Canada, Chile, China, Costa Rica, Croatia, Cuba, the Czech Republic, Denmark, Dominican Republic, Ecuador, Egypt, El Salvador, Finland, France, Germany, Greece, Guatemala, Hungary, India, Indonesia, Israel, Italy, Jamaica, Korea, Lithuania, Malaysia, Mexico, Morocco, the Netherlands, New Zealand, Nicaragua, Panama, Peru, the Philippines, Poland, Portugal, Romania, Russia, Senegal, South Africa, Spain, Sweden, Switzerland, Thailand, Tunisia, Turkey, Ukraine, the United Kingdom, the United States, Venezuela and Vietnam.

7 Australia, Austria, Belgium, Bolivia, Brazil, Canada, Chile, Denmark, Finland, France, Germany, Italy, Mexico, the Netherlands, Norway, Russia, Spain, Sweden, Switzerland, the United Arab Emirates and the United Kingdom.

8 Hydrocarbons Law, Articles 14 and 15.
purposes. During the two years following delivery, the information shall not be disclosed without the express consent of the party that performed the surface inspection, except if permits or concessions are awarded in the prospected zone.\(^9\)

### ii Exploration permits

The holder of an exploration permit has the exclusive right to perform exploratory activities within the permit area and to obtain an exploitation concession if the holder discovers oil or gas in commercially exploitable quantities and conditions (commercial discovery) during the term of its permit.\(^10\)

### iii Exploitation concessions

Exploitation concessions grant the exclusive right to exploit the existing hydrocarbon fields located in the concession area.\(^11\)

The exploitation of a field involves the development of its potential. By the same token, the exploitation concession implies for the concessionaire the ability to build and operate treatment plants as well as other facilities needed for the operations, including having the right to request a transportation concession for the transportation of the production out of the concession area.

The hydrocarbons shall belong to the concessionaire in accordance with its participating interest in the concession, and the concessionaire shall be able to dispose of its share of the production freely, subject to the general limitations contained in the Hydrocarbons Law and its supplementary regulations.

### iv Association agreements with province-owned companies

Typically, in these agreements the province-owned company is the owner of the exploration and production rights and makes such rights available to the joint venture with the private party or parties.

Usually, the province-owned company holds a 10 per cent participating interest.

The private parties assume all the exploratory risk on an exclusive basis. In some agreements, the private parties are allowed to recover these costs from the province-owned company upon a commercial discovery and the entry into the exploitation stage by applying a certain percentage (usually 50 per cent) of the provincial company's entitlement to the...
production. Upon the occurrence of a commercial discovery and the subsequent grant of an exploitation concession on the block, the province-owned company must pay its share of capital and operating expenditures (CAPEX and OPEX).12

The hydrocarbons shall belong to each party in accordance with its participating interest in the contract and each party shall be able to dispose of its share of the production freely, subject to the general limitations contained in the Hydrocarbons Law and its supplementary regulations.

The private party (or one of the private parties if there is more than one) shall be the operator.

The association agreements are awarded, within the framework of a public bidding process called by the executive branch of the relevant province, by the province-owned company, and the award requires the approval by the province.

v Processes by which licences are awarded
Surface inspection permits are granted by the relevant governmental authority upon a request made by a company willing to conduct the surface inspection.

Exploration permits are granted through public bidding rounds. The criteria to award the blocks are based on the work units’ commitment made by the bidder and, in some bids, on the entry fee offered by the bidder. The public tender will be awarded to the bidder proposing the highest offer, in accordance with a formula that considers the aspects mentioned above.

Exploitation concessions can be obtained: (1) by the holder of an exploration permit, upon the occurrence of a commercial discovery, over all or a portion of the exploration area; (2) through a public bidding round in connection with ‘proved’ blocks (blocks where exploration activities are deemed unnecessary); or (3) in the case of unconventional exploitation concessions, by the holder of an exploitation concession that, based on the unconventional potential of the block, asks for a subdivision of the concession area and for the grant of an unconventional concession on the subdivided area with unconventional potential.

Association agreements with state-owned companies are granted through public bidding rounds.

vi Key terms for licences
As per the Hydrocarbons Law, the exploration periods shall be set forth in the terms and conditions applicable to each public bid, within the following maximum terms.

For a permit with a conventional objective, there is a basic term of three years plus three years, plus an extension term of five years. In permits referring to offshore exploration, each of the periods of the basic term can be increased by one year.

For a permit with an unconventional objective, the basic term is four years plus four years, plus an extension term of five years.

12 The agreements executed by Gas y Petróleo del Neuquén SA – the Province of Neuquén-owned company – provide that, upon the grant of an exploitation concession, the provincial company may opt between keeping its participating interest in the production and CAPEX and OPEX expenditures, or assign the participating interest to the private parties and receive a 2.5 per cent overriding royalty on the production from the concession area.
At the end of the first period of the basic term, the permit holder shall be able to keep all the exploration area, while at the end of the second period of the basic term, the exploration area shall be relinquished, unless an extension is requested, in which case at least 50 per cent of the area shall be relinquished.

The term of exploitation concessions is 25 years (30 years for offshore concessions). The term of unconventional exploitation concessions is 35 years.

Concessions can be renewed for 10-year periods, and there is no limit on the number of renewals, which must be requested not less than one year before the expiry of the current term and can be requested by concessionaires that are in compliance with their obligations under the relevant concession. Extensions are not granted automatically but require governmental approval so, in practice, some negotiation is required.

vii Revocation and expiry of licences

Permits and concessions will be revoked for the following reasons: (1) failure to pay any annual surface fee within three months of becoming due; (2) failure to pay royalties within three months of becoming due; (3) substantial and unjustified failure to comply with specified obligations with respect to productivity, conservation, investment, works or special benefits; (4) repeated infringement of the duty to submit information, to facilitate inspections by the enforcement authority or to use adequate techniques for the execution of the works; (5) failure to comply with the obligations provided in Articles 22 and 33 of the Hydrocarbons Law; (6) bankruptcy of the permit or concession holder; (7) death of the individual or dissolution of the legal entity holding the permit or concession. Before declaring the revocation owing to any of the aforementioned causes, the enforcement authority shall serve notice to the permit or concession holders requiring them to remedy the infringement within the term stated in the notice.

Permits and concessions will expire upon the lapse of their terms or upon relinquishment by the holder. In case of partial relinquishment, the permit or concession will expire in respect of the relinquished area only.

viii Government take

Royalties on the production of hydrocarbons must be paid every month to the relevant province or to the national government.

The Hydrocarbons Law provides for a 12 per cent royalty on the net price obtained from the sale of hydrocarbons produced under exploitation concessions and a 15 per cent royalty on the net sales of hydrocarbons produced under exploration permits.

Royalties can be reduced by up to 50 per cent in tertiary production (enhanced oil recovery and improved oil recovery), extra heavy oil and offshore projects that, owing to their particular productivity issues and location, present especially unfavourable technical and economic characteristics.

13 Article 33 provides for the obligation of the permit holder to declare commerciality within a certain term after the occurrence of a commercial discovery. Article 33 refers to the size of each exploitation lot and certain concessionaire’s obligations in this respect.
14 Article 80 of Hydrocarbons Law.
15 Hydrocarbons Law, Article 81 HL.
16 Royalty is regulated by Articles 59 to 65 of the Hydrocarbons Law and by Decree No. 1,671/1969.
17 Hydrocarbons Law, Article 27 ter (introduced by Law No. 27,007).
During the extension periods of concessions, an additional royalty of up to 3 per cent can be added, with an 18 per cent total cap.

The royalty provided in the law shall be the only government take calculated on the production.\(^{18}\)

The Hydrocarbons Law establishes that the holders of exploration permits and concessions must pay a fixed yearly fee (payable in advance in January), which is calculated by each square kilometre of the permit or concession area. During the exploration phase, these yearly fees vary depending on the exploration period, as explained below.

Law No. 27,007 allows for an extension bonus to be charged when a concession extension is granted. The maximum bonus shall be equal to the figure resulting from multiplying the proved reserves remaining at the end of the term of the concession by 2 per cent of the average price in the relevant basin for the two-year period prior to the granting of the extension.

\section*{IV PRODUCTION RESTRICTIONS}

Licence holders own and have the free availability of their share of the petroleum substances produced from the relevant area, subject to the general limitations established in the applicable regulations, basically to secure adequate supply of the domestic market.\(^{19}\)

In line with the aforementioned, the production of crude oil exports has to be offered to the domestic market first.

Governmental authorisation is required for any gas exports.\(^{20}\) Owing to the surplus production during the last warm season (October to April), the Ministry of Energy and Mining authorised several exports of natural gas for the first time in a decade, under interruptible supply terms, without applying any reimport requirements.\(^{21}\)

Market prices apply for crude oil, taking Brent as a reference and applying certain discounts thereon.

As regards natural gas prices, there is a mix of regulated and market prices.

The Ministry of Energy Resolution No. 46/17, as amended by Resolutions No. 419/17 and 12/18, established a subsidies programme to stimulate investments for the development of production of natural gas from unconventional reservoirs in the Neuquén Basin. Pursuant to this scheme, a guaranteed minimum price of US$7.50/MMBtu applied during 2018, and, thereafter, it will decrease US$0.50 per year until it reaches US$6/MMBtu in 2021. On 31 December 2021, the programme will end and prices should match import parity values. The difference between the minimum guaranteed prices and the actual market prices

\(^{18}\) However, in concessions that were extended before the enactment of Law No. 27,007 (2014), extra payments on the production may apply, such as additional payments of up to 3 per cent of the production, and certain windfall profit payments apply, which are triggered when the prices obtained for the hydrocarbons produced from the concession area exceed certain parameters.

\(^{19}\) Hydrocarbons Law, Article 6.

\(^{20}\) Law No. 24,076 and Secretariat of Energy Resolution No. 104/18 (passed on 21 August 2018) which, subject to the authority's authorisation, allows seasonal, long- and short-term firm and interruptible exports and exports required to deal with emergency situations with a subsequent obligation to reimport the same volumes that were exported

\(^{21}\) These were exports of natural gas to Chile, Uruguay and Brazil by companies such as YPF, Total, Pan American Energy, Pampa Energía, Wintershall and Exxonmobil.

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will be paid to the producers by the federal government. A few projects qualified for this subsidy before the government announced that no more projects would be approved under this scheme earlier this year.

Ministry of Energy Resolution 212E/2016 established a scheme for a gradual increase in the price of natural gas not included in the incentive programme mentioned above that began in 2016 and will end in 2019 when domestic prices would converge with import parity prices. However, the government intends that by the end of 2019 all gas prices (except for gas produced from projects that have already qualified for a subsidised price programme) be subject to market prices. In line with this, Ministry of Energy Resolution No. 46/18, issued in 2018, provides that gas for power generation shall be acquired through tender processes to be conducted by CAMMESA (the company that administers the wholesale electricity market).

V ASSIGNMENTS OF INTERESTS

According to Article 72 of the Hydrocarbons Law, participating interests in permits and concessions can be assigned, with the prior authorisation of the executive branch (federal or provincial, as applicable), in favour of those that fulfil the financial and technical conditions and requirements needed to be a permit holder or concessionaire.

Under Article 73 of the Hydrocarbons Law, a concessionaire can assign its interest in an Exploitation Concession as a security interest in respect of loans obtained to finance the upstream operations in the relevant concession area.

Provincial hydrocarbon laws contain provisions in line with the ones described above.

The change of control of the company holding the licence does not require governmental authorisation.

The federal state and most of the provinces do not have any rights of first refusal upon the assignment of participating interests in permits or concessions submitted to the relevant authorities for their authorisation.22

The transfer of any upstream licence is subject to the rules of Argentine Antitrust Law No. 27,442, and, therefore, approval by the antitrust regulator might be required, depending on the specific circumstances of each transaction.

Usually assignment authorisations can be obtained within 60 or 90 days of the request and the information required being submitted.

VI TAX

Within the national jurisdiction, in accordance with the relevant provisions and as long as they are applicable, upstream companies will be liable for the payment of all federal taxes generally applicable in the country (income tax, value added tax, debits and credits in bank accounts tax) and any applicable customs duties.

They shall also be liable for the payment of all provincial (gross income tax and stamp tax) and municipal taxes in force as of the date of the award. During the term of duration of the permits and concessions, the provinces and municipalities shall not levy new taxes upon

22 As an exception, Decree No. 348/15 of the Province of Río Negro provides that the province will have a right to match the commercial terms of the intended assignment and acquire the participation once assignment authorisation has been requested.
the holders thereof, nor increase the rate of preexistent taxes, except for those rates paid in consideration for the performance of services and as contributions for improvements, or a general increase of taxes. 23

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental laws and environmental regulators

Pursuant to Article 41 of the National Constitution, legislative powers are transferred by the provinces in favour of the federal state for the issuance of basic rules of general application in environmental matters.

Following this criterion, at the national level the hydrocarbons sector is governed by: (1) general regulations containing minimum environmental protection standards, such as Law No. 25,675 (the General Environmental Law) and Law No. 24,501 (the Hazardous Waste Law); and (2) general regulations and minimum standards specifically applicable to hydrocarbon activities issued by the enforcement authority while exercising the powers delegated by the Hydrocarbons Law to that effect. For a long time, this authority was held by the Secretariat of Energy. Other regulations could also be issued by the Secretariat of the Environment and Sustainable Development.

The main applicable regulations include:

a policies and procedures for the protection of the environment: Resolution SE No. 105/92 (1) requires the submission of a prior environmental study before drilling the first exploratory well and commencing development of the reserves, (2) provides for the implementation of an annual monitoring of works and tasks and (3) sets out in detail technical guidelines to be followed in the exploration and exploitation of hydrocarbons;

b annual environmental monitoring reports: Resolution SE No. 25/04 defines and describes the technical characteristics, structure and scope of environmental studies and annual environmental monitoring reports. The environmental studies include four phases: an initial environmental status; an identification and characterisation of environmental effects and prioritisation of environmental impacts; an environmental impact mitigation plan; and a monitoring plan;

c contingency plans and information about incidents: If an environmental incident occurs, contingency plans must meet the guidelines provided under Resolution SE No. 342/93 and the enforcement authority must be informed within the deadlines and satisfying the requirements established by Resolution SE No. 24/04;

d emission (i.e., venting) of gas to the atmosphere: Resolution SE No. 143/98 establishes guidelines and mandatory limits on this matter and the exceptions, under certain justified circumstances, authorised to exceed these limits;

e safety conditions and maintenance of storage tanks of crude oil and by-products: Decree No. 10877/60 describes the active and passive defences to be implemented in the facilities. Resolution SE No. 785/05 created the Programme for the Control of Spills from Surface Storage Tanks, which established that companies that have these facilities have to register and inspect the tanks. Companies must also comply with a maintenance plan, report any incidents and report the abandonment of the tanks;

23 Hydrocarbons Law, Article 56(a).
f safety auditing service: Resolution SE No. 419/93 and other supplementary regulations provide for the refineries’, storage companies’ and operators of service stations’ obligation to hire safety auditing services to certify, on an annual basis, compliance with the applicable safety regulations; and

g provincial regulations: The provinces are empowered to supplement the federal regulations with local regulations, provided they do not overstep the established principle of federal law preeminence. In this regard, provincial regulations have been passed in connection with several environmental matters, such as a gaseous emissions control regime, subterranean water exploitation regime, groundwater exploitation regime and pressurised devices control regime.

ii Environmental approvals necessary for oil and gas operations

An environmental study must be prepared prior to the development of a new project and submitted to the relevant (provincial or national) environmental enforcement authority. Upon the approval of the study, the operation can begin and the operator shall comply with recommendations, restrictions and conditions (if any) contained in such approval (Resolution SE No. 105/92 and related regulations).

Additionally, the operator will have to (1) obtain an authorisation for the use of water in the project, which shall include the origin of the water and the conditions under which it shall be used, and (2) register with the National Hazardous Waste Generators Registry and the issuance of the Annual Environmental Certificate (Law No. 24,051, Decree No. 831/93 and other regulations).

iii Legal requirements with respect to decommissioning

Resolution No. 5/96 issued by the former Secretariat of Energy established rules and procedures for the abandonment of oil and gas wells, including a timetable for the abandonment of certain wells. On an annual basis the operator shall report the decommissioning works performed in the past year and those to be performed in the following year. Four years before the expiration of the respective concessions, or as from the date of relinquishment of all or part of an exploitation block, the concessionaire must submit a technical and economic study explaining the reasons why the abandonment of each inactive well could be inconvenient. Recommended techniques for performing definitive abandonment are detailed in the same resolution. The technical conditions applicable to the abandonment of gas pipelines and ancillary facilities are established in resolutions NAG 100 and NAG 153 of Enargas. The abandonment of these facilities requires the prior consent of Enargas, which will evaluate whether there is a general interest in keeping the facilities operative.

There is no requirement to constitute a fund to pay any costs associated with the abandonment of wells and facilities.

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24 National Constitution, Article 3.
25 Enargas is the national gas regulator.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
There are no foreign investment approvals or restrictions in relation to investment in petroleum.

Foreign investors wishing to hold an interest in an upstream licence will have to (1) register a branch of a foreign company with the Public Registry of Commerce; or (2) set up a local company (usually a sociedad anónima (stock company), a sociedad anónima unipersonal (stock company with a sole shareholder) or a sociedad de responsabilidad limitada (limited liability company). To act as a shareholder or quota holder of an Argentine company, a foreign company must register with the Public Registry of Commerce with the sole purpose of being a shareholder or quota holder of a local company.

In the City of Buenos Aires, registering a branch may take between 30 and 45 days, while establishing a local company may take between 60 and 90 days, including the registration of the foreign companies that will be the shareholders and the incorporation of the new company.

A branch is not a separate entity from the foreign company that has registered it. A sociedad anónima, a sociedad anónima unipersonal and a sociedad de responsabilidad limitada are separate entities from their shareholders or quotaholders who limit their responsibility to the integration of their respective capital contributions.

From an administrative point of view, branches are quite simple structures as the only requirement is to have a legal representative, while companies require the appointment of a board of directors or managers. Two-thirds of the members of the board must be Argentine residents.

ii Capital, labour and content restrictions

Capital restrictions
Currently no restrictions apply on the movement of capital or access to foreign exchange. Declared dividends as well as the profits of a branch can be freely repatriated. There are no restrictions either in connection repayments of loans to external creditors.

Local content requirements applicable to oil and gas operations
The Hydrocarbons Law provides that those performing works it regulates shall prefer to hire nationals and, particularly, residents of the region where the works shall be performed, and that the proportion of nationals employed by each concessionaire or permit holder shall not be less than 75 per cent. In practice, exceptions to the above-mentioned rule are accepted in connection with specialist workers that are not available in Argentina or in the region where operations are conducted.

Similar provisions can be found in provincial laws and regulations, as well as in the terms and conditions applicable to bidding rounds organised by the provinces.

Also, there are certain provincial regulations establishing an obligation to favour the hiring of services from local suppliers.

26 General Companies Law No. 19,550, Article 118.
27 General Companies Law No. 19,550, Article 123.
28 Hydrocarbons Law, Article 71.
29 Like Neuquén Law No. 3032, which contains an obligation to acquire certain percentages a minimum of 60 per cent of the contractual amount from companies based in Neuquén, which is calculated on an
Restrictions on the ability to hire foreign workers
There are no restrictions to hire foreign workers, provided that the applicable immigration regulations are complied with.\textsuperscript{30}

iii Anti-corruption
The following is a summary of the anticorruption regulations.

Public Ethics Law No 25,188 and its regulatory Decree No. 164/1999
Public Ethics Law No 25,188 and its regulatory Decree No. 164/1999 set forth the duties, prohibitions and incompatibilities applicable to all public officers and establish, among other duties and prohibitions, that public officers shall: (1) strictly abide by the National Constitution and the laws; (2) act honestly, diligently and in good faith; (3) act in the public interest; (4) not obtain or receive any personal benefit related to the performance, the delay in performing or the omission to perform any act inherent to their functions; (5) use public property only for authorised purposes related to the performance of their duties and shall not use or allow any third party to use any information obtained in connection with their public functions in the benefit of private interests; and (6) observe, in any public bidding process, the equality, publicity, free competition and reasonability principles.

The Anti-Corruption Agency, answerable to the Ministry of Justice and Human Rights, is the Authority of Application of Law No. 25,188 and is responsible for preparing and coordinating anti-corruption policies as well as investigating corruption cases. The agency also keeps public officers’ assets disclosure records and provides a whistle-blower mechanism on its website.

Argentine Criminal Code
Bribery of foreign or local public officers is prohibited and penalised in Article 258(b) of the Argentine Criminal Code (ACC).

Article 258(b) punishes with prison any person who offers or gives to a public officer from a foreign state or from an international public organisation, personally or through an intermediary, money or any object of pecuniary value or other gifts, promises or benefits, for their own benefit or for the benefit of a third party, for the purpose of having the officer perform or not perform an action related to their function or to use the influence derived from the office they hold in an economic, financial or commercial transaction.

Articles 256 to 259, on the other hand, punish both the citizen who bribes an Argentine public officer and the public officer who receives the bribe. The punishment is increased when the public officer is a judge, prosecutor or any other person related to the administration of justice.

\textsuperscript{30} Immigration Law No. 25,871, its Regulatory Decree No. 616/2010 and supplementary dispositions enacted by the enforcement authority, the National Immigration Directorate.
Article 256(b) of the ACC sets forth provisions regarding ‘improper lobbying’. This article states that anyone who requests or receives money or any other gift or accepts a promise of such to exert unlawful influence on a public official will be punished.

**Criminal liability of legal entities**

Law No. 27,401, enacted in late 2017, provides the criminal liability of private legal entities in connection with the offences contemplated in Articles 258 and 258 bis described above, Article 265 (negotiations that are not compatible with the exercise of public functions), Article 268 (extortion) and Article 300 bis (false or fraudulent financial statements) of the Criminal Code.

The sanctions provided by the law include fines, suspension of activities and dissolution. The company may receive a reduced fine, and it may even be released from any criminal liability if it self-reports an offence provided for in the law, of which it has become aware as result of proper internal controls implemented before the occurrence of the wrongdoing that is being reported, and provided it returns the unlawful benefit obtained.

**Anti-corruption conventions**

Argentina has signed – without reserves – the following anticorruption conventions:

a. the Inter-American Convention against Corruption (IACAC) 1996;

b. the Convention for Combating Bribery of Foreign Officers in International Business Transactions (OECD Anti-Bribery Convention) 1997;

c. the United Nations Conventions against Business Corruption 2003; and


**IX CURRENT DEVELOPMENTS**

With 11 blocks already undergoing massive development, Vaca Muerta continues to be at the centre of the industry’s and government’s attention.

The increase in the production of unconventional hydrocarbons contributed to improve the total oil production as well as the total gas production, even when the existing conventional fields continued to decline. In June 2019, the national oil production amounted to 500,000 bbl/d, 4 per cent more than the previous year, while the natural gas production amounted to 140 million m³/d, 5.8 per cent more than the previous year. This was the largest production of natural gas in the country since 2009.31

This situation, which if it continues as expected, might lead the country’s energy trade balance to show a positive figure between 2020 and 2021,32 has allowed Argentina to resume natural gas exports to its neighbours, especially Chile, for the first time in more than a decade, all of them approved in accordance with former Ministry of Energy’s Resolution No. 104/18 (issued on 21 August 2018) described above, by companies such as YPF, Total, Pan American Energy, Pampa Energía, Wintershall and Exxonmobil.33

31 Source: Secretariat of Energy.

32 The last time Argentina showed a positive energy trade balance was in 2011.

33 The expansion of the natural gas production was boosted by, among other things, the prolific Fortín de Piedra project, the largest unconventional gas-producing block, where Tepetrol is executing a US$2.3 billion investment plan.
The growing surplus natural gas production during the warm season, and eventually throughout the year, requires that new infrastructure and export alternatives be made available in the near to mid-term future, such as new pipelines and facilities that will enable the country to carry out LNG exports to Asia and other overseas markets, which will require substantial investment in infrastructure (transportation, liquefaction facilities, shipping facilities, etc.) as well as a more production and transportation cost-effective structure.

In this respect, the federal government has launched a public tender for the construction and operation of a new gas pipeline from the Vaca Muerta area in the Province of Neuquén to Saliqueló, in the south of the Province of Buenos Aires. The first stage, of 57km, should be completed by mid-2021. Other projects, whose implementation has not begun yet or that are still undergoing an early evaluation stage, are the ‘Vaca Muerta Train’, a 700km railway for the transportation of supplies and materials from the city of Bahía Blanca, in the Province of Buenos Aires, to Añelo, in the Province of Neuquén, and a construction of a liquefaction facility in Bahía Blanca.

In the crude oil transportation department, Executive Order 115/19 (which amended Executive Order 44/91), passed earlier this year, empowered the Secretariat of Energy to launch public bidding processes for the grant of one or more liquid hydrocarbons transportation concessions. The Executive Order also provides that, in order to facilitate the financing of new petroleum transportation projects, the developer of a new pipeline, as well as an existing concessionaire willing to expand its transportation facilities, may sell and reserve firm capacity in advance, at transportation tariffs to be freely negotiated with the transporters willing to secure transportation capacity in the new facilities.

Last, the first offshore bidding round was launched during the last quarter of 2018 (Executive Order 872/18 and SE Resolution 65/18) and bids were received on 16 April 2019. Of the 38 blocks offered in three offshore basins, 18 were awarded to 13 companies. The total work commitments amounted to approximately US$700 million. The formal grant of the exploration permits to the winning bidders is expected for late August or early September 2019.

The large basins in Argentina’s continental shelf are mostly unexplored, except for a few natural gas-producing shallow waters blocks in the Austral Marina Basin near the Tierra del Fuego and Santa Cruz provinces. The grant of exploration permits under this bidding round will be a great opportunity to acquire valuable information that will allow the companies involved, and the country, to have a better knowledge of the actual potential of the basins and to eventually develop the resources that may be discovered.

The general elections scheduled for October this year, in which there is a significant chance that the ‘Peronista’ party candidate, Mr Alberto Fernández, may prevail over the current President, Mr Macri, and former Minister of the Economy Mr Roberto Lavagna, together with the financial difficulties the country has been going through since last year, may delay certain investment announcements and projects. However, all of the above-mentioned candidates have stressed that the complete development of the country’s hydrocarbons resources, especially Vaca Muerta, will continue to be a strategic and a key aspect in the country’s energy policy for years to come.

34 Blocks were awarded to Equinor, YPF, Qatar Oil, Shell, Total, BP, Exxon, Pluspetrol, Wintershall, Tullow, Eni, Mitsui and Tecpetrol.
I INTRODUCTION

With a land area of 83,879km² and a population of approximately 8.9 million, Austria is the 14th largest country in terms of land area and the 15th largest in terms of population in the European Union, constituting 1.7 per cent of the population of the European Union.

According to Statistik Austria, gross domestic natural gas consumption in 2017 was 325,899TJ, whereby domestic production was 43,665TJ and total gas imported amounted to 481,712TJ. Austria relies heavily on oil and gas imports, primarily from the Russian Federation.

Despite being a net importer of oil and gas, Austria has a respectable domestic upstream gas sector, with key fields in the Vienna Basin in Lower Austria and the Molasse Basin in Upper Austria and Salzburg.

The Austrian upstream sector is dominated by two companies, OMV (formerly Österreichische Mineralölverwaltung AG), a partly federal state-owned company responsible for approximately 88 per cent of crude oil and natural gas liquids produced, and Rohöl-Aufsuchungs AG (RAG), a privately owned company responsible for approximately 12 per cent of oil and 14.5 per cent of gas.

In addition to its upstream sector activities, Austria plays a central role in the European midstream natural gas sector, with the Central European Gas Hub at Baumgarten an der March being the main transit point for imported Russian gas to Western Europe.

Beyond domestic production, OMV is heavily involved in the international upstream sector, with operations in, inter alia, the North Sea, Tunisia, New Zealand, Romania and Yemen. OMV is the operator of Austria’s only refinery in Schwechat. In addition to its upstream activities, RAG focuses on drilling technology and on large-scale gas storage, boasting a storage capacity of approximately 5.9bcm, 70 per cent of the Austrian annual gas demand.

This chapter will focus on Austrian domestic oil and gas exploration and production, and where appropriate shall provide the German language legislative act name or term in italics for reference.
II LEGAL AND REGULATORY FRAMEWORK

Due to its size and administrative structure, Austrian energy legislation is fairly comprehensive with one central act regulating oil and gas exploration and production as well as general mining activities on the federal state (Bund) level, with the enactment of certain minor pieces of legislation being delegated the relevant ministry or to the state governments.

The administrative role is again very centralised, with Section VI of the Federal Ministry for Sustainability and Tourism (the Ministry) responsible for the performance of a great deal of administrative duties in the upstream sector.

It must be noted that given the greater development and importance of the mid- and downstream sectors in Austria, a greater amount of legislation has been enacted and further administrative bodies are involved in these sectors in comparison to the upstream sector.

i Domestic oil and gas legislation

The central legislative act for the exploration and production of oil and gas is the Mineral Resources Act 1999 (MRA),3 applicable to the entire federal state.

Due to its membership in the European Union, Austria has implemented a number of directives that apply to the upstream energy sector. The Oil and Gas Licencing Directive,4 which aims to ensure non-discriminate access to oil and gas exploration and production, was implemented in Austria under the Federal Procurement Act 2006.5

The Stocks of Crude Oil and Petroleum Products Directive,6 intended to address the issue of European Union energy security, was implemented by the Oil Stockholding Act 2012,7 the Energy Steering Act 2012,8 the Oil Statistics Regulation 20119 and the Gas Statistics Regulation 2012.10

On the basis of these key acts, a number of regulations have been issued detailing specific provisions, such as accident management and waste disposal, which shall be introduced below.

ii Regulation

As described above, the Ministry plays a very central role in the Austrian upstream sector. The Ministry derives its powers from the Mineral Resources Act, as well as other relevant legislation as expanded upon below. It is primarily responsible for the development of national oil and gas policy, and it authorises and manages the exploration and production on behalf of the federal state.

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7 Federal Law Gazette I No. 78/2012.
10 Federal Law Gazette II No. 475/2012.
iii Treaties

As a Member State of the European Union, Austria is part of the internal market for gas,\textsuperscript{11} having implemented the European Third Energy Package, as well as the Energy Union, both of which aim to liberalise the European natural gas market. In addition to the above-mentioned European directives, the reporting provisions of the Regulation on Wholesale Energy Market Integrity and Transparency (REMIT)\textsuperscript{12} have direct effect on Austrian gas market participants, as detailed below.

Austria is a signatory to the Energy Charter Treaty, which aims to facilitate the trade of energy between the signatory states, which include major players such as the European Union and its Member States, the Russian Federation, Ukraine and Australia. The Energy Charter Treaty provides specifically for non-discriminatory trading rules for energy, reliable cross-border transit flows, the protection of direct foreign investment, the promotion of energy efficiency, and an international dispute resolution scheme between participating states and between investors and host states.

Austria has entered into several bilateral agreements on energy matters, the energy matters, including with both the Czech Republic\textsuperscript{13} and Slovakia\textsuperscript{14} regarding cooperation in oil and gas exploration.

III LICENSING

i Right to explore and produce

Oil and gas are considered property of the federal state pursuant to Section 4(1)(2) of the Mineral Resources Act, and the federal state has the right to explore for and produce oil and gas.

It may alternatively transfer the exercise of this right in specific exploration areas for a specific duration to individuals, companies, or commercial law partnerships, provided that these possess the necessary technical capabilities and financial resources.

Pursuant to Section 178 of the Federal Procurement Act, as rights owner for the exploration and production of oil and gas on the federal territory, the federal state must transfer these rights in accordance with the fundamental freedoms of the European Union, the principle of non-discrimination, the principles of free and fair competition, and the equal treatment of bidders for the rights.

The Mineral Resources Act additionally makes provision for the exploration for geological structures in which gas may be stored underground.

Instead of the transfer of rights being done by means of a licensing regime or a production-sharing agreement, a civil law contract is concluded between the Ministry in agreement with the Federal Ministry for Finance, in return for an ‘appropriate’ consideration.

This consideration comprises either an ‘area interest’ for exploration or a ‘field interest’ and ‘production interest’ for production (including the right to acquire the oil or gas produced) for the duration of the transfer. Pursuant to Section 69(1) of the Mineral Resources Act, this consideration may, however, be suspended when deemed necessary to:

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\textsuperscript{12}Regulation (EU) No. 1227/2011 on wholesale energy market integrity and transparency.
(1) avert a macroeconomic imbalance; (2) avert a deterioration in the competitive structure of the mining rights holder; (3) avert a deterioration of the security of supply of the market with state-owned mineral resources; (4) improve the utilisation of resources by federal mineral resources; or (5) protect other economically important concerns.

From a practical perspective, primarily OMV and RAG are involved in the exploration and production of oil and gas in the Austrian Federal territory, whereby the federal state has 31.5 per cent ownership of OMV through the Austrian State Holding Company (Österreichische Beteiligungs AG (ÖBAG)).

### ii  Work programme

A key condition of exploration and production of oil and gas by both the federal state and any rights holder is the submission of a work programme for approval by the Ministry in accordance with Sections 71 and 72 of the Mineral Resources Act.

The work programme must include details on the nature, extent and aim of the proposed work, its chronological order, the proposed plant, the planned safety systems and measures to restore the land use upon decommissioning, and the name of the responsible person. Any material changes made to an approved work programme, specifically the performance of work other than that previously declared or the use of different means, must be approved by the Ministry.

An exploration report must be submitted to the Ministry at the end of each calendar year, which contains details on the outcomes of the exploration.

### iii  Further approvals

Pursuant to Section 119 of the Mineral Resources Act, any drilling project or probe that exceeds a depth of over 300 metres requires approval by the Ministry. Following application, a consultation period will begin, whereby the site will undergo inspection and the concerns of any neighbours to the site will be taken into account.

The drilling approval may be time-limited, and can only be issued when the following criteria have been fulfilled: (1) the affected land owners have agreed to the plans, or if not possible, the issuance of an expropriation court order issued in accordance with Sections 148 to 150 of the Mineral Resources Act; (2) the use of state-of-the-art measures to prevent avoidable emissions; (3) the use of measures to ensure that subject to current medical science, no harm will come to the health or lives of individuals and that no unreasonable nuisance will be caused to individuals; (4) the use of measures to ensure that no unreasonable levels of harm to the environment or water will be caused by waste products; (5) the use of measures to ensure that if possible, any waste is prevented or recycled, and that other waste will be properly disposed of in a commercially reasonable manner; and (6) the use of measures to ensure that any air pollution complies with the relevant state regulation in accordance with Section 10 of the Air Pollution Control Act 1997.15

As the transfer of exploration and production rights is governed by a civil law contract, and with no draft publicly available, it is difficult to establish any standardised key terms beyond what is prescribed by legislation.

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iv Registration and reporting obligations

Of relevance to gas producers, REMIT entered into force on 28 December 2011, with the aim of increasing the stability and transparency of the European wholesale energy markets, as well as tackling market manipulation and insider trading.

By virtue of the direct effect, Austrian gas producers (but notably not oil producers), defined by REMIT as market participants who enter into contracts for the sale of wholesale energy products on the wholesale energy market, are subject to a number of reporting obligations.

Pursuant to Article 4(1) of REMIT, Austrian gas producers are obliged to publish information to the Agency for the Cooperation of Energy Regulations (ACER)\(^\text{16}\) on the capacity and use of their production facilities, as well as any planned or unplanned unavailability.

Pursuant to Article 8(1) of REMIT, Austrian gas producers are further obliged to submit information on: (1) gas sold; (2) the price and quantity; (3) the dates and times of execution; (4) the parties to the transaction; (5) the beneficiaries of the transaction; and (6) any other relevant information. Gas producers subject to this Article 8(1) obligation must furthermore register with the Austrian national regulatory authority,\(^\text{17}\) Energie-Control Austria, in short, E-Control.\(^\text{18}\)

In accordance with Section 11(2)(1) of the Gas Statistics Regulation 2012, the gas production plant operator must register itself with E-Control.

IV PRODUCTION RESTRICTIONS

As described above, Austria has implemented the Stocks of Crude Oil and Petroleum Products Directive into a number of national acts and regulations.

The aim of the Directive and, therefore, of these acts and regulations is to mitigate an energy supply crisis in the European Union by maintaining a minimum stock level, maintaining information on these stock levels and ensuring the accessibility and availability of the stocks.

Oil producers as well as oil importers are required by Section 3 of the Oil Statistics Regulation to submit monthly oil production data and oil import data respectively to the Ministry.

Gas producers are required to submit a monthly report on the physical imports and exports of gas through pipelines that make up part of their production facilities pursuant to Section 5(2) of the Gas Statistics Regulation, as well as on the total monthly production volume and own consumption as per each production plant pursuant to Section 5(4). Furthermore, gas producers must submit the maximum production rate, detailed information on and a graphic of the plant pipelines, and the technical maximum capacity per injection and feed out point per border station on an annual basis, pursuant to Section 7(2). E-Control publishes the submitted data from all market participants subject to reporting obligations on an annual basis.


\(^{18}\) As established by the Energie-Control-Gesetz (Federal Law Gazette I No. 110/2010).
Imports and exports of oil are regulated by the Oil Stockholding Act. While the importation of oil is highly regulated, whereby all import activities must be reported to the Ministry, there is no regulation and, therefore, under normal circumstances, no restrictions of oil exports from the Austrian market into the markets of EU Member States.

Should there be a direct threat to the Austrian energy supply, however, the federal state is permitted to block all energy exports (both oil and gas) in accordance with Section 18 in conjunction with Section 4 of the Energy Steering Act, to be done by means of a regulation enacted by the Ministry.

V  ASSIGNMENTS OF INTERESTS

As described in Section III, the exploration and production of oil and gas with the Austrian federal territory is governed by a civil law contract. Provisions relating to assignments of interest, right of first refusal or preferential purchase rights upon transfer, and consideration as a condition to granting approval to transfer or waiving rights of first refusal may be included; however, as no draft contract is publicly available, it is difficult to determine whether these terms have been considered.

VI  TAX

i  Corporate income tax

In most cases companies engaging in oil and gas exploration will have the legal form of a limited liability company or stock company. These legal entities are considered corporations within the meaning of Section 1 Corporate Income Tax Act 1988, as amended, and subject to corporate income tax.

According to Section 7 of the Corporate Income Tax Act, the tax base for the corporate income tax is the yearly income of the corporation. The starting point for the calculation of the taxable income is the profit according to the external accounting under the provisions of the Austrian Commercial Code. In the course of the calculation of the taxable income, the profit according to the external accounting is adapted with increases and reductions to meet the requirements of the provisions of the tax law. These adaptions can, for instance, be required for the depreciation or valuation of assets, the consideration of non-deductible expenses, etc.

The taxable income of the corporation is subject to corporate income tax at a rate of 25 per cent. Under the provision of Section 8 of the Corporate Income Tax Act, losses from previous years may be used to set off the taxable profit in the amount of a maximum of 75 per cent of the tax base of the current year.

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20 German Empire Law Gazette (Deutsches Reichsgesetzblatt) S 219/1897 as amended by Federal Law Gazette I No. 120/2005.

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ii Value added tax

Corporations trading in oil and gas are considered entrepreneurs within the meaning of Section 2 of the Value Added Tax Act 1994. The provisions of supplies or services in the exchange for a consideration performed in Austria by such entrepreneurs in general are subject to value added tax.

Under the provision of Section 10 of the Value Added Tax Act, the applicable value added tax rate in Austria is 20 per cent of the consideration. As regarding the sales of oil and gas produced upstream, pursuant to Section 10(1) of the Value Added Tax Act, oil is subject to a 20 per cent VAT rate, whereas pursuant to Section 10(2)(4)(c), gas is subject to a 10 per cent VAT rate. It is important to note that depending on downstream processing, individual oil- and gas-derived end products may have different VAT rates from the upstream products.

iii Mineral oil tax

The mineral oil tax is a consumption tax. According to Section 1 of the Mineral Oil Tax Act 1995, mineral oil that is produced or imported to Austria as well as motor fuels and heating fuels is subject to mineral oil tax in Austria. Most hydrocarbon-containing products are covered by this law.

Section 3 of the Mineral Oil Tax Act includes a detailed list of the applicable tax rates for most sorts of taxable products. All products not included in this list are subject to tax, with the tax rate applicable to a product on the list that comes closest to the product not included.

The tax liability for mineral oils in general arises if the taxable product is released into free circulation (i.e., by the removal from a tax warehouse). Special provisions apply to motor and heating fuels. For these fuels, the tax liability arises once they are first delivered for their intended purpose.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In accordance with the Environmental Impact Assessment Act 2000, operations involving the production of oil and gas must undergo an environmental impact assessment by the Ministry if their production exceeds certain thresholds. Pursuant to point 27 of Annex 1 of the Environmental Impact Assessment Act, these thresholds are either when the production of oil exceeds 500toe/day per probe or when the production of gas exceeds 500,000m³/day per probe. A simplified assessment procedure is to be performed if production is carried out in protected areas either when the production of oil exceeds 250toe/day per probe or when the production of gas exceeds 250,000m³/day per probe.

In addition to the above listed criteria and approvals, rights holders must present the Ministry with a ‘waste disposal plan’ two weeks prior to commencement of operations at the latest in accordance with Section 117a of the Mineral Resources Act. This must be reviewed every five years, and should the activity have materially changed, amended appropriately. The

The aim of this waste disposal plan is to reduce or avoid waste and any damaging effects, as well as to establish short- and long-term disposal of waste as a result of exploration and production activities.

As described in Section III, prior to exploration and production, the rights holder must provide information on measures to restore the land usage upon decommissioning. Decommissioning of exploration and production equipment is specifically regulated in Section 119(14) of the Mineral Resources Act, whereby unless the rights holder has previously submitted a ‘closure plan’ including information on the intended conveyance of property, the person in possession of the plant must notify the Ministry.

If submitted, a closure plan must be submitted to the Ministry for approval pursuant to Section 144 of the Mineral Resources Act. This must include: (1) a precise description of the closure procedure including safety measures; (2) a description of measures to ensure the safety of individuals and property during decommissioning; (3) a description of planned measures to restore land usage; (4) information regarding the conveyance or alternative of any remaining property; (5) the main geological and deposit-mineralogical documentation and documentation regarding the production activities performed by the rights holder; and (6) a list of existing production operations or a map of underground operations.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Undertakings with their seat within the European Economic Area (EEA) (including European Union Member States) or Switzerland are not bound by any limitations in investing in the Austrian oil and gas upstream market.

Undertakings with their seat in a third country (i.e., a non-EEA country or Switzerland) are subject to the Foreign Trade and Payments Act 2011. Section 25a(2)(2) in conjunction with Section 25a(3)(2)(a) of the Foreign Trade and Payments Act provides that those wishing to (1) take over, (2) invest in (only when acquiring over 25 per cent of the company’s voting rights), or (3) acquire a controlling majority in companies that are involved in energy supply require approval by the Ministry.

Should an investor from a third county aim to circumvent this rule through use of an undertaking with seat in the EEA or Switzerland, the Ministry may, in certain circumstances, conduct a review to ensure the above provision is enforced.

ii Capital, labour and content restrictions

Capital and labour from EEA countries or Switzerland into Austria is not and must not be limited by virtue of the European Union fundamental freedoms of capital and labour.

Austrian employers of workers posted from third countries – and by extension employers with seat in EEA member countries or Switzerland – must apply to the Public Employment Service for either a ‘posting permit’ for workers posted up to four months, or an ‘employment permit’ for periods lasting over four months.

In any case, a visa is required for posts of less than six months, and for those with posts exceeding six months a ‘posted worker stay permit’ is required. In order to receive this, in

accordance with Section 59 of the Settlement and Residence Act 2005\textsuperscript{25} the worker must fulfil the criteria listed in Part 1 of the Act, and provide confirmation of guaranteed work in accordance with Section 11 of the Employment of Foreign Nationals Act 1975\textsuperscript{26} or an employment permit as a posted worker.

iii Anti-corruption

The Federal Bureau of Anti-Corruption (FBAC) is responsible for security and police matters regarding corruption for the entire federal state. The FBAC has been given its powers under the Law of the Federal Bureau of Anti-Corruption.\textsuperscript{27}

Anti-corruption measures are primarily regulated in Sections 302 to 313 of the Austrian Criminal Code,\textsuperscript{28} whereby such corruptive practices are generally punished by imprisonment between six months to a maximum of 10 years, depending on the financial value of the advantage gained.

There are currently no significant anti-corruption issues in the Austrian upstream energy sector.

IX CURRENT DEVELOPMENTS

In 2015, the Austrian Energy Efficiency Act (AEEA)\textsuperscript{29} came into force in Austria. Its aim is to increase energy efficiency by 20 per cent by 2020 through the promotion of the use of renewables and the reduction of greenhouse gas emissions.

According to the new legislation, large corporations (the threshold is having over 250 employees or an annual turnover of at least €50 million) are required to either conduct an energy audit at least once every four years or install a certified energy management system in accordance with ISO standards.

The Austrian Energy Agency has been appointed as national monitoring body responsible for the assessment of these audits or implementation of energy management systems. Upstream oil and gas market participants may fall under the obligations under the AEEA if they fulfil the criteria of ‘large corporations’. While the legislation does not provide any further obligations for these companies beyond energy suppliers, it is important to implement either of these systems.

Due to the complexity and cumbersome nature of these new rules, especially for energy suppliers, the new legislation is prone to induce additional cost and administrative burdens for energy suppliers and companies conducting business in the energy sector in Austria.

In the winter months from December 2017 to March 2019, OMV performed a significant survey on an area covering 1,500km\textsuperscript{2} in the Weinviertel, in Lower Austria, to a depth of between 4,000 and 6,000m, generating data in the amount of 700 terabytes. According to the company, it was the biggest three-dimensional seismic survey of its kind performed in Europe. In doing so, OMV has increased its investment in the region by €30 million to approximately €90 million. On the basis of the collected data and its ongoing comprehensive analysis, a three-dimensional image is currently being created, which will

\textsuperscript{25} Federal Law Gazette I No. 100/2005 as amended by Federal Law Gazette I No. 70/2015.
\textsuperscript{26} Federal Law Gazette No. 218/1975.
\textsuperscript{28} Federal Law Gazette No. 60/1974.
\textsuperscript{29} Federal Law Gazette I No. 72/2014.
enable OMV to further investigate potential gas reserves in the region. These oil and gas fields are expected to produce for at least another 15 to 20 years, and are expected to ensure OMV’s national production rates at its 2015 rate of 32,000 barrels per day.

OMV’s newest venture, known as ‘Altlichtenwarth Tief 1’ is a 16-week-long exploration well in the Weinviertel to a depth of approximately 4,000km. This is scheduled to commence in Autumn 2019. OMV hopes to discover oil and gas reserves amounting to millions of barrels; however, as of the date of writing, no further details have been disclosed.
Chapter 5

BRAZIL

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I INTRODUCTION

In 2018, the Brazilian oil and gas industry grew stronger on the back of a continued offer and interest for pre-salt assets. Despite a marginal decrease in current production, Brazil recorded a substantial growth in revenue from government participations and signature bonuses. A reasonable rise in proven reserves was enough to keep Brazil in the 15th global position. With respect to natural gas, Brazil stayed in the 32nd place in the global ranking, with 570 billion cubic metres in proven reserves.

Helped by the upward trend in oil prices (around 30 per cent up in comparison with 2017’s average spot prices), the level of activity in the industry is picking up as the regulator managed to complete three bid rounds with positive results. During 2018, The Brazilian National Oil, Natural Gas and Biofuels Agency (ANP) conducted the 15th concession bid round and the fourth and fifth production sharing (pre-salt) rounds. In these instances, a total of US$2 billion in signature bonuses were paid, signalling a further investment of US$300 million in minimum work programmes. Together with the fourth and fifth bid rounds for pre-salt acreage, the revenue from signature bonuses totalled US$4.5 billion and more than US$700 million committed with exploratory work.

According to the latest report issued by the regulator ANP, in 2018, (1) oil production decreased to 2,683,000 bbl/d, which is a marginal drop from previous year, but still above the annual results for the past decade; (2) 1.4 billions of barrels were added to the proven reserves calculation, which represent a 5 per cent increase from the previous year; (3) royalties and special participation revenues climbed to approximately US$5.9 billion (53 per cent above 2017 levels) and to US$7.4 billion (96 per cent above 2017 levels), respectively.

Key regulatory steps were taken in order to create a balanced and predictable environment and boost investors’ appetite for Brazilian acreage. One of these steps was to publish a multiple-year bid round plan, which include the ongoing 16th round for concession assets and the 6th round for pre-salt areas for 2019. Furthermore, 2019 will also see the auction for the Excess Rights in connection with the onerous assignment made to Petrobras by means of Law 12,276/2010. In 2019, ANP also started the first cycle of ‘permanent offer’ (sometimes referred to as ‘open acreage’) to attract investment to mature areas.

Brazil is clearly becoming a major global oil destination, with an increased commitment for the development of giant fields located in ultra-deep water in the pre-salt layer. The reason is a combination of reduced development costs and high productivity (sometimes over 50,000...
barrels a day). The pre-salt fields have, however, a very high quantity of associated natural gas, which need to be sold to the market or reinjected. Reinjection is happening on a large scale today, but sometimes it cannot be used for technical reasons, and in other situations it may reduce the amount of oil that could be extracted from the reservoir over its economic life.

Thus, the federal government has been devoting itself to revising the legislation applicable to natural gas to facilitate investment in the construction of a new infrastructure necessary for the offloading of natural gas from pre-salt fields. In addition, it is taking steps to end Petrobras’ de facto monopoly on the sale of natural gas in Brazil, with the expectation that this will facilitate the sale of natural gas produced by other companies, creating a more dynamic market for the locally produced and competitively priced associated natural gas from pre-salt fields.

In late 2018, the new president, Jair Bolsonaro, who has a much more liberal economic agenda than previous governments, was elected. This new agenda seeks to facilitate the entry of private companies in the oil and natural gas sector in Brazil as a way of accelerating the development of pre-salt fields. The new federal government has been accelerating Petrobras’ divestment process as a way of obtaining funds to be invested in the development of pre-salt fields. In this divestment programme, there are several mature fields located onshore. This is attracting several smaller companies to the oil sector, many of which are controlled by local entrepreneurs, which tends to completely change the prospect of this industry in Brazil, until now concentrated only on large international companies.

II LEGAL AND REGULATORY FRAMEWORK

The Brazilian oil and gas sector is regulated by general provisions of the Brazilian Constitution, as well as by a number of different federal laws, and ordinances and resolutions enacted by ANP.

Pursuant to Articles 20 and 176 of the Brazilian Constitution, oil and gas reserves located in Brazilian territory (including continental shelf, territorial sea and exclusive economic areas) are considered assets of the federal government. However, once they are produced in accordance with applicable laws, the property of these resources is vested in the person that holds the extraction rights.

After the enactment of Constitutional Amendment No. 09/1995, the federal government’s monopoly over exploration and production of oil and gas reserves was loosened, allowing the federal government to contract state-owned or private companies.

Domestic oil and gas legislation

The Constitution gave the federal government monopoly over several activities related to oil and gas. Constitutional Amendment No. 9/95 allowed these activities to also be performed by private companies.

Thus, with the end of Petrobras’ monopoly over the oil industry, Law No. 9,478/97, which governs the new legal framework for the oil industry (the Oil Law), was approved. It created the National Council for Energy Policy (CNPE), chaired by the Minister of Mines and Energy (MME), with the duty to prepare energy policies and guidelines, and ANP, the entity in charge of regulation, engagement and inspection of the oil, gas, and biofuels industry’s economic activities, and responsible for, among other duties, preparing the bidding proceedings for the concession of rights of oil and gas exploration and production, executing the concession agreements and inspecting their performance.
In 2008, a discussion to modify the Oil Law regarding ‘midstream’ gas activities was initiated, resulting in the enactment of Law No. 11,909/09 (the Gas Law), whose regulation was approved by Decree No. 7,382/10. The Gas Law is currently under revision, as part of the ‘Gas to Grow’ programme launched by the federal government to diagnose all the problems in the industry and propose solutions to stimulate its development (Bill No. 6,407/13).

In 2010, Law No. 12,276/2010 was created, authorising the federal government to assign to Petrobras the exploration and production rights over an area where the existence of at least 5 billion barrels of oil and gas was estimated (this area was converted into four production fields named Atapu, Sépia, Búzios and Itapu). Such rights were granted to Petrobras in exchange of new shares issued by that company and subscribed by the federal government in accordance with a contract also known as the onerous assignment agreement (OAA). In accordance with Law No. 12,276/2010, Petrobras is not allowed to assign any working interest in the fields subject to this law.

Law No. 12,351/2010 was also enacted in 2010, and established the production sharing legal regime for the exploration and production of oil in a given geographically demarcated area under the terms of this law, which became known as the pre-salt polygon. The rest of the territory – around 98 per cent of the total area of the Brazilian sedimentary basins – is still subject to the concession regime established by the Oil Law.

Originally, Petrobras had to be the operator in any consortia (unincorporated joint ventures) that acquired areas within the pre-salt polygon and had to hold an ownership interest of at least 30 per cent in these consortia. Law No. 13,365/2016 made these rules more flexible, and, today, Petrobras only has a right of first refusal for acquiring an interest of up to 30 per cent in the consortia, as an operator. According to the relevant law, Petrobras must indicate the areas in relation to which it intends to exercise its right in advance, so that the companies participating in the bid for the acquisition of these areas know beforehand when they will be subject to Petrobras’ right of first refusal.

Since in areas subject to the production sharing regime, a part of the production belongs to the federal government, Law No. 12,304/2010 created government-owned company Pre-Sal Petróleo SA (PPSA), with the purpose of representing the federal government in the consortia operating under this regime.

In summary, in terms of oil and gas exploration and production, Brazil has three legal regimes: (1) the concession regime created by Law No. 9,478/97 that is the ‘general rule’ in Brazil; (2) the onerous assignment regime created by Law No. 12,276/2010 that is applicable to certain fields (Atapu, Sépia, Búzios and Itapu) and up to 5 billion barrels of oil and gas; and (3) the production sharing regime created by Law No. 12,351/2010 that is applicable to reservoirs located inside the pre-salt polygon. In any situation, a specific agreement will be entered into with ANP.

It is important to note that certain activities involving natural gas (transportation, storage, trading, etc.) are governed by the Gas Law. The main goal of this law was to turn natural gas transportation through pipelines into a public service. Consequently, the construction and operation of natural gas pipelines become subject to a concession agreement that must be granted through a public tender organised by ANP. However, Bill No. 6,407/13, which is under discussion in the Congress, aims at carrying out a profound modification in the legal regime applicable to those activities. The objective of the bill is to simplify the legal regime applicable to those activities.

Oil and gas exploration and production activities must also comply with environmental laws and regulations created by the national environmental agency (IBAMA).
ii Regulation
MME is mainly responsible for planning the use of oil and natural gas. MME, after consulting with ANP, proposes to CNPE the definition of the areas that will be subject to concession agreement or production sharing agreement (PSA) regime, and the technical and economic parameters for the PSA. MME also approves the drafts of the bid documents and the PSA prepared by ANP.

CNPE has the main purpose of fostering the rational use of the nation’s energy resources, ensuring the proper functioning of the national fuels inventory system, reviewing energy matrixes for different regions of Brazil and establishing guidelines. It is responsible for authorising ANP to offer blocks under the concession regime and the PSA regime.

ANP is the national regulator of the oil, gas and biofuels industry, and is in charge of regulating, contracting and supervising economic activities related to the oil, natural gas and biofuels industry, as well as establishing technical standards for various related activities. ANP is also responsible for supervising compliance with safety standards and its regulations.

IBAMA is responsible for environmental regulations regarding upstream offshore activities. For onshore activities, other state and local environmental agencies may also have the power to regulate upstream activities.

The Brazilian Maritime Transportation Agency (ANTAQ) is responsible for regulating and supervising the maritime transportation of oil as well as maritime support activities. Only Brazilian navigation companies, duly authorised by ANTAQ and ANP, may perform maritime transportation and support activities within the country.

The Brazilian Navy has multiple roles in offshore exploration and production. In addition to technical inspection and entry control for any vessel or platform, it has jurisdiction over any incidents that take place on Brazilian waters. It is also responsible for maintaining the registry of maritime property, such as vessels.

iii Treaties
The demarcation of the Brazilian continental shelf was established in accordance with the United Nations Convention on the Law of the Sea, executed on 10 December 1982. This convention is of great importance since the definition of areas where mineral resources may be exploited by Brazil, notably oil and natural gas, depend on it.

Therefore, it was a major milestone for the Brazilian upstream industry when an authorisation from the Commission on Limits of the Continental Shelf to extend the national continental shelf boundaries to 350 nautical miles from the southern coastline came forth. This important diplomatic and economic achievement was concluded in 2019, at the 50th plenary session, allowing Brazil to exploit natural resources in this new region, which is 150 nautical miles wider than the standard 200-mile limit.

The process of extending the outer limit of Brazilian Continental Shelf was claimed to the United Nations (UN) in 2004, after 17 years of studies, conducted and promoted by ANP, the Brazilian Geological Service and the Navy, which found evidence of not only oil reserves, but also of other minerals such as cobalt and manganese.

Experts estimate that the exploration of this maritime area could increase the volume of oil and gas reserves in Brazil, today estimated at 15.9 billion barrels, by 50 per cent. In the extended range of the continental shelf near the pre-salt, seismic studies have indicated that the structures may contain total reserves between 20 billion and 30 billion oil barrels.

In respect to tax treaties, and for the purpose of avoiding double taxation, Brazil has entered into tax treaties with the countries listed below. These treaties executed by Brazil and
its partners usually follow the Model Tax Convention of the Organisation for Economic Co-operation and Development (OECD) even though Brazil is not an OECD member. Brazil has entered into treaties with Argentina, Austria, Belgium, Canada, Chile, China, the Czech Republic, Denmark, Ecuador, Finland, France, Holland, Hungary, India, Israel, Italy, Japan, Korea, Luxembourg, Mexico, Norway, Peru, the Philippines, Portugal, Slovakia, South Africa, Spain, Sweden and Ukraine.

Brazil has ratified the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention) through Decree 4,311/2002. However, Brazil does not have significant bilateral investment agreements in force. In relation to tax information exchange agreements (TIEAs), Brazil has enacted Decree 8,003 of 15 May 2013, which put into effect a TIEA executed with the United States.

### III LICENSING

Since the end of Petrobras’s monopoly in the 1990s and prior to the approval of the Pre-Salt Law, the only regime applicable for the granting of exploration and production rights in Brazil was the concession regime. At the end of 2010, the PSA regime was established to govern exploration and production on pre-salt areas and areas deemed strategic by the federal government.

Thus, there are two different regulatory frameworks for the granting of exploration and production rights in Brazil (from the licensing point of view, the onerous assignment regime is not relevant). Under the concession regime (similar to a tax-royalty regime), the granting of concession contracts for exploration and production activities is preceded by a tender (known as bid rounds). The tender documents must establish all technical, financial and legal criteria and requirements that a bidder must comply with in order to be qualified for the bidding round as a non-operator or operator A, B or C. In general terms, the ‘non-operator’ is a capital partner; operator A is the company qualified by the ANP to operate in any block offered in the bid; while operators B and C are eligible to operate in some restricted blocks to be defined by the agency (usually in shallow waters and onshore, respectively).

Companies may submit bidding offers individually or jointly in consortium. For a consortium, a qualified operator among them shall be indicated.

The criteria for the evaluation of bidding offers are:

- signature bonus: a lump sum payable in a single instalment upon execution of the concession agreement or PSA; and
- minimum work programme.

There is no restriction on foreign participation, provided that the foreign investor incorporates a company under the Brazilian law and complies with all technical, legal and financial requirements established by the ANP before the execution of the concession agreement (or the PSA). Companies of the same corporate group are prevented from making competing offers for the same block. Under the PSA regime, a portion of the oil and gas production is paid to the oil and gas companies as reimbursement for their exploration and production costs (known as cost oil), and the federal government shares the remaining production (known as profit oil) with the relevant oil and gas companies according to the ratio set forth in the respective PSAs.

Recently, a new law ended Petrobras’ mandatory operation and minimum stakes in the pre-salt area. Now, Petrobras only has preferential rights for the operation and minimum
stakes in each pre-salt area to be offered in a bid round; and with respect to those areas in which Petrobras does not exercise its preferential rights, any company may be the operator, provided that the company qualifies as an operator A.

PPSA is a 100 per cent state-owned company created to represent the federal government in the consortium and is responsible for the management of the PSAs. PPSA cannot perform upstream oil and gas activities and will not make investments, but has very important responsibilities, including managing and supervising PSAs and representing the government in the operating committees. PPSA is entitled to appoint half of the members of the operating committee, including the chairperson.

The only criterion used to determine the winning bidders is the percentage of profit oil to be given to the government. Signature bonus under the PSA regime has a fixed value, as well as the minimum work programme and the local content. The special participation and payment for area occupation or retention, both part of the government take in the concession regime, are not applicable under the PSA regime.

The winners of the bid (individually or in a consortium) will bear 100 per cent of the exploration and production costs, but will receive a share of the profit oil as payment and will have the right to reimbursement of the cost oil (oil and natural gas equivalent to exploration and production costs), subject to payment of the applicable government take.

In both regimes, companies are required to comply with local content commitments as well as mandatory investment in research and development (R&D).

IV PRODUCTION RESTRICTIONS

Although the concessionaires or contractors under the PSA are entitled to explore and produce oil and natural gas, property of hydrocarbons in situ, as in most jurisdictions, is vested in the government.

Concessionaires have ownership over the entire volume of the oil and natural gas produced under the concession regime, where the volumetric measurement of the oil and natural gas produced is made according to the ANP’s regulations. For blocks within the scope of the Pre-Salt Law, the ownership is transferred to the oil company at the production sharing point, where the production is shared between the government and contractors.

Oil and gas are freely exportable in Brazil and there are no limits or quotas applicable to oil and gas production. Nevertheless, the export company must be authorised by ANP to perform these activities. The exporting and importing companies must present reports and information to ANP on each sale.

Furthermore, the exportation of any goods, including oil and its by-products, must necessarily be recorded in the national integrated system for international commerce, SISCOMEX, which is an online platform that enables the government to control international trade by establishing a one-way flow of information. Requirements of the maritime authorities (ANTAQ and the Navy), the tax authorities (the Federal Revenue Secretariat and the state tax secretariats) and the Brazilian Central Bank (currency exchange regulation) will also apply. All current import and export authorisations are governed by the recent ANP Resolution 777 of 5 April 2019, which revoked a large number of previously edited regulations by the ANP.

Notwithstanding the foregoing, in emergency situations in which the domestic supply of oil and natural gas is impaired or threatened (which must be declared by the Brazilian president), ANP may limit the export of hydrocarbons, as well as of its by-products, after giving 30 days’ prior notice to the companies. The portion of the production on which the
restriction applies will be determined on a monthly basis considering the participation of the company in the national oil and gas production in the immediately preceding month. So far, Brazil has not faced this situation.

There is no specific requirement applicable to the sale of oil in local markets, only to its by-products. The overall taxation regime applies for oil and natural gas sales in the local market. Some quality requirements must be observed by companies selling natural gas.

Prices for oil and gas are freely stipulated between the parties according to the market price. However, ANP establishes the minimum oil price to be considered by the agency for the calculation of government takes or eventual cost oil.

Anticompetitive practices in connection with the exploration, production, transportation, refining or marketing of crude oil or crude oil products are subject to the scrutiny of the Brazilian Antitrust Authority (CADE), and may subject companies to penalties.

V ASSIGNMENTS OF INTERESTS

Generally, any assignment of interests will require ANP’s prior authorisation. The rationale only applies to direct transfers, as ANP recently changed its understanding and no longer evaluates indirect transfers (such as mergers).

Only Brazilian companies that meet ANP’s requirements for technical, legal and financial qualifications are entitled to acquire participating interest in both the concession regime and the PSA regime.

No fees are required and no preferential purchase rights upon transfer are reserved for the government, either in the concession regime or in the PSA regime. ANP takes, on average, four to six months to approve an assignment request.

ANP is currently reviewing its assignment procedure, and several changes are likely to be implemented in the upcoming months – for example, ANP intends to change the effective date of the assignment.

In addition to ANP’s approval, CADE’s clearance may also be required if the groups involved in the transaction meet the following revenues threshold as set forth in the Brazilian antitrust laws: (1) at least one of the groups involved (seller or buyer) registered gross revenues in Brazil in excess of 750 million reais, during the fiscal year immediately prior to the transaction; and (2) at least one of the other groups involved registered gross revenues in Brazil in excess of 75 million reais, during the fiscal year immediately prior to the transaction.

In order to obtain CADE’s approval, the payment of a 45,000 reais fee is required. The transfer of licence rights for oil and gas exploration and production to third parties is generally analysed by CADE under the fast-track procedure. Thus, CADE usually takes between 30 and 45 days to approve such a transaction.

CADE’s approval is required by ANP as a condition for ANP’s approval.

VI TAX

The oil and gas industry is usually taxed at the same rates for indirect (IPI, ICMS, ISS, customs duties, CIDE) and direct taxes (IRPJ, CSLL, PIS and COFINS) applicable to most Brazilian companies.

REPETRO is a special customs regime for the industry that allows the suspension of federal import taxes (i.e., customs duties, excise tax and PIS/COFINS on imports), or
Brazilian federal import taxes, on the importation of goods intended for the exploration and production of oil and gas by certain eligible entities. Recently, the federal government extended the REPETRO regime until 2040.

REPETRO only applies to those goods listed by the Brazilian tax authorities. The entities that may be eligible to use REPETRO for the importation of eligible goods are: (1) the beneficiary of a concession or permit to carry out oil and gas research, or exploration and production activities in Brazil; and (2) those entities hired by the concessionaire under charter agreements, or to render services related to the performance of the activities involved in the concession or permit, as well as their subcontracted entities.

The following special customs treatments are available under REPETRO:

a) symbolic exportation regime: full suspension of Brazilian federal import taxes on symbolic exportation of the benefited goods without actual removal of the goods from the Brazilian customs territory (goods manufactured by a Brazilian industry and sold to a foreign entity that does not physically remove the goods from the country) and subsequent importation under the temporary admission regime in item (c) below;

b) special drawback regime: full suspension of Brazilian federal import taxes levied on the raw materials, semi-industrialised or finished products, parts and pieces to be used in the manufacture of an asset that will be imported under the symbolic exportation regime; and

c) temporary admission regime: full suspension of Brazilian federal import taxes levied on certain goods of foreign origin that were actually imported on a temporary basis, for a fixed period of time. After the period of temporary admission, the goods must, among other options, be re-exported, destroyed, transferred to another special customs regime, or dispatched for consumption in Brazil (in the case of dispatch for consumption, the full payment of Brazilian federal import taxes will be required).

The terms and conditions for REPETRO’s application are currently detailed by Normative Instruction No. 1,781/2017, issued by the Federal Revenue Secretariat, which has undergone a major change by Normative Instructions No. 1,880/2019 and 1,901/2019. Among the main modifications are the restrictions created for the temporary importation of platforms and vessels employed in oil and natural gas production (including FPSOs). If owned by a company linked to the concessionaire that operates the oil field, these platforms and vessels must be permanently imported, even with the suspension of all federal taxes (on state tax (VAT), see the following paragraph). This rule eliminates a tax saving that could be achieved by reducing the profit that would be taxed by income tax in Brazil, which compromises the economic feasibility of low-profit fields.

At the state level, VAT benefits may also be available depending on the legislation of each state. CONFAZ Agreement No. 03/2018 has authorised Brazilian states to:

a) reduce the ICMS tax base so that the final tax burden corresponds to 3 per cent on the importation or domestic acquisition of permanent goods or assets applied in the exploration and production of oil and natural gas, without appropriation of the corresponding credit;

b) exempt the ICMS levied on the importation of temporary goods or assets for engagement in the exploration and production of oil and natural gas defined by Law 9,478/97, within the scope of REPETRO;

c) exempt the ICMS levied on export operations of temporary or permanent goods and assets manufactured in the country that are admitted or acquired under the terms of the
previous items, even without them leaving the national territory, or for sale to a person based in the country, inside or outside the state where the manufacturer is located, as well as previous operations, which are all goods and assets supply operations performed by the suppliers and respective sub-suppliers of the national manufacturers of goods or assets employed in the oil and natural gas exploration and production activities.

Law No. 11,196/2005 establishes tax benefits for the oil and gas industry, among other provisions. The benefits covered include exemption of corporate taxes (IRPJ, CSLL) and IPI. However, Law No. 11,196 also requires companies to meet certain requirements to be eligible for the benefits, especially with regard to mandatory investment in R&D.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Article 225 of the Brazilian Constitution classifies the environment as a common usage asset and imposes on public authorities and on the community the duty to protect and defend it for present and future generations. These guidelines are generally established by the National Environmental Policy, outlined in Federal Law No. 6,938/1981, which is considered one of Brazil’s main legal statutes on the environment.

The National Environmental Policy regulates civil liability for damage caused to the environment; this has a strict liability nature (i.e., irrespective of fault). The sole demonstration of the cause-effect relationship between the damage caused and the action or inaction suffices to trigger the obligation to redress environmental damages.

The fact that the wrongdoer’s operations are permitted by environmental licences does not exclude this liability. The National Environmental Policy further expanded the list of parties that may be liable for environmental damage and set joint and several liabilities to polluting entities. Accordingly, all legal entities or individuals directly or indirectly involved in the damaging or polluting activities shall be jointly and severally liable for its recovery.

In the criminal sphere, the Environmental Crimes Act (Federal Law No. 9,605/1998) applies to every person, whether an individual or legal entity, who permits certain behaviours deemed damaging to the environment. As a result, upon occurrence of an environmental violation, a legal entity’s officer, administrator, director, manager, agent or attorney who permits the behaviour deemed to be damaging to the environment will also be subject to criminal penalties. In the administrative sphere, non-compliance with environmental obligations may subject the company to sanctions, such as the imposition of fines of up to 50 million reais (according to federal legislation, fines imposed by state environmental authorities might have a different range), interdiction of activities, cancellation of tax incentives and credit lines with government financial entities.

IBAMA or the competent state environmental agency, in addition to supervising compliance with environmental matters, issues the necessary environmental licences. As a rule, the state environmental agency has jurisdiction for the environmental licensing proceeding of onshore activities, and IBAMA for offshore activities.

The environmental licensing procedure requires companies to submit environmental assessments, such as the environmental impact assessment and an environmental impact assessment report, which is mandatory for facilities that perform activities of significant environmental impact.
The research of seismic data in marine and transition land–sea areas requires a seismic research licence. Oil and gas exploration and production and extended well tests also require the following licences issued by IBAMA and the presentation of the corresponding environmental assessment:

- preliminary licence: granted during the preliminary planning stage of the operations and activities, it approves the location and conception, attests to the environmental feasibility and sets forth the basic and conditioning requirements to be met during the subsequent stages of their implementation;
- installation licence: authorises the implementation of the operations or the activity according to specifications defined in the approved plans, programmes and designs, including environmental control measures and constraints, of which they are determining factors; and
- operating licence: authorises the operation, after the effective compliance with the previous licences and with the environmental control measures and constraints determined for the operation have been verified.

With respect to decommissioning, the operator of a concession area or a PSA area must, upon termination of the agreement, procure the decommissioning and removal of the goods and assets in order to transfer them to the federal government according to the rules set by ANP. ANP may require financial guarantees to be presented during the term of the agreement to cover these obligations.

**VIII FOREIGN INVESTMENT CONSIDERATIONS**

**i Establishment**

Foreign investors must incorporate a company under Brazilian law, with headquarters and administration in Brazil, or acquire interest in a Brazilian company in order to perform operations in Brazil. Operations cannot be conducted by a branch of the foreign corporation.

The entire process of incorporating a local entity usually takes between 30 and 45 days to be completed, as of the date the corporate documents are registered with the commercial registry until the day the company is able to fully operate with all other required government licences and registrations.

All documents related to foreign entities must be notarised by a public notary, stamped by the Brazilian consulate and duly translated into Portuguese, by a sworn translator enrolled in any commercial registry. The company must also be registered with the Brazilian Central Bank.

**ii Capital, labour and content restrictions**

Companies must comply with the local content commitment undertaken in the applicable bid round. Generally, if the commitment is not fulfilled, ANP may impose a penalty of 60 per cent over the amount not complied with, in the event the percentage of local content not observed is less than 65 per cent. If the amount not observed is more than 65 per cent, the penalty may vary between 60 and 100 per cent of the amount not complied with. In 2013, ANP published rules and criteria for the local content certification procedure.

For the 14th bidding round and third PSC bidding round, ANP promoted changes in the local content, reducing the local content levels and the penalties for non-compliance.
Now, the penalties are limited to a maximum of 75 per cent of the value of the required minimum local content. However, companies are no longer able to request waivers for local content commitments that were not fulfilled.

All companies established in Brazil, whether foreign or Brazilian, are required by law to hire Brazilian employees, observing the minimum proportion of two-thirds of Brazilian employees and one-third of foreign employees in the company (which includes the headquarters and each branch with more than three employees). This proportion must also be observed in relation to the payroll, meaning that the remuneration received by the foreign employees must be limited to one-third of the overall payroll.

In order to work in Brazil, a foreign employee must have a work visa and fulfil all the requirements established by the Brazilian National Immigration Council. In this regard, there are two types of visa that allow foreign employees to work in Brazil: (1) a permanent visa: granted to a foreign citizen who will take a managing position in a Brazilian company (officer), and is usually granted for the maximum period of five years; and (2) a temporary visa: granted to foreigners who come to Brazil for short periods of time and have an employment relationship with a Brazilian company.

Brazilian law requires that foreign investments be registered with the Brazilian Central Bank to entitle the foreign investor to overseas dividends, interest on equity and funds related to repatriations of capital. The law establishes broad rules governing the reinvestment of profits and the payment of royalties and technical assistance fees.

Foreign investments must be registered with the Brazilian Central Bank’s computer system by means of the declaratory electronic registration. After the foreign currency funds are exchanged into local currency, the Brazilian beneficiary company must register the investment electronically with the Central Bank, in the currency in which the funds have been remitted to Brazil. This registration is necessary for the remittance of dividends to the investor, for obtaining additional registration upon the reinvestment of profits and for the repatriation of the capital in foreign currency.

iii Anti-corruption

Federal Law No. 12,846/2013 was recently enacted and regulates civil and administrative liability of companies for the performance of corrupt acts against the government. This law establishes a straightforward criterion to hold national or foreign legal entities accountable for any acts of corruption that are detrimental to the government. Parent companies, subsidiaries, affiliates and consortia will be jointly and severally liable for the practice of corrupt acts.

Sanctions include the publication of the conviction and a fine that can reach 20 per cent of the gross sales for the financial year preceding the commencement of the administrative proceedings. If this criterion cannot be applied, the fine will vary between 6 million and 60 million reais. These actions may also result in the suspension or partial banning of activities, and, in severe cases, the compulsory dissolution of the corporation.

IX CURRENT DEVELOPMENTS

Currently under discussion in the Congress is Bill No. 8,939/2017. This seeks to eliminate the restriction set forth in Law No. 12,276/2010, which does not allow Petrobras to assign any working interest in the fields subject to this law.

Even though Bill No. 8,939/2017 has not yet been approved by the Congress, the Federal Auditing Court has issued a legal opinion authorising the bid round for the volumes
of oil that exceeds the volumes under the OAA. In light of that, CNPE, by means of CNPE Resolution No. 06/2019, has already authorised ANP to carry out bids under the production sharing regime for volumes exceeding those contracted under the onerous assignment regime in pre-salt areas (Buzios, Atapu, Itapu and Sepia fields in Santos Basin). Ordinance MME No. 265/2019 governs the co-participation agreement between Petrobras and the companies that win this bid. Given the enormous potential of those fields, it is estimated that such a bid could raise approximately US$25 billion in signature bonuses alone. Those fields will follow a hybrid legal regime: (1) up to 5 billion oil and gas barrels will comply with the regime created by Law No. 12,276/2010 (onerous assignment regime); (2) the additional volumes will comply with the regime created by Law No. 12,351/2010 (production sharing regime) to the extent the reservoir is located inside the pre-salt polygon; and (3) if part of the reservoir is located out of the pre-salt polygon, the regime created by Law No. 9,847/07 (concession regime) may also be applicable to that section.

A key settlement was reached by Petrobras and CADE, the anti-trust body, on 8 July 2019, seeking the liberalisation of the natural gas market in Brazil. By this agreement, Petrobras has undertaken a series of commitments related to the sale of interests in gas transportation and distribution companies and, as regards natural gas production, Petrobras has committed not to acquire new volumes above 1MMm³/day as of the date of execution of the TCC, and to allow third-party access to the production offloading pipeline infrastructure. Considering the gas flaring limitation imposed by ANP, the commitment made by Petrobras by means of the TCC entails the need for producers of gas, especially the associated pre-salt gas, to find viable commercial solutions for the sale of their production under penalty of compromising oil production.

Another important milestone for the oil industry in Brazil was the commencement of the process of permanent offering of areas for oil and natural gas exploration and production. The permanent offer process consists of the continuous offer of returned fields (or fields undergoing a return process) and exploratory blocks offered in previous bids and not sold or returned to ANP. Companies interested in acquiring any of these areas may, at any time, submit a request to ANP, which must carry out the bidding of this area through a simplified process.

Finally, ANP has issued Resolution No. 785/2019, which consolidates the rules applicable to the assignment of rights in oil and natural gas exploration and production contracts, as well as the possibility of pledging the rights arising from these contracts as security for the financing procured for the development of oil and natural gas fields. This created the missing legal base in Brazil to enable reserve base lending operations, which are already widely used in other countries, to be performed.

Lastly, it should be noted that Petrobras’ sale of mature fields continues to evolve well as a way of concentrating its financial and human resources on the development of pre-salt fields. Several Brazilian companies and smaller foreign companies have expressed interest. The major challenge for mature field sales lies in the treatment to be applied to the payment of the abandonment cost. Petrobras is seeking to limit its liability for the payment of these costs, which in many cases leads buyers to question the economic feasibility of the business. However, many companies continue to show interest, and this process could create a new generation of small and medium-sized oil companies in Brazil like the companies that exist in countries such as the United States and Canada.
I INTRODUCTION

China is one of the biggest importers of oil and gas with a rapid increase over the years. In 2018, China replaced Japan and became the biggest importer of gas. China is one of the top 10 oil-producing countries in the world. For 2018, the nationwide production of oil reached 18.9 million tons, with a 1.2 per cent drop from the year before; and the total amount of gas hit 141.512 billion m³, which is a 6.4 per cent increase from the last year.

Every five years, the National Development and Reform Commission (NDRC) and the Energy Bureau organise a five-year plan for the development of oil and gas. The latest ‘thirteenth five-year plan’ explicitly stated that the development route will focus on ‘oil stabilisation and gas increase’ for the period of 2016 to 2020, that the gas industry will be greatly developed in an aim to increase the percentage of gas consumption in the primary energy consumption structure and that for oil consumption China will stick to economised exploitation and green development and maintain the basic stability of oil energy consumption. It is predicted that by 2030, gas will account for approximately 15 per cent of the energy consumption.

The Chinese government is promoting the reform of the oil and gas regime from the perspectives of, inter alia, relaxing market access restrictions, improving pipeline network construction and operation regime, implementing equal access to the infrastructure, forming a market-based pricing system and improving industry management and monitoring. In the oil and gas regime reform, the market will play a better role in resource allocation, and a modern oil and gas market system with fair competition, openness and order will be formed gradually.

According to China’s latest foreign investment policy, namely the Special Management Measures for the Market Entry of Foreign Investment (Negative List) (2019 Version) and the Special Management Measures for the Market Entry of Foreign Investment in Pilot Free Trade Zones (Negative List) (2019 Version) jointly issued by the NDRC and the Ministry of Commerce dated 30 June 2019, the restriction that requires foreign investors to cooperate with Chinese entities in the area of oil and gas exploration and development has been lifted, marking China’s full opening to foreign capital in this sector, as well as the reform and opening of the entire industry from upstream to downstream. As at the end of December 2018, there were 924 prospecting rights licences and 774 mining rights licences issued on...
oil and gas (coal bed methane and shale gas included), with a total coverage of over 3 million square kilometres. Among these licences, 45 of the prospecting rights licences and 37 of the mining rights licences involve foreign investment.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The main legislation specific to upstream oil and gas in China includes but is not limited to: the Constitution, the Property Law, the Mineral Resources Law, the Oil and Gas Pipeline Protection Law, the Atmospheric Pollution Prevention and Treatment Law, the Safety Production Law, the Marine Environmental Protection Law, the Implementation Rules for Mineral Resources Law, the Management Measures on the Transfer of Prospecting and Mining Rights, the Management Measures on the Registration of Mineral Resources Exploration Zones, the Management Measures on the Registration of Mineral Resources Mining, the Rules on Foreign Cooperation in Exploiting Offshore Oil Resources, the Rules on Foreign Cooperation in Exploiting Onshore Oil Resources, the Management Rules on the Environmental Protection in Offshore Oil Exploration and Exploitation, the Regulation on the Safety Production of Offshore Oil and Several Opinions on Deepening the Reform of Oil and Gas Regime.

According to the Constitution and the Mineral Resources Law, as natural resources oil and gas belong to the state, and the State Council on behalf of the state exercises the ownership right over mineral resources. Geologically, all oil and gas that is inland and that occurring in the internal waters, territorial seas and continental shelf of the People's Republic of China and in all sea areas within the limits of national jurisdiction are owned by the state.2

Oil and gas are subject to the regulation of the mining industry rules, such as the Mineral Resources Law.

Foreign companies may choose to develop oil and gas in China by cooperating with Chinese counterparts. The Rules on Foreign Cooperation in Exploiting Offshore Oil Resources and the Rules on Foreign Cooperation in Exploiting Onshore Oil Resources are the main legislation governing foreign cooperation in oil and gas development matters. Foreign companies can cooperate with Chinese oil companies that have the exclusive rights over oil and gas development, which are the China National Petroleum and Natural Gas Corporation Group and the China National Petroleum and Chemicals Corporation Group for onshore oil and gas cooperation and the China National Offshore Oil Corporation for offshore oil and gas cooperation (each a 'Chinese Oil Company'). The investment ratio may be negotiated by the parties. The foreign contractor is required to establish a branch, a subsidiary or a representative organisation in China. The foreign contractor is allowed to ship abroad the oil and gas products due to it or purchased by it, and it is also entitled to transfer out of China its recovered investment, profit and other lawful earnings.

2 See the Rules on Foreign Cooperation in Exploiting Offshore Oil Resources, and the Rules on Foreign Cooperation in Exploiting Onshore Oil Resources.
ii Regulation
According to the division of responsibilities, the main regulatory agencies for upstream operations such as oil and gas prospecting and mining include:

- the NDRC, which is responsible for the approval of foreign cooperation on oil and gas projects (including the overall development plan for risk exploration and development blocks);
- the Department of Geological Exploration of the Ministry of Natural Resources (formerly the Department of Geological Exploration of the Ministry of Land and Resources), which is responsible for organising the drafting of strategies, policies and plans for energy and mineral resources, undertaking prospecting rights and mining rights management for oil, natural gas, coal bed methane and radioactive mineral resources, and reviewing and supervising foreign cooperation zones.

In addition to the above competent departments, the administrative authorities, such as environmental protection and production safety, will also implement environmental and safety management and regulation in the exploration and exploitation of oil and gas according to their respective functions.

iii Treaties
China is one of the contracting parties to international conventions such as the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention), the Convention on the Delivery of Civil or Commercial Judicial Documents and Extrajudicial Documents to Foreign Countries (the Hague Convention) and the Convention on the Taking of Evidence Abroad in Civil or Commercial Matters.

Currently, China has signed a number of bilateral or multilateral investment treaties with countries such as Tunisia, Germany, the Philippines, Luxembourg, North Korea, Finland, Namibia, the Czech Republic, Spain, Portugal, Madagascar, the Republic of Equatorial Guinea, the Republic of Vanuatu, the Seychelles, Russia, Romania, Cuba, Switzerland, Colombia, Mexico, France, Costa Rica and the Republic of Korea. As for oil cooperation, China has signed bilateral agreements, cooperation agreements, memoranda of cooperation and framework agreements with countries such as Pakistan, Egypt, Ecuador, Iran and India.

China has currently signed three multilateral tax treaties, namely the Multilateral Tax Administration and Mutual Assistance Convention, the Multilateral Competent Authority Agreement on Automatic Exchange of Financial Account Information and the Multilateral Convention to Implement Tax Treaty Related Measures to Prevent Base Erosion and Profit Shifting, the latter two of which have not yet come into force. As of October 2017, China has signed double tax avoidance agreements with 103 countries, including the United States, Japan, France, the United Kingdom, Germany, Belgium, Canada, Malaysia, New Zealand, Singapore, Thailand, Switzerland, Spain, Brazil, South Korea and Cambodia.

III LICENSING
Oil and gas are classified in China as mineral resources. For the exploration and exploitation of oil and gas, respective prospecting and mining licences must be legally obtained.

The prospecting right and mining right (collectively referred to as ‘mining rights’) in China are mainly obtained through administrative licensing. According to the Management Measures on the Registration of Mineral Resources Exploration Zones and the Management
Measures on the Registration of Mineral Resources Mining, the application for exploration and exploitation of oil and gas resources must be approved and registered by the competent department of the State Council (the former competent department of China was the Ministry of Land and Resources, after reform in 2018 the current competent department being the Ministry of Natural Resources), and the licences shall be awarded accordingly. Only those qualified enterprises approved by the State Council can apply for oil and gas mining rights.3

The administrative licensing process for applying for a prospecting right certificate and mining right certificate is as follows. First, submit the application documents according to the list of documents published on the website of the Ministry of Natural Resources. If the application documents are complete, the exploration department will accept the application, inquire at the provincial natural resources agencies about the status of mining rights, consult with other departments and thereafter submit the application for joint review by the Ministry of Natural Resources. The Ministry will then decide whether the application will be approved and registered accordingly. For the exploration implementation plan or development and utilisation plan in some projects, expert review might also be anticipated. After the approval is awarded by the Ministry of Natural Resources, a written formal reply will be sent to the applicant from the government office within 10 working days of the date of the approval decision.

In June and July 2017, the Ministry of Finance and the Ministry of Land and Resources promulgated the Reform Plan for the Mining Rights Transfer Regime and the Interim Measures for the Administration of the Mining Rights Transfer Income Collection. In accordance with these, the transfer of the mining rights through public bidding, auction and other competitive ways is promoted.

The content of prospecting and mining licences mainly includes information on the mining rights holder, the address, the name of mining area, the type of enterprise, the validity period, the type of mine, the mining and prospecting mode, the volume of production, the total area and the location.

The oil and gas prospecting rights licences are valid for a maximum of seven years. The validity period of the mining right licence is determined according to the scale of the mine. For large-scale mining projects, the mining right licence is valid for a maximum of 30 years; for medium-scale ones, the mining right license is valid for a maximum of 20 years; for small-scale ones, the mining right licence is valid for a maximum of 10 years. Where rolling exploration and development is involved, the mining right licence is valid for a maximum of 15 years.

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4 Management Measures on the Registration of Mineral Resources Exploration Zones, Article 6; Management Measures on the Registration of Mineral Resources Mining, Article 5.
5 Guidance for New Application of Prospecting Right (oil and gas), Paragraph 11; Guidance for New Application of Mining Right (oil and gas), Paragraph 11.
Exploration and mining licences can be revoked in the following cases:

a. failure to submit annual reports, or refusal to cooperate in case of supervision or inspection, or falsification, and the circumstances are serious;

b. failure to pay the due fees on time, and no remedy even after the extended time limit prescribed by the authority;

c. in the event of no registration of the alteration of the mining licence or its cancellation, and no remedy even after the extended time limit prescribed by the authority; and

d. the unauthorised transfer of the prospecting rights or the mining rights and the circumstances are serious.

The exploration licence can also be revoked if the following acts are committed and no remedy even after the extended time limit prescribed by the authority: (1) the minimum prospecting investment has not been made; (2) no prospecting operation for six months after receiving the prospecting right licence or the prospecting operation has been unreasonably stopped for six months.

IV PRODUCTION RESTRICTIONS

Generally speaking, after the release of the Special Management Measures on Foreign Investment Access (Negative List) (2019 edition), which removed the previous requirement of foreign investment in the sole form of cooperation with domestic enterprises, there is no restriction on oil and gas production in China. For oil and gas obtained by a foreign investor, there is no legal restriction on exportation to foreign countries subject to sanctions of embargo.

For foreign investors willing to sell oil and gas in China, according to the Special Management Measures on Foreign Investment Access (Negative List) (2019 edition), the previous requirement for a controlling stake of a Chinese party on the business of building or operation of an urban gas pipelines is also removed. This means that theoretically no more restriction is prescribed in terms of the distribution of oil and gas. Notwithstanding the negative list above, as no precedents are yet known given the short term after the release thereof, further complementary legislative measures are expected for its implementation in practice.

In terms of sales price, oil and gas pricing is regulated by the NDRC by means of macro-controls. The price of crude oil is subject to market regulation. The pricing of refined oil products will be determined subject to the government-guided price or government direct pricing in different cases. The station price of the natural gas shall refer to the government-guided pricing with a maximum ceiling price, for which both the purchaser and the seller can negotiate and determine the specific price lower than the maximum price set by the state. Pricing policies including the price ladder for residential usage and seasonal variable pricing can be applied.

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6 Management Measures on the Registration of Mineral Resources Exploration Zones, Articles 29, 30, 31; Management Measures on the Registration of Mineral Resources Mining, Articles 18, 21, 22.
7 Management Measures on the Transfer of Prospecting and Mining Rights, Article 14.
8 Special Management Measures on Foreign Investment Access (Negative List) (2019 edition)
9 Notice of the State Council on Implementing the Price and Tax Reform of Refined Oil.
10 Notice of the National Development and Reform Commission on Adjusting the Natural Gas Prices.
11 Measures for the Administration of Natural Gas Infrastructure Construction and Operation, Article 24.
V ASSIGNMENTS OF INTERESTS

The transfer of mining rights involves the transfer of prospecting right and mining right. Pursuant to Article 6 of the Mineral Resources Law, the transfer of prospecting right and mining right shall be approved by the competent government authorities in accordance with the law. Prospecting right and mining right may not be transferred unless:

- after the completion of the specified minimum exploration investment, the prospecting right holders can transfer the exploration rights to others with due approval;
- if a mining enterprise that has acquired mining rights needs to change its mining rights because of mergers, divisions, joint ventures or cooperative operations with others, or because of the sale of corporate assets and other changes in the assets of the enterprise, the mining rights can be transferred to others with due approval.

The government has no pre-emptive right in terms of transfer of mining rights. Only the prospective right holder priority is stipulated by law, that is, the prospecting right holder has the privilege right to carry out the specified exploration operations within the designated exploration operation area and has the right of first refusal to obtain the mining rights of the mineral resources in the exploration operation area.

Currently no government approval is required for the change of shareholders of a holder of a mining licence. According to current legal precedents, if the mining rights licence holder shown on the mining rights licence does not change, no prior governmental approval similar to mining right transfer is needed for the share transfer of the licence holder.

The transfer of prospecting and mining rights is subject to the conditions stipulated by law. The transfer of prospecting rights shall meet the following conditions: (1) two years have passed from the date of issuance of the exploration licence, or mineral resources are discovered for further exploration or exploitation in the survey area; (2) completion of the minimum survey investment; (3) the prospecting rights are undisputed; (4) the prospecting loyalties have been paid; and (5) other conditions as may be stipulated by the competent department of geology and mineral resources under the State Council.

For the transfer of mining right, the following conditions must be met: (1) the mining enterprise has mined for at least one year; (2) the mining rights are undisputed; (3) the mining loyalties have been paid; and (4) other conditions as may be stipulated by the competent department of geology and mineral resources under the State Council.

After the transferee pays the relevant fees and loyalties in accordance with the laws and regulations, it will obtain the exploration licence or the mining licence to become the prospecting or mining right holder.

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12 Management Measures on the Transfer of Prospecting Right and Mining Right, Articles 5 and 6.
13 Management Measures on the Transfer of Prospecting Right and Mining Right, Article 10.
VI   TAX

i   Summary of the tax regime applicable to upstream oil and gas operators

In the current Chinese oil and gas resource tax system, the main types of taxes and fees applicable include value added tax, resource tax, environmental protection tax and prospecting and mining royalties.

Value-added tax

As of 1 April 2019, for the taxpayer of value-added tax on the taxable sales behaviour of oil and gas resource or its importation, the original applicable tax rate of 16 per cent and 10 per cent has been adjusted to 13 per cent and 9 per cent respectively.  

Resource tax

The entity undertaking oil and gas production in Chinese territory and jurisdictional waters should pay resource tax. The resource tax rate is 6 per cent.  

Environmental protection tax

In the process of oil and gas exploitation, the entity that directly discharges taxable pollutants (including atmosphere, water, solid waste and noise pollution) shall pay environmental protection tax in accordance with the Environmental Protection Tax Law, which came into effect on 1 January 2018. A form of tax rates is attached to the law for reference, which provides a tax rate based on different pollutants.

Prospecting and mining royalties

Prospecting licence and mining licence holders are eligible taxpayers. The prospecting royalty is calculated and paid annually on the basis of block area. From the first to third prospecting years, it shall be 100 yuan–500 yuan per square kilometre per year. The mining royalties are paid annually on the basis of the mining area, with a rate of 1,000 yuan per square kilometre per year.

Oil and gas exploration and development enterprises need to pay corporate income tax and may also need to pay land use, sea use and other taxes and fees that are normal taxes and fees for the operation of an enterprise in accordance with relevant laws and regulations.

14 Interim Regulation of the People’s Republic of China on Value Added Tax, Article 2.
15 Notice of the Ministry of Finance and the State Administration of Taxation on Adjusting Value-added Tax Rates, Paragraph 1.
16 Announcement of the Ministry of Finance, the State of Taxation Administration and the General Administration of Customs on Relevant Policies for Deepening the Value-Added Tax Reform, Articles 1–3.
17 Interim Regulations on Resource Tax of the People’s Republic of China (Revised in 2011) and Notice of the Ministry of Finance and the State Administration of Taxation on Adjusting the Relevant Policies for Resource Tax on Crude Oil and Natural Gas, Paragraph 1. Law on Resource Tax of the People’s Republic of China was passed on 26 August 2019 and will enter into force on 1 September 2020, replacing Interim Regulations on Resource Tax of the People’s Republic of China. The resource tax rate for oil and gas production will remain at 6 per cent.
18 Environmental Protection Tax Law, Article 8.
19 Measures on the Administration of the Use of the Use Fees and Payments for Mine Prospecting and Exploiting Rights, Article 5.
Special oil gains

Enterprises that independently exploit and sell the crude oil in China and enterprises that exploit and sell crude oil in the form of equity or contractual joint venture in China shall pay special petroleum proceeds, which are levied on the excessive returns obtained by the petroleum exploitation enterprises from their sales of domestic crude oil when the price thereof exceeds US$40 per barrel. The ratio for the collection of special petroleum proceeds shall be determined on the basis of the monthly weighted average price of the crude oil sold by the petroleum exploitation enterprises and vary from 20 per cent to 40 per cent.20

ii Tax incentives applicable to oil and gas operators

According to the existing preferential tax policies, oil and gas exploration developers enjoy the following tax incentives.

Resource tax incentive

Oil and natural gas used for heating in the transportation of heavy oil within the oilfield are exempt from resource tax. For taxable types, such as heavy oil, high-condensation oil, high-sulphur natural gas, tertiary oil recovery, low-abundance oil and gas fields and deep-water oil and gas fields, shale gas, and mineral resources under buildings, railways and water bodies mined through the cut and fill mining method, tax incentives ranging from 20 per cent to 50 per cent are applied respectively.21

Environmental protection tax incentive

If the concentration index of air pollutants or the water pollutants emitted by the miners is lower than the national and local standards by 30 per cent or 50 per cent, they will enjoy the preferential tax incentive on environmental protection tax, which shall be reduced by 75 per cent and 50 per cent respectively.22

Prospecting and mining royalty incentive

Remission of prospecting and minding royalties may apply to certain activities in the west, remote and poor areas and the seas in China determined by the State Council, including prospecting and mining for deficient mineral resources, and substitute resources, by large and medium-sized mining enterprises or by applying new technologies and technics, etc.23

20 Decision of the State Council on the Collect of Special Petroleum Proceeds; Notice of the Ministry of Finance on Issuing the Measures for the Administration of the Collection of Special Petroleum Proceeds.
21 Notice of the Ministry of Finance and the State Administration of Taxation on Adjusting Relevant Policies Regarding Oil and Natural Gas Resource Tax, Paragraph 2.
22 Environmental Protection Tax Law, Article 13.
23 Notice of the Ministry of Land and Resources and the Ministry of Finance on Issuing the Measures for the Deduction and Exemption of Charges for Using the Mineral Prospecting Right and Mining Right, Article 3.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The most important law is the Environmental Protection Law (revised in 2014), which came into effect on 1 January 2015. The law set up the basic principles of “Protection Priority, Prevention First, Integrated Governance, Public Participation, Damage Responsibility”. Meanwhile, it also clearly stipulates the basic requirements of environmental protection for the enterprise polluters in the process of production and operation, such as rational development, the protection of biodiversity and ecological security when developing and utilising natural resources. The Marine Environmental Protection Law, further stipulates that effective measures should be taken during offshore oil exploration and development and oil transportation so as to avoid oil pollution and other environmental pollution accidents.24 Regarding different types of pollutants, China also has in place the Atmospheric Pollution Prevention and Treatment Law, the Law on Prevention and Control of Water Pollution and the Law on Prevention and Control of Environmental Pollution by Solid Waste. The Environmental Impact Assessment Law and the Clean Production Promotion Law have established an environmental impact assessment system and a clean production promotion system. In addition, many rules are also set up at the ministerial and local levels.

Globally, China is also a party to a series of international conventions in terms of environmental protection, including the Convention on Biological Diversity, the Basel Convention on the Control of Transboundary Movements of Hazardous Wastes and their Disposal, the United Nations Framework Convention on Climate Change, the Kyoto Protocol, the Montreal Protocol on Substances that Deplete the Ozone Layer and the Vienna Convention for the Protection of the Ozone Layer.

The key environmental approvals and licences currently required for oil and gas exploration and development activities in China are as follows.

i Environmental impact assessment

According to the Environmental Impact Assessment Law effective on 1 September 2016 and amended on 29 December 2018, for both onshore, coastal and offshore construction projects an environmental impact assessment is required, and the environmental impact reports shall be submitted to the competent environmental protection administrative department for approval, without which the construction of the project cannot be started.25

ii Discharge permit

According to the Law on the Prevention and Control of Water Pollution, the Law on the Prevention and Control of Atmospheric Pollution and Measures for Pollutant Discharge Permitting Administration (For Trial Implementation) issued by the Ministry of Environment Protection (now Ministry of Ecology and Environment), oil and gas enterprises that directly or indirectly discharge industrial waste water, industrial waste gas and other toxic and

24 Marine Environmental Protection Law, Article 50.
25 Law of the People's Republic of China on Environmental Impact Assessment, Article 25; Marine Environmental Protection Law, Article 43; Administrative Regulation on the Prevention and Treatment of the Pollution and Damage to the Marine Environment by Marine Engineering Construction Projects, Article 8; Administrative Regulation on the Prevention and Control of Pollution Damages to the Marine Environment by Coastal Engineering Construction Projects of the People's Republic of China, Article 7.
hazardous atmospheric pollutants shall obtain a discharge permit.\textsuperscript{26} For the dumping of marine waste involved in offshore oil exploration and development, the corresponding waste discharge permit should also be obtained.\textsuperscript{27}

iii Water permit

According to the Regulation on the Administration of Water Permits and Water Resource Fees (Revised in 2017), which came into force on 1 March 2017, only when the water permit application is approved by the water administrative department of the corresponding government at or above the county level, should the entity undertaking oil and gas exploration and development construct water intake projects or facilities to take water for use of production and operation accordingly.\textsuperscript{28}

iv Summary of legal requirements with respect to decommissioning

A mining enterprise is the responsible entity for the restoration of the geological environment of the mine. When the mining right applicant applies for a mining licence, the applicant shall prepare a mine geological environment protection and recovery plan.\textsuperscript{29} Enterprises raise funds to finance the restoration work. Since 21 May 2018, the original ‘restoration of mine geological environment recovery deposit’ has been cancelled and replaced by ‘mine geological environment recovery fund’. In accordance with the principle of meeting actual needs, the mining enterprise can use the fund independently and specifically for the purpose of environmental recovery in accordance with the budget, the engineering implementation plan and the schedule identified based on the mine’s geological environment protection and land recovery plan. Mining enterprises need to set up fund accounts in their bank accounts, which can independently reflect the status of withdrawal transactions. The withdrawal and use of the funds and the implementation of mine geological environment protection and recovery plans shall be included in the exploration and mining information disclosure system.\textsuperscript{30}

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

With the publishing of the Special Management Measures on Foreign Investment Access (Negative List) (2019 edition) on 30 June 2019, which started entering into effect from 30 July 2019, foreign companies now are free to engage in oil and natural gas exploration and development as well as the investment in the construction and operation of urban gas pipe networks, heating power pipe networks and water supply and sewage pipe networks in a city with more than 500,000 residents.

\begin{itemize}
\item \textsuperscript{26} Water Pollution Prevention and Control Law, Article 21; Atmospheric Pollution Prevention and Control Law, Article 19.
\item \textsuperscript{27} Regulations of the People’s Republic of China on the Control over Dumping Wastes into the Sea Waters, Articles 6 and 9.
\item \textsuperscript{28} Regulation on the Administration of the Licence for Water Drawing and the Levy of Water Resource Fees, Articles 21 and 23.
\item \textsuperscript{29} Provisions on the Protection of the Geologic Environment of Mines, Articles 12 and 13.
\item \textsuperscript{30} Provisions on the Protection of the Geologic Environment of Mines, Article 18 Section 2.
\end{itemize}
According to the Interim Administrative Measures for the Record-filing of the Incorporation and Change of Foreign-invested Enterprises (revised in 2018), the establishment of a foreign invested company that does not involve the implementation of special access administrative measures prescribed by the state shall file and submit the recording-filing information to the local market regulation administrations (the record-filing institutions).

According to Article 8 of Interim Administrative Measures for the Record-filing of the Incorporation and Change of Foreign-invested Enterprises (Revised in 2018), the record-filing information includes:

- a) application materials for the prior approval of the name of foreign-invested enterprises or business licences of foreign-invested enterprises;
- b) a letter of commitment regarding the record-filing of the incorporation by foreign-invested enterprises signed by all investors (or all initiators) of foreign-invested enterprises or their authorised representatives, or letter of commitment regarding the record-filing of the change of foreign-invested enterprises signed by all investors (or all initiators) of foreign-invested enterprises or their authorised representatives;
- c) the certification of the relevant documents testifying that all investors (or the board of directors of foreign-invested companies limited by shares) or foreign-invested enterprises designate representatives or jointly entrusted agents, including the power of attorney and the identification certificates of the trustee;
- d) the certification of the relevant documents testifying that the investors of foreign-invested enterprises or legal representatives entrust another party to sign the relevant documents on their behalf, including a power of attorney and the identification certificates of the trustee (if no other party has been entrusted to sign the relevant documents, there is no need to provide them);
- e) investors’ subject qualification certification or natural person identity certification (if the change does not involve the basic information of the investors, there is no need to provide this);
- f) natural person identity certification of legal representatives (if the change does not involve a change of legal representatives, there is no need to provide this);
- g) share chart of the final actual controllers of a foreign-invested enterprise (not applicable, in the case that no final actual controller of a foreign-invested enterprise is involved in any changes); and
- h) if a foreign investor pays with the equities of an overseas company, a certificate for outbound investment by an enterprise shall be provided by the domestic enterprise which obtains the equities of the overseas company.

Where the original of an above-mentioned document is made in a foreign language, the Chinese translation version shall also be uploaded and submitted; the foreign-invested enterprise or its investors shall ensure that the content of the translated version is consistent with that of the original.

The record-filing institutions shall then verify the completeness and accuracy of the filled-in information in the form and will check whether the reporting matters fall within the scope of the record-filing. And after receiving full and accurate information, the record-filing institutions shall complete the record-filing within three business days.

Foreign companies that establish representative offices in China for cooperation in the development of oil and natural gas must firstly obtain approval from relevant competent departments of the state council. Within 90 days of obtaining approval, the foreign company
shall apply to the competent local authority for registration and submit relevant approval
documents. The local competent authority shall, within 15 days of the date of accepting
the application, make a decision on whether or not to approve the registration and issue a
registration certificate and a representative certificate to the applicant within five days of the
date of the decision.

ii Capital, labour and content restrictions

Capital control

China pursues a foreign exchange control policy. After a foreign-invested enterprise is legally
established, it shall register in the foreign exchange bureau, and all its subsequent capital
changes such as capital increase, capital reduction and equity transfer shall be subject to
modification of registered information in the foreign exchange bureau. It also requires
that the capital of foreign-invested enterprises in foreign currency and the yuan exchanged
from it should be used within the business scope of the enterprise and shall conform to the
authenticity and self-use principle.

Labour

At present, there is no restrictive requirement for the proportion of Chinese and foreign
employees in enterprises. Generally speaking, foreign employees employed by enterprises
need to obtain Z visas before arrival (or be otherwise processed based on a mutual visa
exemption agreement) and the foreigner employment permit and the residence permit after
the arrival.

For joint ventures and cooperative enterprises engaged in offshore oil exploration, their
foreign employees do not need to obtain the foreigner employment permit. The foreigner's
work permit for offshore oil operation in the People's Republic of China will suffice.

Raw material restrictions

China does not have any restrictions regarding the raw material (equipment) involved in the
exploration and development of oil and gas. On the contrary, China provides tax reduction,
exemption or other tax incentives in accordance with laws and regulations for imported
equipment and materials used for the implementation of petroleum contracts.

iii Anti-corruption

China has promulgated the Law against Unfair Competition, Interim Provisions of the State
Administration for Industry and Commerce on Prohibition of Commercial Bribery and
other regulations to govern commercial bribery. In addition, the Criminal Law of the People's
Republic of China provides a chapter on 'embezzlement and bribery crimes' and criminal
liability will be investigated against corruption and bribery (inclusive of commercial bribery).
Since 12 February 2006, the United Nations Convention against Corruption has entered
into force in China, further expanding and clarifying the scope of commercial bribery, and
facilitating the integration of China's anti-corruption battle along with the rest of the world.

Since 2013, China has vigorously carried out an anti-corruption campaign. The
Supervision Law was promulgated on 20 March 2018 along with the establishment of the
National Supervision Commission of the People's Republic of China, which is responsible for
anti-corruption work against all public servants.
IX CURRENT DEVELOPMENTS

i Opening and reform

China has devoted huge efforts in the opening and reforming of the whole industry chain of its oil and gas business and operation as a part of its current focus of economic development – optimising the business environment and promoting the formation of a new pattern of comprehensive market opening. Official documents like the Notice of the General Office of the State Council on Issuing the Program of Action for the Energy Development Strategy (2014–2020), the Outline of the 13th Five-Year Plan for the National Economic and Social Development and the Several Opinions on Deepening the Reform of Oil and Gas Regime all emphasise that in the 13th Five-Year Plan during the period from 2016 to 2020, reform of the oil and gas regime will be deepened in terms of the market entrance, improvement of the pipeline network construction and operation mechanism, fair access to infrastructure, market pricing and improvement of industry management and supervision, aiming at facilitating the decisive role that the market plays in resource allocation.

On 27 February 2019, the State Council published the Decision on the Cancellation and Delegation of a Batch of Administrative Licensing Items, in which the overall reviewing and approving of Sino-foreign cooperative oil (gas) field exploration plans has been cancelled and replaced by record filing. Between March and May a series of regulations that are related to the border opening of oil and gas pipeline facilities as well as creating a fair playground for all market parties in the access of the pipeline facilities were published including the Opinions on Reform and Implementation of Operation Mechanism of Petroleum and Natural Gas Pipeline Network, in which the plan to separate the pipeline operation and the exploration and sales of oil and gas by establishing a professional oil and gas pipeline company and separating these businesses from the nationally owned oil and gas giant, Sinopec Group. The publishing of the Special Management Measures on Foreign Investment Access (Negative List) (2019 edition) on 30 June 2019, which shall be in effect from 30 July 2019, is been treated as the sign of all-round opening of the oil and gas business in China.

On 15 March 2019, the Ministry of Natural Resources announced a new Regulation – Regulation on the Assignment of Mining Right – for public opinion. This new regulation, which is expected to be officially published in the near future, shall bring significant improvement to the regulation of the assignment of the mining right. For instance, the new Regulation clarifies that, other than in very few exceptions, the mining right must be assigned through a public method such as bid invitation, auction and listing, and the right to approval exploration and mining of oil and gas being directly under the authority of Ministry of Natural Resources.

ii Booming market of oil and gas and shadows of the trade war

China is in the process of energy transformation, during which cleaner and more environmentally friendly energy such as that from oil and gas resources (gas in particular), compared with traditional coal resources, is gradually becoming one of the most important energy sources in this period. Since 2016, the clean heating in winter and the industrial and civil ‘coal converting to gas’ project in the northern part of China has gradually become one of the national policies.

The success of the US shale gas revolution has shown China the potential of alternative resources. Therefore, in the past two years and at least in the following decade, the exploration and development of alternative resources will become a new focus in China’s oil and gas
industry. As per the estimation of various agencies such as the China Geological Survey Bureau, the United Nations Conference on Trade and Development (UNCTAD), and the US Energy Information Administration (EIA), the alternative resource is abundant in China, which was also confirmed by Yu Haifeng, the director of the Geological Exploration Department of the Ministry of Natural Resources at the press conference in August 2017 that, after years of exploration and exploitation practices, a major breakthrough has been achieved in the exploration and exploitation of shale gas in China. Meanwhile, since last year, with the escalating of the trade tension between the US and China, the amount of LNG imported from the US has gone down dramatically. Besides, China’s overseas investment in unconventional oil and gas projects has also been affected by the trade war. In November 2017, during President Trump’s visit to China, China National Energy Investment Group agreed to invest US$83.7 billion into the exploitation of shale gas and chemical project in West Virginia; however, in September 2018, with the increasing tension between the two countries, China declared the cancellation of this investment.
Chapter 7

COLOMBIA

José V Zapata Lugo and Claro M Cotes Ricciulli

I INTRODUCTION

Currently Colombia is under a new government, presided over by President Ivan Duque. The government has aimed its efforts in attracting foreign investors through the implementation of regulations that promote industries such as the oil and gas sector. It is important to state that these regulations for promoting investment in the country had already started to be issued. Thus, governmental agencies have been focusing on evaluating the best manner to improve the rule of law so as to allow for increased interest in the oil and gas sector. Nonetheless, the development of exploration and production activities in unconventional reservoirs suffered an important setback as the Council of State ordered, as an interim measure, the suspension of the regime under which these activities were regulated. Oil average production has presented a partial recovery in comparison to previous years, fluctuating from an average production of 848 thousand barrels per day (KBPD) in 2018, to 872KBPD up to May 2019.² This continues to confirm that the creation of exploration incentives, and promotion continues to be a matter of relevance, considering the favourable conditions in neighbouring countries and that exploration activities have decelerated. The outlook for the sector has been very favourable, as higher production has been achieved, reaching about 900KBPD,³ similar numbers to those for 2016. Similarly, the National Hydrocarbons Agency (ANH) has seen increased proposals for new exploration and production contracts, and alongside Agreement 2 of 2017 and its recent modifications made through Agreement 3 of 2019, related to the possibilities and procedure for the withdrawal of a contract by the contractor, and an exception to the presentation of the joint and several debtor’s guarantee to those companies recognised in various international rankings.

Additionally, assignment of new areas under the new permanent contracting conditions was carried out in June and July 2019, resulting in 11 assigned areas – 10 continental and one offshore. Therefore, Colombia continues to advance in its attempt to provide structural and regulatory reforms to reactivate the oil and gas industry, as well as legal stability that guarantees the rule of law, which is profoundly needed, particularly regarding the rulings of the judicial branch. The government has expressed its strong intention to bet for offshore production, which has been evidenced, for example, in new discoveries in the Colombian

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1 José V Zapata Lugo is a partner and Claro Manuel Cotes Ricciulli is an associate at Holland & Knight.
2 www.anh.gov.co/Operaciones-Regalias-y-Participaciones/Sistema-Integrado-de-Operaciones/Paginas/Estadisticas-de-Produccion.aspx.
Caribbean Sea, along with the issuance of a new model of the offshore contract. This new contract model includes certain provisions that are attractive to foreign investors, such as a provision under arbitration clause that allows international arbitration as long as certain Colombian law conditions are met.

In 2003, the Colombian government enacted Decree 1760 by means of which two substantive changes for the Colombian petroleum industry were adopted: (1) the creation of the ANH as a special administrative unit to be in charge of the administration and regulation of hydrocarbons in Colombia (at a later stage, Decree 4137 of 2011 modified the legal nature of the ANH and converted it into a state agency); and (2) the transformation of the legal nature of Ecopetrol into a corporation (by means of Law 1118 of 27 December 2006, Ecopetrol adopted the legal nature of partially state-owned company) dedicated exclusively to the upstream and downstream business inside and outside Colombia, and, therefore, it submitted the applicable regime of its acts and agreements to private law.

With those changes, Colombia started to be a more competitive state as Ecopetrol became another competitor in the market, leaving the sole regulatory and administrative management of hydrocarbons to the ANH. However, since 2014, exploratory activities have been in steady decline, but lately showing some signs of a slight recovery.

Under the term of President Ivan Duque, the country expects support from government for the industry reactivating exploration activities, which should also increase as a result of the implementation of the peace process.

In the first quarter of 2019, 74 exploratory wells were drilled, which represents a 61 per cent decrease compared to the same period in 2018. Oil reserves are estimated at 1,958 million barrels of oil, increasing from the 2017 estimate of 1,782 million barrels of oil. Nevertheless, they still represent a significant decrease compared to the 2,002 million barrels of oil reserve estimated in 2015.

Regarding gas production, as of May 2019 compared to 2018, one can detect a significant increase, as production reached an average of 1,128 million cubic feet per day. The previous reflected an important recovery in the production level, compared to the 1,133 million cubic feet per day produced in 2015 and the average production of 1,081 million cubic feet per day produced during 2016.

There are still changes that need to be incorporated since the government must provide and ensure greater legal stability for investors as well as establishing contractual terms that are much more attractive to investors.

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6 https://www.dinero.com/pais/articulo/cuales-son-las-reservas-de-crudo-de-colombia/271718.
7 https://www.datos.gov.co/Minas-y-Energia/Reservas-De-Petroleo/2njd-akei/data.
8 www.anh.gov.co/Operaciones-Regalias-y-Participaciones/Sistema-Integrado-de-Operaciones/Paginas/Estadisticas-de-Produccion.aspx.
9 www.anh.gov.co/Operaciones-Regalias-y-Participaciones/Sistema-Integrado-de-Operaciones/Paginas/Estadisticas-de-Produccion.aspx.
II LEGAL AND REGULATORY FRAMEWORK

In Colombia, there is a clear differentiation between the upstream, midstream and downstream oil and gas regulations. The midstream and downstream levels gas regulation must be differentiated in multiple aspects from that relating to crude oil. The 1991 Constitution determines that the state is the owner of the subsoil and of non-renewable natural resources, without prejudice to grandfathered rights. Similarly, the basis for royalties is constitutionally defined by establishing that any production of non-renewable natural resources shall entail a royalty in favour of the state in addition to any further right or compensation that is agreed to.

As to the underlying titles or agreements that allow for the exploration and exploitation of hydrocarbons, Colombian regulations refer to: (1) association contracts (the association agreements) still in effect with Ecopetrol; (2) the technical evaluation agreements (TEAs); and (3) exploration and production contracts (E&Ps) entered into with the ANH. These various forms of contractual agreements allow any party to develop its activities in the oil and gas sector. As to the regulations in place for the development of hydrocarbons activities, rules have been issued essentially by the Ministry of Mines and Energy while the ANH has defined particular rules for TEAs and E&Ps in its condition as a state agency in charge of executing these contracts with the corresponding participants. A final set of rules are those that regulate environmental and social conditions for the development of operations in oil and gas. One must remember the various timelines that each of these sets of regulations entail and the manner in which exploration and production activities must be completed.

The hydrocarbons sector in Colombia has been developed since the early 1940s. The Colombian Petroleum Code (the Code) dates back to 1953 as a significant starting point for all matters associated with oil and gas. Parties seeking to enter into an association agreement, a TEA or an E&P contract will be required to verify whether their legal, financial, technical, operational, environmental and social capacities allow them to farm in or access a new underlying agreement, according to ANH capacity thresholds.

As per the midstream and downstream levels, gas regulation is separated in a significant manner from oil regulations. Considering the technical definitions, gas regulations encompass aspects ranging from contractual relations, technical standards, transport conditions, sale terms, distribution, consumption and heads of power to further regulate such matters. The Commission on Regulation of Energy and Gas (CREG) is the principal governmental entity that regulates these aspects since its inception under Laws 142 and 143 of 1994. Gas has been considered directly linked to public utilities and fundamental constitutional rights. The belief that gas belongs to a more local market has led to this separate set of rules.

i Domestic oil and gas legislation

As a civil law system, Colombia has a tradition of sector-specific regulations affecting all aspects of upstream, midstream and downstream operations. When reference is made to oil and gas at the upstream level, the regulatory framework includes norms, technical rules, structure regulations and historic norms.
Framework regulations are essentially found in the Petroleum Code. While various aspects of such Code have undergone modifications since 1953, the Code continues to be of fundamental relevance to many aspects of the oil and gas industry, providing the key regulatory guidelines. The perception of the petroleum industry as of public interest in aspects of exploration, production, refining, transport and distribution, is a relevant factor. Also, all data obtained during the course of scientific, technical, economic or statistical activities must be provided to the Colombian government, as part of the duties that parties involved in the oil and gas industry must abide with. Aspects relating to contracts, royalties and fines have since been updated by further regulations.

Technical rules that were contained in the Petroleum Code have also been updated. Decrees 70 of 2001 and 3724 of 2009, granted regulatory powers to the current Ministry of Mines and Energy. Accordingly, Resolution 181495 of 2009 was issued. This Resolution fully comprehends the main regulatory framework for the exploration and production of hydrocarbons with the purpose of maximising their recovery and avoiding waste. Resolution 181495 (updated by Resolution 40098 of 2015) establishes that the Ministry of Mines and Energy is in charge of all activities regulated in the norm, issuing any technical rules and administrative decisions associated with the regulation, and imposing applicable sanctions for breaches thereof. Regulated operations are expected to comply with national and international standards, including in particular AGA, API, ASTM, NFPA, NTC-Icontec, Retie or similar as found in the petroleum industry. The Resolution recognises that it is subject to all such regulations pertaining to environmental protection and sustainability as well as consultation requirements with communities, health and safety requirements, and labour conditions defined under the ILO Agreements 174 and 181. Parties to an underlying agreement must understand the particularities of the definitions found in Resolution 181495. Colombian law is strict in defining terms and conditions, which when not clearly understood or applied by the interested party can lead to breach of obligations or loss of rights under the underlying agreement. This rigidity has been compounded by the many agencies with oversight over public agencies and officials. The system consists of a prior authorisation and reporting structure. Any activity or operation to be undertaken by the operator of record under an oil and gas contract requires the due filing of documentation and forms before the Ministry of Mines and Energy for them to approve and control activities development under the contracts. There have been recent attempts to simplify this system, easing the operational burdens for contractors. However, the system seeks to ensure that rules are fully respected and that expected activities by an operator are fully undertaken.

In 2013, Decree 3004 of 2013 was issued by the Ministry of Mines and Energy, seeking to define a framework for technical rules. This resulted in the issuance of a further set of rules contained in Resolution 90341 of 2014 from the Ministry of Mines and Energy. In addition to regulations under Resolution 181495, the Resolution 09341 sets forth the technical parameters applicable to the exploration and exploitation of unconventional reservoirs. On the basis of this regulation the government sought to ensure the sustainable development of non-renewable natural resources based on appropriate industry practices. It should be noted that Resolution 09341 of 2014 abrogated Resolution 189742 of 2012, except for the Articles

13 Article 4 of Decree 1056 of 1953.
14 Article 7 of Decree 1056 of 1953.
15 Article 1 of Resolution 181495 of 2009.
16 Article 4 of Resolution 181495 of 2009.
that regulate the ‘operational agreements’ understood as those entered with the operator with the titleholders of mineral rights whenever unconventional reservoirs overlap with mining titles. Pursuant to Resolution 09341 of 2014 the exploration and exploitation procedures not regulated in Resolution 09342 of 2014 shall be governed by the procedures applicable to conventional reservoirs in Resolution 181495. The importance of unconventional hydrocarbon plays was further evidenced by the parallel work undertaken to issue regulations addressing environmental concerns for the exploration of these reservoirs under Resolution 0421 of 2014 of the Ministry of Environment and Sustainable Development and the set of rules and contract drafts for unconventional reservoirs issued by the ANH in Agreement 2 of 2017, which included provisions on that matter that were under Agreement 3 of March 2014. It is notable that the Ministry of the Environment has already issued terms of reference for the exploration of unconventional reservoirs, but the government is still working on applicable environmental parameters for the exploitation of these resources. Therefore, even though there is currently ‘developed’ hydrocarbons regulation for exploration and production of unconventional resources, environmental regulations, which are complementary and must be abided by to conduct hydrocarbon operations, are still behind on how to produce these resources. Environmental licences that allow companies to develop unconventional reservoirs must be granted by the National Environmental Licensing Authority (ANLA), in order to maximise Colombia’s potential in this regard, and attract foreign investment for the industry.

Unconventional reservoir potential has provoked, as in other jurisdictions, debates on fracking, which, as previously indicated, has resulted in Decree 3004 and Resolution 09341 currently being temporarily suspended as an interim measure decreed by the Council of State within a nullity claim presented against these norms. Such a claim argues that the development of fracking activities in Colombia contravenes higher hierarchy norms, such as the sustainable development clause, and, therefore the, precautionary principle (of constitutional order) should be applied thus declaring the nullity of the suspended norms.

As per the transportation regulations, technical regulatory conditions are included under Resolution 72145 of 2014, which regulates the transport of crude by pipelines, and Resolution 72146 of 2014, which defines tariffs for transport via such pipelines. Resolution 72145, in line with Decree 1056 of 1953, recognises that the transport of crude is a public service, which implies that parties undertaking such activity must operate in accordance with regulations applicable to public utilities. After many years of discussion as to whether or not public access was to be granted to oil pipelines, the regulation to ensure free access to parties without any form of discrimination was granted in accordance with the Petroleum Code, defining a set of fair and reasonable transport principles and prices. In furthering the principles of the Code, the government’s preferential right in the transportation of hydrocarbons was reiterated. This right, which is held by the government and exercised through the ANH, in relation to the capacity of the oil pipeline is defined for public pipelines in terms of the right of transport of state crude and with respect to private pipelines for royalty crude. This right extends to 20 per cent of the calculated capacity of the pipeline as constructed. Another aspect that merits comment is the fact that Resolution 72145 required transporters to issue a manual for transportation and to make such manuals public. Transportation manuals must

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17 Article 212 of Decree 1056 of 1953.
18 Article 47 and following of Decree 1056 of 1953.
19 Article 196 of Decree 1056 of 1953.
include a full description of the system, its capacity and connection terms as well as access conditions and applicable tariffs. Colombia holds more than 8,500km, including pipelines and flowlines; 5,467km of pipelines and 3,100km of flowlines.\(^\text{20}\)

The ANH is currently in charge of administering TEA and E&P contracts, leading to considerations of contract rules. Currently Agreement 2 of 2017, issued by the ANH, includes several modifications and defined rules pursuant to which a participating interest in such contracts could be held; it also established contract rules and how to evidence capacities required to be a contractor under an oil and gas contract. With Agreement 2, and its modifications as per Agreement 3 of 2019, the ANH established rules for the award of hydrocarbon blocks, and it also determined the criteria for exploration and exploitation of hydrocarbons in Colombian territory. These criteria include selection of contractors, and management, execution, termination, liquidation, monitoring, control and supervision of E&P contracts.

In 2018, the ANH launched the Permanent Process of Allocation of Areas, which will allow the interested companies to request areas for exploration and production of hydrocarbons continuously, eliminating the need for carrying out bidding procedures for the allocation of areas. Under this process, the interested companies will send their proposal to the ANH, which will then make public the proposal inviting third parties to participate and bid for the allocation.

Key modifications include the determination of contractual principles that pursue the observance of the rule of law, so that contractors have a due process guarantee in their relations with the government, and protection towards parent companies as the government must endeavour to solve its contingencies with the local entities. Also, work programmes are not locked to currency amounts, but to a new points systems that provides benefits as it avoids eventual currency differences, and allows an obligations exchange between the contractor and the contracting party. In addition, the Agreement clearly states the terms, conditions and obligations arising from contracts. It also includes measures to mitigate the effects of falling international oil prices, and limits the rights of operators and non-operators, establishing less stringent participation conditions for the latter, differentiating also offshore and offshore operations, such as conventional and non-conventional.

Nevertheless, Agreement 2 regulates contracts entered into as of 18 May 2017. Prior contracts are still ruled by the Agreements under which they were granted. However, the parties may submit modifications, additions, extensions, assignments and other actions related to the execution of the Contracts, to the provisions under Agreement 2 of 2017.

While the ANH is empowered to enter into direct contracts with interested investors, over the past few years the ANH has developed a bidding system through bid rounds, which attempt to attract a larger number of interested parties in a more competitive environment, where economic proposals ought to be predominant. Bid rounds may, however, define particular additional conditions for certain offers as has been the case of offshore plays or unconventional reservoirs, including specific capacities to be evidenced for said bid round.

Pre-existing direct operations of Ecopetrol or Association Agreements are regulated by different regulations, due to their historic existence. Decree 1895 of 1973 was the previous technical regulation considered applicable, in line with Legislative Decree 2310 of 1974, which assigned the administration of oil and gas to Ecopetrol and its further regulation contained in Decree 743 of 1975.

On the other hand, and considering the regulation of gas supply in Colombia, Decree 2201 of 2003 must be highlighted as a mechanism seeking to promote and ensure national supply of natural gas. Aside from this particular decree, most other regulations have been contained in various resolutions issued by CREG as the regulatory body empowered to ensure operational aspects post-upstream chain:

a in 1999 Resolution 071 defined the Unique Technical Rules for the Transport of Natural Gas;

b in 2010 Resolution 126 defined general criteria for the remuneration of transport of natural gas and the General System for Charges of the National Transport System; and

c in 2015 three key resolutions, 041, 062 and 089, regulated the methodology to calculate the cost of non-exported natural gas, the income for imported natural gas in security generation scenarios and regulated commercial aspects of the wholesale market of natural gas, respectively.

ii Regulation

The Ministry of Mines and Energy is the principal government body in charge of regulating upstream operations in oil and gas. At the contracting level in oil and gas, and other than such association agreements that Ecopetrol held as of 31 December 2003, all subsequent contractual arrangements are executed by the ANH. The ANH’s powers are defined under Decree 1760 of 2003, which created the ANH, and are further developed by Decree 4137 of 2011. While in certain matters there may be doubts as to the delimitation of powers of the Ministry and the ANH, it is clear that the fundamental regulatory powers lie with the Ministry and the ANH is merely an administrator of the non-renewable resources to be developed via TEAs or E&P contracts. As a relevant matter, in early 2013, the ANH and the Ministry executed an inter-administrative agreement that delegated to the ANH certain inspection and regulatory activities. Upon production of gas, the CREG is the governmental body in charge of regulating gas transport and commercialisation. As such, CREG regulates the exercise of activities in energy and gas in order to ensure efficient energy availability and appropriate competitive structure avoiding dominant positions.

Accordingly, there are other governmental entities that have particular roles regarding oil and gas. The Ministry of the Environment is in charge of defining principles and regulations relating to environmental impacts that may be affected by oil and gas operations. Also, there are regional environmental agencies that have the right to issue regulations that must harmonise with national norms. An environmental licence is not required for all exploratory activities. For this permission, regional environmental authorities are the ones authorised to approve these permits. In contrast, when an environmental licence is required, this environmental instrument may only be granted at the state level by the ANLA in accordance with Decree 2041 of 2014, recently compiled in Decree 1076 of 2015. Thus, in certain instances, such as the case where an operator undertakes a seismic acquisition without the need to construct new roads, the operator will only be required to obtain specific environmental permits such as water concessions or discharge authorisations, which will be issued by the regional environmental agencies known as autonomous regional corporations. Moreover, Decree 1076 of 2015 compiled all the environmental applicable rules, including the provisions included in the Decree 2041 of 2014 pertaining to regulatory requirements for unconventional reservoirs and the new terms applicable for the environmental licensing processes.
In the case of offshore activities, entities such as the maritime authority DIMAR and the environmental investigations institute INVEMAR will always play a prominent role. Similarly, when prior public consultation is required in oil and gas exploration and production with indigenous or Afro-Colombian communities, the Ministry of the Interior and INCODER will be involved, issuing the applicable instruments to certify the presence or no-presence of said communities in the area of the project. However, there have been recent discussions involving the emerging communities that were not affected by the project in first instance, but as the project develops, they seem to be affected stakeholders. In this situation, when no agreement has been reached with emerging communities it can cause a major delay in operations, since the courts’ position gives these communities the right of prior consultation, even though certifications of no-presence have been issued by competent authorities. The matter is addressed by the constitutional court in the Judgment T-382/06.\(^21\)

### iii Treaties

With the issuance of Law 39 in 1990,\(^22\) Colombia became a party to the 1958 New York Convention.

Furthermore, the recently issued Law 1563 of 2012 established a complete set of rules on national and international arbitration. The regulation clearly indicates that arbitral rulings rendered abroad can be recognised and executed in Colombia in accordance with the applicable regulations.

Among the various commercial treaties recently entered into by Colombia and those that intend to further commercial relations, there have been many free trade agreements negotiated in the past few years. These treaties include:

\(a\) the Free Trade Agreement between Colombia and Peru and the European Union and its Member States as approved by Law 1669 of 2013;

\(b\) the Free Trade Agreement between Mexico and Colombia as approved by Law 1457 of 2011;

\(c\) the Free Trade Agreement between Canada and Colombia as approved by Law 1363 of 2009; and

\(d\) the Free Trade Agreement between Colombia and the United States of America as approved by Law 1143 of 2007.

In addition, Colombia has entered into various bilateral investment treaties, including but not limited to, Peru, Switzerland, China, Spain and Japan.

To date Colombia has entered into double taxation treaties with Argentina, Brazil, Canada, Chile, the Czech Republic, France, Germany, Italy, India, South Korea, Mexico, Portugal, Spain, the United States, Venezuela and the member states of the Andean Pact Community, and it is seeking to increase the jurisdictions with which it has these types of arrangements.


III LICENSING

Colombia has three types of underlying agreements that grant title to the exploration and production of oil and gas. These contractual structures are the association agreement, which remains in force between Ecopetrol and such parties with which it had entered into or renewed a contract prior to the end of 2003, and the TEA and E&P contracts as executed by interested qualified parties with the ANH. Access to association agreements may only be done via Ecopetrol on the basis of its grandfathered rights. Access to TEAs or E&Ps is typically done via public open competitive mechanisms. These require public invitation, prior qualification of proponents and the ANH objectively selecting on the basis of offers, specific terms of reference of the corresponding bid round and Agreement 2 of 2017. However, note must be made that this Agreement determines that contracts subscribed before Agreement 2 was issued will be regulated under Agreements in place at the date of their execution. Aside from the open competitive mechanism there is the competitive closed procedure and the direct allocation. The first is based on an invitation to a specific set of proponents or contractors that *ex ante* meet the conditions expected by the ANH and again the ANH selects the winning bid from the select group based on offers, the specific terms of reference of the corresponding bid round and Agreement 2 of 2017 or that Agreement applicable at the execution time. In the latter scenario, direct negotiation is always considered an exceptional process subject to the approval of the ANH board of directors, requiring express conditions to undertake this type of process, by invitation or contractor proposal and subject to Agreement 2 of 2017.

In accordance with Agreement 2 of 2017, interested parties must meet the five minimum capacity requirements: legal; financial; technical-operational; environmental; and social responsibility. Legal capacity can include time of existence and corporate purpose definition. Financial capacity relates to the economic solvency that an investor is expected to have in order to comply with its obligations under the corresponding agreement. The technical and operational capacity of the proponent is tied to production and reserves of proponent, including the technical team available to undertake the proposed contractual commitments. The environmental capacity refers to a set of principles, rules and best practices to which the proponent commits and is credited with having. Lastly, there is the social responsibility component, which includes work ethics, respect of the state, workers and community, and a social licence to operate, including past practices and best practices that the proponent can effectively demonstrate to have set in place in its organisation.

Exploration and production contracts as state contractual concessions have an exploration period of two to nine years and a production period of 24 to 30 years, according to Agreement 2 of 2017. Each period is divided into specific phases with specific work commitments in turn composed of a compulsory programme and an additional programme that the proponent will have typically offered, and both terms may be extended provided certain conditions are met under the contract.

It is important to note that capacities to be evidenced by proponents for unconventional reservoirs are provided under Agreement 2 of 2017. Under this Agreement, production, reserves and economic solvency capacities are different from those provided for conventional resources.
As per the economic rights under E&P contracts, they will include royalties based on percentages varying from 8 to 25 per cent of production calculated per field. In addition further payments may be triggered when field production exceeds 5 million barrels and the West Texas Intermediate has varied in relation to predefined indexes. Similarly, subsurface rights are to be paid during exploration and the ANH will expect social investments and technology transfer fees under the underlying agreements.

Breach of the underlying agreement can fundamentally be triggered by a failure to comply with economic obligations, timing requirements or work programme commitments.

IV PRODUCTION RESTRICTIONS

Colombian regulations do not limit the terms of production of oil and gas. On the contrary, rules seek to restrict loss of product, to ensure maximum production. In turn, the ANH receives the royalties required of the contractor, which can also be paid in kind. The contractor holds the rights to production after the payment of royalties and can dispose of hydrocarbons in the local or international market. High fees may apply in certain instances, but this in itself does not restrict production. Refining can require (as is also the case of gas required for domestic supply) that contractors comply with the preferential duty to supply local markets. A further rule is found under the Petroleum Code, which indicates that in the event that the royalties received by the government are insufficient to supply local requirements of oil derivatives, at the government’s request, contractors will be obliged to offer for sale a quantity that, when added to the royalty, does not exceed 50 per cent of the total production.

V ASSIGNMENTS OF INTERESTS

Limitations to assignment of interest are in turn restricted to complying with the same conditions and capacities that allowed the assignor to acquire the corresponding participating interest or any condition as operator of record. No preferential right exists in relation to the government, but the ANH must approve all transfers in advance. Certain recent regulatory developments require antitrust filings when certain thresholds are met and when competition restriction is evident. To the extent that capacity conditions are met by the assignee, assignment should generally take place. However, it must be highlighted that guarantees in place for the compliance of obligations under contract must be renewed or provided new by assignee, especially to comply with exploration work programmes. Assignments have taken more time than expected to be processed by the ANH and farmees and farmers should provide for this particular situation in their contractual arrangements. When assigning interests, particular attention should also be given to timing with assignment of environmental licences and permits.

23 Article 16 of Law 756 of 2002. Note that unconventional reservoirs under Law 1530 of 2012 have a benefit equivalent to 40 per cent reduction in the tariff applicable to conventional resources. The ANH defined the methodology for liquidation of royalties for oil and gas during 2013 in Resolutions 411 and 412 of 2013, respectively.

24 Reference can be made to Decree 1073 of 2015.
VI TAX

Operators undertaking onshore activities in Colombia will be fully taxed as any other Colombian national. However, and as an incentive seeking the promotion of offshore oil and gas activities, the Colombian Ministry of Trade, Industry and Tourism and the Ministry of Finance issued Decree 2147 of 2016, which allows the declaration of permanent offshore free trade zones. In a nutshell, the free trade zones regime allows companies operating offshore to benefit from a significant tax reduction\(^\text{25}\) and a more favourable customs regime. Finally, the Petroleum Code sets forth that municipal and department taxes shall not apply to the exploration and production of oil and its transport as well as in the construction of refineries or pipelines.

The applicable Colombian fiscal regime consists of a combination of the following taxes:

- **a** corporate income tax (CIT): 33 per cent tariff;
- **b** corporate income tax surtax: 4 per cent tariff for 2018. The corporate income tax rate for Colombian entities is 33 per cent (as of fiscal year 2018). In fiscal year 2018 the CIT rate will be 33 per cent + 4 per cent = 37 per cent, and as of fiscal year 2019 – and following – it will be 33 per cent;
- **c** industry and commerce tax ICA: ICA taxable event is the exercise or performance, directly or indirectly, of commercial, industrial or service activities within the jurisdiction of a municipality. ICA tax rates vary from 0.2 per cent to 1.2 per cent, depending on the nature of the activity to be performed in the respective municipality. 100 per cent of the ICA paid is deductible for income tax purposes;
- **d** bank debit tax: Currently Colombia has in place a bank debit tax. This tax is withheld by the financial authorities and has a taxable base of 4 per mille applicable on any withdrawal or transfer made from savings and checking accounts. 100 per cent of the paid tax is deductible for income tax purposes;
- **e** VAT: All goods and services purchased locally are subject to a standard rate is of 19 per cent. The standard rate applies to all supplies of goods or services, unless a specific provision allows an exclusion from VAT or the application of a reduced rate; and
- **f** royalties.

In addition, all goods and services purchased locally are subject to 19 per cent VAT.

<table>
<thead>
<tr>
<th>Tax</th>
<th>Definition – scope</th>
<th>Level</th>
<th>Tariff (per cent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Income tax</td>
<td>The remuneration of the factors of production, all net income, that increase the equity*</td>
<td>National</td>
<td>33</td>
</tr>
<tr>
<td>Income tax surtax</td>
<td>Established in 2018, the surtax is a tax surcharge for the income tax</td>
<td>National</td>
<td>4 (2018)</td>
</tr>
<tr>
<td>Industry and commerce</td>
<td>The remuneration generated from service, industrial and commercial activities carried out in the municipality</td>
<td>Regional</td>
<td>Between 0.2 and 1.2</td>
</tr>
<tr>
<td>Bank debit tax</td>
<td>Any withdraw or transfer made from savings and/or checking accounts</td>
<td>National</td>
<td>0.4</td>
</tr>
<tr>
<td>VAT</td>
<td>All goods and services purchased locally</td>
<td>National</td>
<td>19</td>
</tr>
</tbody>
</table>

* Foreign companies that do not have a permanent establishment in Colombia should pay income tax of 40 per cent.

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\(^{25}\) CIT tariff: 20 per cent and an exemption from payment of import duties and taxes on the entry of goods, such as raw materials, packaging material and machinery, from the rest of the world to the free zone.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In accordance with applicable regulations, only listed oil and gas exploration and production activities are required to hold a prior environmental licence. Furthermore, only the ANLA is competent to permit oil and gas exploration and production when an environmental licence is required. Activities not requiring an environmental licence may require local environmental permits associated with the use of specific natural resources on a case-by-case basis. Operators must carefully review restrictions on operations derived from the classification of protected or excluded areas, zoning regulations and the growing number of basin management plans and programmes. Under Colombian law, environmental authorisations are not considered acquired rights and may suffer modifications or limitations throughout the course of a project.

Environmental licences are composed of the environmental impact assessment, the environmental management plans, the contingency plan and the abandonment and decommissioning plan. Operators are required to provide guarantees ensuring that decommissioning will be appropriately carried out. This is a requirement both under environmental laws and under the underlying agreements. Accordingly, for decommissioning purposes in underlying agreements, contractors are obliged to establish a decommissioning fund to guarantee availability of resources to develop the decommissioning programme. This fund may be done through any economic instrument approved by the ANH (i.e., trusts, bank guarantee). This provision is mainly determined under contract, where ANH determines the conditions of the decommissioning fund.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Foreign nationals are granted the same civil rights as Colombians. Other than limitations under the Constitution or other laws, foreign nationals in Colombian territory are granted the same guarantees that Colombians have.

Foreign companies wanting to undertake oil and gas exploration and production in Colombia must set up a branch duly recognised for such purpose. Of particular interest is the fact that Law 10 of 1961 extended this same obligation to foreign service providers in the oil and gas sector.

In lieu of establishing a branch, foreign investors may, of course, incorporate a subsidiary. The timing required for the incorporation of a subsidiary or a branch office is generally similar. Other than for legalisation of documents required to be processed locally for registration purposes, most of the time required to initiate operations is associated with the Ministry of Energy and ex post recognition that all criteria have been effectively met. While not a sophisticated procedure, it may take two to three months to start the two-to-three-week process to establish the branch or incorporate the subsidiary.

27 Article 100 of the Colombian Political Constitution.
28 ibidem.
29 Article 10 of Decree 1056 of 1953.
30 Article 3 of Law 10 of 1961.
ii Capital, labour and content restrictions
No minimum capital requirements are necessary for the branch or the subsidiary. Evidently, contractual requirements will ultimately require minimum work programme obligations to be met. Exchange regulations fully protect foreign investment and in the case of oil and gas, E&P operators may access the special exchange regime that allows parties to make and receive payments in a foreign currency. Foreign investors must, however, strictly follow applicable exchange regulations to avoid fines ranging up to 200 per cent of the value of the invested or channelled amounts.

No limitations exist in Colombia as to the hiring of foreign nationals, apart from visa and regulatory requirements that have to be met. However, it is important to consider that the underlying agreements and environmental licence will typically promote contracting local labour to the extent available at this level. Decree 2089 of 2014 set forth specific conditions requiring that local labour be preferred for unqualified labour in field operations.

iii Anti-corruption
Colombian oil and gas practice had led to increased knowledge of FCPA rules as well as the UK Bribery Act. In line with these international regulations and seeking to restrict any issues of corruption to the furthest extent possible, Congress issued Law 1474 of 2011, which has become the anti-corruption codex. Similarly, and even before this regulation had been issued, Law 412 of 1997 had already approved the Inter-American Convention against Corruption.

IX CURRENT DEVELOPMENTS
The election of Ivan Duque as president of Colombia for the 2018–2022 term presents an encouraging scenario for the hydrocarbons industry. President Duque is a supporter of an increase in the exploration of offshore hydrocarbons. Another of his proposals is the evaluation of possibility of exploitation in desert areas, sparsely populated or without population and without bodies of water, and in more populated areas to seek consensus between companies, the government and communities.31 Additionally, he has pronounced on several occasions regarding the need for legal security for the investor, proposing the: (1) limitation to the tutela constitutional action in order to prevent its abuse; (2) unification of rulings issued by the highest courts; and (3) regulation for popular consultations regarding projects of national interest, such as hydrocarbons and mining.

It is also important to analyse and consider the different implications and effects that the implementation of the peace agreement will have in relation to the hydrocarbons sector. It is worth mentioning that, even though in the peace agreement there is no explicit reference to the hydrocarbons sector, it is possible to highlight implications for this sector. To this effect, it is worth noting that the ANH determined that the number of blocks for oil and gas exploration and production will increase in coming years with the signing of the peace agreement. Also, the new strategy of the Ministry of Mines, in association with the ANH, seeks to extend territorial peace by reaching social agreements between the local communities and the hydrocarbons sector, in order to reduce the strain on stakeholder relationships and

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31 www.portafolio.co/economia/las-propuestas-que-mas-separan-a-duque-y-petro-518102.
thus promote peace. However, it should be noted that oil and gas transportation industry has had a rough year, as the ELN guerrilla group has been constantly bombing pipelines in the country.

With the favourable conclusion of the peace process, Colombia is facing a great variety of possibilities and opportunities that must be regarded as advantages that include new possibilities and opportunities for the recovery of the hydrocarbons sector in Colombia, which could have an important impulse as a consequence of the peace agreement achieved by the government, but recognising also that it is just one step of many required for the oil and gas industry to take off again in the country.

Besides that, two additional considerations must be made: (1) a new offshore model contract was issued that aims for the development of new hydrocarbons blocks in Colombian oceans (this contract has an arbitral clause favourable to investors); and (2) the aforementioned modification of Agreement 2 of 2017 through Agreement 3 of 2019.

Lastly, it is important to mention that current Colombian Petroleum Code constitutionality has been challenged, on the basis that Articles 3 (partially), 8 (partially), 11 (partially), 27 (subsection 3 partially), 56 (partially) and 57 (partially) of the Code establish that certain differences as determined under the Petroleum Code (i.e., price arrangement, employee competence and production capacity of wells) must be resolved obligatorily through an expert opinion.

The claimant concerned alleges that this interpretation is unconstitutional provided that under the Petroleum Code decisions of experts are attributed with material force of judicial sentence with the force of res judicata, following a procedure analogous to arbitration. This violation of the Constitution is based on the conditions under which individuals can be invested to administer justice (arbitrators), due process violation, the right to the second instance and access to the administration of justice, considering that parties may elect from different mechanisms of dispute resolution.

This claim is still to be resolved, but if the Constitutional Court considers that these norms actually are unconstitutional, affected parties under challenged clauses may elect to resolve differences through different mechanisms besides expert opinions.
Chapter 8

DEMOCRATIC REPUBLIC OF THE CONGO

Olivier Bustin and Luiza Savchenko

I INTRODUCTION

The Democratic Republic of the Congo (DRC) is the most populous French-speaking country in Africa and a very attractive prospect for investors owing to the richness of its natural resources, such as cobalt, copper, cassiterite, gold, manganese, diamond and petroleum.

In numerous official and unofficial speeches, it has been emphasised that the DRC has an important upstream oil potential, in particular in three sedimentary basins: the Coastal Basin (located in Kongo Central, extending offshore past the Congo River estuary), the Central Basin and the western branch of the East African Rift. Today, the production is around 25,000 barrels per day. However, experts estimate it could go up to 100,000 barrels per day, once some of the blocks in the east of the country have entered into a production phase. Despite such wealth, the DRC is struggling to sufficiently develop its oil and gas industry upstream (prospecting, exploration and exploitation) and downstream (refine, transport, storage of petroleum products, supply of petroleum products, import and market petroleum products).

II LEGAL AND REGULATORY FRAMEWORK

Since its independence in 1960, the DRC has gradually put in place its oil and gas legal framework. In the Constitution of 2006, the DRC affirms its permanent sovereignty, in particular on the Congolese ground, subsoil, waters and forests, as well as air spaces and territorial sea.

i Domestic oil and gas legislation

The previous legislation regulating activities in the mining and hydrocarbon sector are Act No. 67-231 of 11 May 1967, which was repealed by Ordinance-Law No. 81-013 of 2 April 1981 (the 1981 Ordinance-Law), which in its turn was repealed by Law No. 15/012 of 1 August 2015 (the 2015 Law), since over time, several provisions of the 1981 Ordinance-Law became obsolete and the hydrocarbon legislation needed revising to provide more transparency.

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1 Olivier Bustin is managing international adviser of the OHADA jurisdictions practice and Luiza Savchenko is senior international adviser of the banking and finance practice at Vieira de Almeida. The authors would like to acknowledge Mariame Tolno’s invaluable assistance in preparing this chapter.
The 2015 Law gave the hydrocarbon sector a new leap of life, bringing several innovations, and Decree No. 16/010 of 19 April 2016 (2016 Decree) consolidated those modifications and conditions regulating the hydrocarbon sector.

Prior to that, the Regulation of Exchange of 28 March 2014 (the Exchange Regulation), entered into force in September 2014 and ensures some exemption rules for petroleum companies.

Lastly, it is noteworthy that Law No. 11/009 of 09 July 2011 on fundamental principles relating to the protection of the environment sets out certain requirements and procedures that are relevant for those in the oil and gas industry.

**ii Regulation**

The Ministry of Hydrocarbons is responsible for development, management and implementation of the national policy on the institutional framework for hydrocarbons in the DRC. The mission is carried out through its technical and administrative body, the General Secretariat. The decisions of the Minister of Hydrocarbons must be further approved by the Council of Ministers, the body competent to approve concessions contracts.

The intervention of the Minister of Finance is necessary for the collection of taxes, duties and fees related to hydrocarbon activities.

The state participates in upstream and downstream hydrocarbon activities through the national wholly owned company acting on its behalf (Sonahydroc), which is entitled to a non-assignable participation of at least 20 per cent. Sonahydroc engages in these activities with another company awarded the hydrocarbon licence (the contractor) through a joint venture agreement, governed by the Congolese law, without creation of a separate legal entity.

The DRC has established a public institution to save, manage and delegate the funds for future generations, from a portion of the state’s profit from the oil activities.

**iii Treaties**

The DRC is a member of several conventions, protocols and international organisations, including the following:

a International Maritime Organization;

b International Convention on Oil Pollution Preparedness, Response and Cooperation (OPRC) of 1990, ratified by the Law No. 11/016 of 15 September 2011;

c United Nations Framework Convention on Climate Change;

d Kyoto Protocol;

e Organization for the Harmonization of Business Law in Africa (OHADA), since 2012 (in this regard, it is worth highlighting that investors can refer to OHADA arbitration, to the Common Court of Justice and Arbitration (CCJA) or another arbitration court. The CCJA judge is competent to grant exequatur to arbitration sentences to be enforced in the DRC); and

f Common Market for Eastern and Southern Africa (COMESA) to encourage private investment and reduces obstacles for the free movement of persons, goods, services and investment in COMESA area.

Moreover DRC has signed a trilateral agreement with COMESA, Southern African Development Community and East African Community, encouraging, among other things, free movement of investments in the member countries.
The DRC has entered into bilateral investment treaties with other countries, such as France, Germany, Switzerland, the United States, and double taxation treaties with South Africa in 2005 and Belgium in 2007.

Lastly, the DRC has ratified the International Centre for Settlement Investment Disputes (CIRDI), the impartiality of which is viewed as a guaranty for the investments in the DRC, as well as the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards (New York Convention).

III LICENSING

i Tendering procedure

Pursuant to the 2015 Law, the Minister of Hydrocarbons is responsible for granting the authorisations based on a specific public tender procedure, which is different from the public procurement procedure in terms of selection criteria, purpose of the contract, managing authority, etc.

Previously, under the 1981 Ordinance-Law, mineral rights for hydrocarbons were granted by a Petroleum Convention, which provided the conditions for the exercise of hydrocarbon rights; it also gave free rein in negotiating the terms of the agreements, including tax and customs provisions, but lacked transparency in granting permits since there were no tender procedures in place.

The 2015 Law provides in its implementing decree, that the Minister of Hydrocarbons shall submit to the Council of Ministers a file containing certain criteria, including the technical and financial, to be met by the candidates. The Minister of Hydrocarbons shall then establish an ad hoc committee to organise and overview the tender for the allocation of hydrocarbon rights. As a general rule, any oil and gas company can apply to participate in the tender, unless the tender is restricted by the Council of Ministers.

Applications that do not meet the criteria indicated in the request for expression of interest are rejected and the applicants are notified in this respect. Applications that meet the criteria are preselected and the applicants receive the preselection notification. The Minister of Hydrocarbons prepares a final report of the tenders and submits it to the Council of Ministers.

The preselected companies are provided with specification books for a non-refundable fee (the amount is indicated in the letter of invitation). Such specification books contain everything necessary for the potential oil contract, including an invitation letter, technical offer, financial offer and terms of reference.

After a series of verifications, the ad hoc committee draws up and submits the evaluation report to the Council of Ministers. The Minister of Hydrocarbons notifies the bidding companies of its decision to select or reject 15 days after the evaluation report is submitted. Non-selected companies may appeal the decision. The tender is followed by the negotiation with an inter-ministerial commission composed of experts from the Ministries of Hydrocarbons and Finance and, upon agreement, signing the contract.

ii The types of petroleum contract in DRC

The production sharing contract

The production sharing contract provides for the sharing of hydrocarbon production between the state and the company or group of companies in which state-owned Sonahydroc holds shares. Sonahydroc first enters into a joint venture agreement with other private companies under Congolese or foreign law. Under the 2015 Law, the participation of Sonahydroc of at
least 20 per cent is compulsory and non-assignable, unlike under the 1981 Ordinance-Law, when it was optional. The production sharing contract must contain information relating to the block, duration of the various phases, commercial, socioeconomic and environmental obligations of the parties, any renegotiation clauses by the way of amendments, bonus sharing mechanics and termination events. The production sharing contract covers two phases: exploration phase and operating phase.

The block service contract

The block service contract allows a third party on behalf of the state or Sonahydroc to carry out petroleum activities at its own risk and expenses. Such third party may be financed by the state in the case of a contract for technical assistance in realisation of the petroleum works for the development of a block for adequate remuneration in cash. The block service contract may take the form of a service-at-risk contract or a technical assistance service contract, and, among other things, determines the execution terms and applicable tax regime. As a general rule, the exploration and operating expenses are paid without interest; however, expenses related to the development investments are remunerated with interest. The block service contract also has two phases: exploration and exploitation.

Typically, a special operating committee is created for each contract, which is responsible for examining and validating the orientation, programming and execution of petroleum works.

The penalties for breach of contract obligations

For upstream activities, the contractor's breach of obligations may result in:

a invalidity of the contract, in particular, if it was assigned without prior approval of the Minister of Hydrocarbons;
b termination of the contract in accordance with the terms of the contract, provided that the Minister of Hydrocarbons sends 15 days prior notice;
c refusal to renew the right; or
d compensatory allowances of at least 35 per cent of the costs of the unrealised works.

The contractor may also renounce its rights, for example, abandoning the works, which will be ascertained by the Minister of Hydrocarbons.

IV  PRODUCTION RESTRICTIONS

The DRC in its 2015 Law and 2016 Decree imposes certain restrictions with respect to permits granted to companies in oil and gas industry, as discussed below.

The prospection permit is non-assignable and non-transferable and valid for a period of 12 months, renewable only once for a period of six months. To obtain a prospecting permit, the contractor shall fulfil all technical and financial criteria of the invitation to tender, submit to the Minister of Hydrocarbons (with a copy to the Secretary General) an application form together with the specifications (as set out by the Minister of Hydrocarbons) and environmental impact assessment subscribed to the specifications, drawn up by the Minister of Hydrocarbons, and present an environmental impact assessment. Generally, in the case of an invitation to tender, the beneficiary of a right to prospect is preselected if he or she has already complied with the specifications.

The exploration right is granted for a period of three years, except for the exploration in the Sedimentary Basins, where the duration of the permit is four years from the date of entry.
into the relevant contract, and is renewable twice for the same period (i.e., three years for blocks category A and B, and four years for blocks category C and D), which can be further extended for six months. The exploration permit may be transferred (partially or totally) or transmitted with the prior approval of Sonahydroc. For any assignment, Sonahydroc has a pre-emptive right.

The exploitation right is granted for a maximum duration of 20 years, renewable once for a maximum period of 10 years, and is transmissible or transferable under the same conditions. Capital gains on disposals are taxable.

All financial and technical documents of all contractor’s entities relating to the petroleum works are subject to periodic audits by the Ministry of Hydrocarbons, with 30 days’ prior notification to the contractor before any audits. An additional period of 20 days may be granted upon reasonable request by the contractor. The contractor is required to keep its accounting and financial records up to date, in French and in Congolese francs or US dollars.

Any petroleum company operating in the DRC is also subject to certain obligations, including the obligation to ensure the conformity of its installations, obtain an insurance policy for the installation of its equipment, acquire the necessary means to meet the demand and develop means in order to respond to the increase in national demand, and realise financial conditions in priority with Congolese land and banking institutions.

For each downstream petroleum activity, companies must obtain the following authorisation from the Ministry of Hydrocarbons:

a) refining contracts to be entered into by the companies and the government, with prior approval of the Ministry of Hydrocarbons (with a copy to the Secretary General) and payment of a fee;

b) for transportation and storage of the product, the licence for a volume of petroleum product quantity more than 10m³ (for quantities less than 10m³, the Secretary General grants the licence according to Articles 152.2 and 152.4 of the 2016 Decree); and

c) supply contracts are estimated every year based on the volume, and are granted for a renewable term of four years (renewal is unlimited). Petroleum products are priced on the basis of the Oilgram Price Report (Global Market Report-Platts) or another review specialised in petroleum price determination (Article 187 of the 2016 Decree). Only supply contractors are permitted to export or import petroleum products from a foreign territory from or to the DRC territory.

The import and marketing of petroleum products permits are granted for a renewable term of 12 months, including:

a) a marketing permit to purchase petroleum products acquired from an importer,

b) an import permit is a title granted for self-consumption; and

c) an import and marketing permit allows import and sale by the same operator of petroleum products.

Any breach of obligations in the exploration or exploitation phase is punishable by fines fixed by ministerial decree and in accordance with the terms and conditions of the contract.

For downstream activities, the breach of obligations is punished by withdrawal of exploitation rights and refusal of its renewal. Civil law sanctions will also apply.

The contractor may also be subject to certain penal sanctions if it acts in a way as to pressure or cause the officials of the Ministry of Hydrocarbons to act in violation of the law.
V ASSIGNMENTS OF INTERESTS

Contracts settled before the entry into force of 2015 Law are executed under the previous law, however, any renewal of such contract, including the assignment of interest, is subject to the 2015 Law.

The state has the power to grant the exploitation permits and its renewal. A notification is sent to the person concerned and, if the permit is rejected or not renewed, an appeal is always possible.

VI TAX

From tendering period to the work completion, the contractor shall be subject to the payment of several costs, in particular the cost of providing the specifications, appraised fees, costs of transporting petroleum products, environmental audit fees in the event of an assignment, costs associated with environmental damage, persons and their property, at the renewal fee.

Without prejudice to other taxes, determined by law, the contractor and its subsidiaries, consultants and subcontractors shall be exempted from the corporate income tax. The Tax Directorate and Custom Department issues the exemption certificate to these parties.

i Taxes

Tax for exploration

The registration fee for an exploration permit is determined by the Ministry of Hydrocarbons according to the fiscal zone, as described below. The same system of taxation is applied for the renewal of exploration licence.

VAT is free in the exploration phase.

Assignment rate is 40 per cent. There are no exemption rights, obligations and responsibilities before the assignment enters into force.

Tax for exploitation

The renewal fee for an exploitation permit is determined according to the production.

VAT is payable in the operation phase.

Assignment rate is 30 per cent. There are no exemption rights, obligations and responsibilities before the assignment enters into force.

Other customary royalty and costs

For general upstream activities, the blocks are categorised into four tax zones because of their geological and environmental characteristics: zone A, zone B, zone C, zone D.

For any petroleum activity, the contractor shall be subject to the following taxes, duties, fees and charges:

Royalties are paid in kind or in cash to the state by the contractor, levied on the amount of hydrocarbons produced after certain deductions. Rates vary by the tax area and may not be lower than the following:

a tax area A at 12.5 per cent;
b tax area B at 11 per cent;
c tax area C at 9.5 per cent; and
d tax area D at 8 per cent.
The state’s share of the oil profit is fixed according to a progressive scale that shall not be less than the following:

- **a** tax area A at 45 per cent;
- **b** tax area B at 40 per cent;
- **c** tax area C at 40 per cent; and
- **d** tax area D at 35 per cent.

The state’s share of the excess oil is the excess of the stop-over recoverable costs during the contract. The cost of oil is the fraction of production withheld by the contractor as a reimbursement of costs incurred. The following costs also apply:

- **a** the cost stop is the percentage of hydrocarbon production limiting the level of recovered costs incurred by the contractor;
- **b** the superficial fee is a fixed fee payable annually in Congolese francs equivalent to US$100 per square kilometre for an exploration phase and US$500 per square kilometre for an exploitation phase, and is non-refundable;
- **c** the statistical tax;
- **d** payment for any administrative document;
- **e** the exceptional tax on remuneration of expatriate staff;
- **f** the professional tax on the remuneration of nationals;
- **g** internal value-added tax on local consumption in the operating phase;
- **h** tax on any form of assignment of rights or interests during exploration and exploitation phases; and
- **i** at the time of the contract signing, from the rider adds to the renewal of the exploration and exploitation rights, a non-refundable fee is paid to the state by the contractor during the first production. The amount of the fee is defined by ministerial decree and negotiated by the contractor.

**Customs**

Export and re-export of goods such as core samples, raw oil samples, oil and chemical samples, as well as goods imported under the franchise regime, are free of customs duties and taxes.

The contractor shall also benefit from full exemption from duties and taxes on the export of hydrocarbons produced in the DRC.

The contractor shall also benefit from a customs exemption for the importation of goods exclusively used for the petroleum operations in respect of which they are imported.

The contractor must provide a performance guarantee in a first-class bank approved by the state.

Capital gains on disposal are taxable. The exchange rate is determined by the DRC Central Bank.

**VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING**

The contractor shall establish an emergency plan to prevent the pollution of petroleum products and is also required to present the environmental and social impact assessment with its rehabilitation plan.

A special provisional fee for possible abandonment work is set up at the operating phase and is paid into an escrow account opened with the DRC Central Bank. This fee cannot be seized or pledged. The cost of abandonment is a cost of the site restoration on completion.
petroleum operation, and is recoverable for costs providing petroleum activities. In the event of abandonment, the contractor must submit an abandonment plan for approval to the Minister of Hydrocarbons. At the end of restoration works, the Minister of Hydrocarbons grants a certificate of execution to justify the end of rehabilitation works.

As a general rule, exploration or exploitation is prohibited nearby the DRC’s towns and villages, wells and water pipes, public buildings and public works, places considered sacred, communication routes and civil engineering structures, unless the concessionaire and the owners or their beneficiaries sign a prior agreement with an agreed compensation.

The contractor may be held responsible for any environmental damages that are caused by activities to persons or the environment and subject to penalties, as well as civil and criminal liabilities.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Incorporation and investment

Any foreign company wishing to enter into a production sharing or block service contract must establish a company under Congolese law for the purpose of carrying out exploration and exploitation activities.

The Exchange Regulation provides certain measures for petroleum companies to control the production, sale and import of oil products. The contractor is allowed to export its entire production, but must sign a declaration model (EB) with an approved bank in the DRC. A beneficiary-company of exploitation and production permits shall sign a specific model of import declaration (IB) for importation of goods with an approved bank.

In certain cases, companies can hold an account in foreign currency in any national bank. They can also hold an account in a foreign international bank to manage the funds that they are allowed to hold outside the DRC.

Companies should pay to the DRC Central Bank or any mandated person fees at the rate of 0.2 per cent for all payments made to or from outside the country.

ii Social obligations

The contracting company is subject to the provisions of Congolese labour law in relation to its staff and is bound by certain social obligations, in particular, contributing annually to the training of administrative agents in the hydrocarbons sector. As a general rule, hiring priority is granted to nationals with equal competence over foreigners.

iii Employment restrictions

Subject to specific derogations, for specific occupational categories in the business sector, the labour administration ensures compliance with the rule that all employers are prohibited from having foreign nationals form more than 15 per cent of their workforce. However, if there is an exemption provided by bilateral treaties with other countries, investors from these countries may not face such restrictions.

In case of employment of foreign persons, the National Committee decides on the issue and renewal of work cards for such employees. This card-issuing operation is taxable.

Subcontracting or outsourcing the works to other companies is permitted and priority shall be given to Congolese companies.

Legal entities are subject to the provisions of Congolese law and the norms and practices in force in the international petroleum industry.
IX  CURRENT DEVELOPMENTS

Despite currently having few petroleum companies in the operational phase, the Congolese oil and gas sector is evolving, and the commitment to establish a stable legal and fiscal policy is a key factor that will enable the country to attract more investors. Introduction into the legal framework of an exemption from corporation tax for contracting companies and their subsidiaries (Article 254 of Decree No. 16/010 of 19 April 2016), exemption of certain export and import activities are measures to boost investment in the oil and gas industry. The transparency policy aimed by government should also encourage investors in this regard.

In a nutshell, the DRC is a big country with huge natural resources from mining and oil, and investing in the DRC can be complex but not impossible. A thought-through approach and well-structured legal advice will help to manage sound petroleum investment.
Chapter 9

DENMARK

Michael Meyer

I INTRODUCTION

There are oil and gas deposits in the Danish part of the North Sea, and at the time of writing there are in total 19 oil or gas-producing fields. The first concession (the Sole Concession) was granted to A P Møller-Maersk back in 1962 and covered the entire Danish area. The Sole Concession was amended by agreement with the Danish government in 1981, and areas are gradually being handed back to the Danish state.²

The Danish Energy Agency (DEA) has finalised eight rounds³ of applications to obtain licences to explore for hydrocarbons in the North Sea. The seventh round concluded in 2016 resulting in the award of 16 new licences. An eighth round was initiated in 2018, with areas offered for licensing in the Central Graben and in the adjoining areas further east bounded at 6° 15’ E longitude. The round concluded on 1 February 2019, and five applications from four companies are currently being processed by the DEA. According to the DEA, it is the aim to initiate additional rounds of applications every second year with the next, ninth round planned for 2020.

In addition to the licensing rounds, Danish legislation has since 1997 foreseen an open-door procedure for unlicensed areas east of 6° 15’ eastern longitude.⁴ Applications may be submitted at any time between 2 January and 30 September of each year. Neither the licensing rounds nor the open-door procedure contain nationality requirements for obtaining or participating in a licence.

The Danish state participates through the independent entity Nordsøfonden in all licences granted since 2005 whether in a licensing round or through the open-door procedure with a 20 per cent stake. In addition, Nordsøfonden participates with a 20 per cent stake in the Sole Concession.

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¹ Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleague, assistant attorney Hans Nikolaj Amsinck Boie, for his assistance with this chapter.
² For further information see the Danish Energy Agency’s web page www.ens.dk (partly in English).
³ The first round took place in 1984, the second in 1986, the third in 1989, the fourth in 1995, the fifth in 1998, the sixth in 2006, the seventh in 2016, and the eighth round was concluded in February 2019. See further www.ens.dk.
⁴ Following the Danish government’s decision in February 2018 to stop future investigations and drillings onshore and in inland waters, the procedure is limited to the North Sea east of 6° 15’ eastern longitude; see Section III.
⁵ Nordsøfonden (the North Sea Fund) is established by law, see Act No. 587 of 24 June 2005 on a public fund to manage the state’s participation in hydrocarbon licences and a public entity to administer the fund.
⁶ Nordsøfonden does at the time of writing not participate in licences 7/86 and 1/90 (Lulita), 7/89 (South Arne), 4/95 (Nini), 6/95 (Siri) 5/98 (Hejre) and 16/98 (Cecilie).
Denmark has been a net exporter of energy since 1997 and was until recently expected to be largely self-sufficient in oil and natural gas. However, pursuant to the DEA’s latest forecast, Denmark is only expected to be self-sufficient with regard to natural gas. For 2019, the DEA anticipates an oil production of 6.1 million m³ and a production of natural gas (sales gas) of 2.4 billion normal cubic metres (Nm³). Denmark’s reserves of oil are as of 1 January 2019 estimated to 128 million m³ and of sales gas to 70 billion Nm³, both figures including contingent resources. As indicated, the DEA’s latest forecast for Denmark’s self-sufficiency in oil foresees that Denmark will no longer be self-sufficient. According to previous forecasts, Denmark was expected to be a (marginal) net exporter of oil for a number of years, but the forecast has lately been reduced due to reassessments following new data, production experience and postponed commissioning dates for several extensions of production fields. Turning to natural gas, the DEA forecasts that Denmark will be self-sufficient until 2034 with the exception, however, of 2020 and 2021, which is mainly attributable to the restoration of the Tyra field that is scheduled to begin in September 2019 and continue until July 2022.

Besides the finishing of the eighth licensing round, major news in the Danish oil and gas industry so far in 2019 includes the environmental impact assessment-approval of the Baltic Pipe as well as the completion of Total and Noreco’s (separate) acquisitions of almost 50 per cent in total of the Danish Underground Consortium. On the political front, the formation of a new government in June 2019 with a distinct green agenda marks the highlight.

II LEGAL AND REGULATORY FRAMEWORK

The Danish field of upstream oil and gas activities is regulated through a number of different acts, statutory orders and guidelines.

i Danish oil and gas legislation

The main act regulating the Danish upstream oil and gas activities is the Danish Subsoil Act (DSA), which is a framework act. Alongside with the Danish Continental Shelf Act (CSA) and the Danish Pipeline Act (DPA), the DSA forms the body of regulation that creates the basis for the social management and management of most raw materials, including oil and gas, in Denmark. The main acts and their key provisions, as well as the most relevant statutory orders, are set out in overview in the following sections.

The Danish Subsoil Act

The DSA sets out the basic legal framework for the exploration and recovery activities concerning raw materials and hydrocarbons in the Danish subsoil and on the Danish
Denmark

The Danish Continental Shelf Act

The CSA is based on the UN Convention of the Continental Shelf. The purpose of the act is the creation of an elaborate Danish administrative basis of the sovereignty over mineral deposits, etc., pursuant to the Convention of the Continental Shelf.

13 Section 1(2) of the DSA.
14 Section 2 of the DSA.
15 Dan Jørgensen was appointed Minister for Climate, Energy and Utilities in June 2019.
16 See Section 2 in Statutory Order No. 419 of 2 June 2005 on the Payment of Fees connected with Certain Licences Issued pursuant to the Danish Subsoil.
17 See Statutory Order No. 661 of 1 June 2018 on Reimbursement of Expenses related to the Authorities’ Administration in connection with Hydrocarbon Activities.
18 See Sections 2 and 3 of Statutory Order No. 56 of 4 February 2002 on Submission of Samples and other Information about the Danish Subsoil.
19 Ratified by Denmark on 31 May 1963.
Under the CSA and in accordance with the requirements set out in the DSA, exploitation or exploration of natural resources on the Danish continental shelf can only take place with a licence or permit from the Danish state.\(^\text{20}\)

Additionally, the Act\(^\text{21}\) specifically requires a permit for the establishment of power lines and pipelines for transportation of hydrocarbons on the Danish continental shelf.

**The Danish Pipeline Act**

The purpose of the DPA is to improve the recovery of crude oil and condensate in the fields in the Danish part of the North Sea and to reduce the environmental impact of transportation and landing. Under the DPA, the owner, currently Danish Oil Pipe A/S\(^\text{22}\) (a subsidiary of Ørsted A/S), operates the pipeline on the Danish continental shelf from the Gorm field to Fredericia as well as separation facilities.\(^\text{23}\) Any party recovering liquid hydrocarbons in the Danish part of the North Sea is obliged to connect the field facility to the pipeline and use it to transport the crude oil and condensate intended for refining or marketing in Denmark.\(^\text{24}\) This obligation can be exempted by the Minister if the connection to the pipeline is considered uneconomical or inconvenient.\(^\text{25}\) In practice, the Minister’s powers under the act are carried out by the DEA. The DPA also governs the users’ payment of the costs of capital for establishing the facilities as well as operating costs deriving from the use hereof.\(^\text{26}\)

Turning to access to the upstream natural gas pipeline network, everyone may against payment be granted access to upstream pipelines and upstream systems (e.g., pipelines operated or constructed as a part of an oil or gas production along with the technical facilities related hereto) provided that they meet the third-party access requirements.\(^\text{27}\)

**Regulation on safety and protection of the environment**

Regulation of safety and the protection of the environment for upstream oil and gas activities is primarily set out in the Offshore Safety Act,\(^\text{28}\) the Act on Protection of the...
Marine Environment, 29 the Environmental Impact Assessment Act, 30 the Statutory Order on Offshore Impact Assessment (Statutory Order on OIA) 31 and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger. 32

The purpose of the Offshore Safety Act is to promote a high level of health and safety offshore in line with society's technical and social development. The act sets out a framework within which the market participants themselves may solve health and safety issues arising. 33 Under the Act, licensees must ensure that health and safety risks associated with offshore oil and gas activities are identified, assessed and reduced as much as reasonably possible. 34

The Act on Protection of the Marine Environment contributes to the protection of nature and the environment in order for society to develop on a sustainable basis respecting human conditions of life and protecting vegetation and animal life.

The Environmental Impact Assessment Act and the Statutory Order on OIA concerns environmental impact assessments, appropriate assessments regarding international nature conservation areas and protection of certain species in Danish territorial waters, in the Danish exclusive economic zone and on the Danish continental shelf. Certain projects related to the DSA, CSA and DPA (e.g., the production of oil) may only be initiated after an environmental impact assessment and certain other impact assessments have been carried out.

Under the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger, fixed installations, drilling rigs, drilling ships, etc., used for or in connection with exploration or extraction of raw materials on the Danish continental shelf must be surrounded by a safety zone. 35

**Regulation of taxation**

Taxation of the upstream oil and gas field is regulated in the Act on Taxation of Income Originating from Production of Hydrocarbons in Denmark (the Hydrocarbon Tax Act); 36 and in the Act on the Assessment and Collection of Taxes in connection with Production of Hydrocarbons (Act on Assessment and Collection). 37

See Section VI, for further information on the taxation schemes for upstream oil and gas activities.

**Regulatory agencies**

The DEA is an agency under the Ministry of Climate, Energy and Utilities and is, inter alia, responsible for matters relating to energy supply and consumption. 38 The DEA is responsible for the entire chain of tasks concerning energy production and supply, transportation and consumption, including energy efficiency and savings. Additionally, the DEA is responsible

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29 Consolidated Act No. 1033 of 4 September 2017 on the Protection of the Marine Environment with subsequent amendments.
31 Statutory Order No. 434 of 2 May 2017 on impact assessments, etc. offshore.
33 Section 1 of the Offshore Safety Act.
34 Section 5 of the Offshore Safety Act.
35 Section 1 of Statutory Order No. 657 of 30 December 1985.
36 See Consolidated Act No. 1153 of 18 September 2018.
37 See Consolidated Act No. 1152 of 10 September 2018 with subsequent amendments.
38 See Statutory Order No. 1512 of 15 December 2017 on the DEA's duties and powers.
for the Danish national CO₂ targets and initiatives to limit emissions of greenhouse gases. The power to award licences for exploration and exploitation of oil and gas is not among the DEA’s powers, it rests with the Minister.39

In addition to the DEA, the Danish Utility Regulator (DUR) has a supervisory and appeal function in the energy sector.40 The DUR’s tasks are set out in the acts regulating the supply of electricity, natural gas and district heating. The director of the DUR is formally appointed by the Minister for Climate, Energy and Utilities, but the Minister has no powers of instruction in relation to the DUR’s director or staff. Accordingly, the DUR is fully independent of the government and its personnel cannot seek or receive instructions from anyone in the performance of their duties and shall perform their duties with impartiality.41

Disputes regarding access to the upstream gas pipelines and fees and prices connected hereto are referred to the DUR with recourse to the Danish Energy Board of Appeal.42

Treaties
Besides the New York Convention,43 which has been ratified by Denmark,44 there are no other significant conventions or bilateral agreements specifically relevant to litigation in exploration or the production of oil and gas. Reference is made to the Act on Administration of Justice45 and the Danish Arbitration Act.46

Double taxation
Under the Hydrocarbon Tax Act, foreign persons and companies carrying out hydrocarbon activities in areas fully or partly subject to Danish sovereignty are subject to taxation in Denmark on the income from the activity from the point in time where the activity commences. If Denmark has entered into a double taxation treaty with the country where the foreign company is resident for tax purposes, the treaty may, however, modify the Danish tax liability.

III LICENSING
Any right to explore for or produce hydrocarbons requires a licence issued in pursuance of the DSA47 based on one of the licensing methods outlined in Section II.i. The DEA has finalised eight rounds48 of applications for licences to explore for hydrocarbons in the North Sea. The seventh licensing round covered the unlicensed area west of 6° 15’ eastern longitude, including Central Graben, where most of the Danish finds have been made. The eighth

39 See Statutory Order No. 1512 of 15 December 2017 on the DEA’s duties and powers, Section 8.
41 See Act No. 690 of 8 June 2018 on the Danish Utility Regulator, Section 2.
42 See Section 37 a of the DSA.
44 Statutory Order No. 117 of 7 March 1973 with subsequent amendments.
45 Consolidated Act No. 1284 of 14 November 2018 with subsequent amendments.
46 Act No. 553 of 24 June 2005 with subsequent amendments.
47 DSA Section 5.
48 The first round took place in 1984 and licences based on the seventh round were awarded in the spring of 2016.
round for the same area was open for applications until 1 February 2019 and resulted in five applications, which are currently being processed by the DEA. The DEA intends to initiate licensing rounds every second year with the next round planned for 2020.

In addition to the licensing rounds, Danish legislation has since 1997 foreseen an open-door procedure for unlicensed areas east of 6° 15’ eastern longitude. Applications may be submitted at any time between 2 January and 30 September of each year. In February 2018, the Danish government decided to stop future investigations and drillings for oil and gas onshore and in inland waters, thus limiting the open-door procedure to the North Sea east of 6° 15’ eastern longitude.

Nordsøfonden will participate with a 20 per cent stake in any licence awarded. The licencing rounds and licences issued based on the open-door procedure include model licence terms as well as a model joint operating agreement to be entered into if there are more participants in a licence. The model terms are set out by the DEA within the framework of the DSA and supporting regulation as set out in Section II.i.

The main terms of the model licence for the eighth round were as follows:

- **a** delineation of the area where the licensee obtains the exclusive right to explore for and produce oil or natural gas or both. Certain other rights may be allocated to third parties;
- **b** the frame for the work programme to be adhered to by the licensee;
- **c** the obligation to enter into a joint operating agreement within 90 days following granting of the licence;
- **d** extensive information requirements to the DEA and the DEA’s rights of participation as observer as well as confidentiality obligations;
- **e** liability issues (strict liability), insurance obligations, obligation to provide security;
- **f** regulation of revocation and termination of the licence, including decommissioning of facilities and the Danish state’s right of assignment of facilities, etc., intended for long-term use without payment of consideration;
- **g** the full immunity granted by the licensee regarding any claim that may be raised against the Danish state following the licensee’s activities, and
- **b** dispute resolution (the ordinary Danish courts unless agreement on arbitration) with venue in Copenhagen. Any licence issued is subject to Danish law in force.

As mentioned, if there are several parties to a licence (as will usually be the case due to the participation of Nordsøfonden) they are as part of the model licence terms obliged to enter into a joint operation agreement (JOA) regarding the exploration and production of hydrocarbons. The JOA is subject to the DEA’s approval. The terms of the most recent model

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49 The decision has subsequently been codified by Act No. 500 of 1 May 2019 on amendments to the Danish Subsoil Act.
50 See Section I.
51 The model licence terms Sections 2 and 3 with Annex 1.
52 ibid., Section 4 with Annex 2.
53 ibid., Section 18.
54 ibid., Sections 19–22.
55 ibid., Sections 30–32.
56 ibid., Sections 34–37.
57 ibid., Section 38.
58 ibid., Section 40.
JOA (2019) regulate, inter alia, the duration of the JOA; the obligations and responsibilities of the operator (e.g., information to the licensees, records to be kept, expenditures and change or removal of the operator); the set-up and working of the organising committee, including voting procedures; the work programmes to be performed with budgets, fees and accounting procedures; procedures in case one or more parties wants work undertaken that has not been approved by the organising committee (sole risk operations); offtake of hydrocarbons as well as regulation of assignments, encumbrances, withdrawals and defaults in payments.

The JOA is an agreement between the participants in a licence and the parties to a JOA may agree to changes in the wording of the JOA provided, however, that any such change is approved by the DEA.

IV  PRODUCTION RESTRICTIONS

A licence to establish and operate pipeline systems for use regarding activities covered by the DSA may be restricted by conditions issued by the Minister. Accordingly, a licence may be granted on terms restricting dimensions, transport capacity, ownership, etc.\(^5\) There are no further restrictions on production entitlements except for oil in crisis situations (oil reserve stocks).\(^6\)

Additionally, there are as such no restrictions on export of oil and gas produced in Denmark.

With respect to the above-mentioned DPA and the general requirements set out in the Statutory Order on Access to Upstream Pipelines,\(^6\) there are no specific requirements for sales of production into the local markets.

Laws applicable to price settings

In accordance with the Statutory Order on Access to Upstream Pipelines,\(^6\) prices, terms and conditions are negotiated between the parties.\(^6\) The overall conditions must not discriminate between applicants and the final agreement, including the prices, must be reported to the DUR. The DUR ensures that the owners of the pipelines do not abuse their (in reality) monopoly rights.\(^6\)

Further, the Danish Competition and Consumer Authority will apply the prohibitions against anticompetitive agreements and abuse of a dominant position in Sections 6 and 11 respectively of the Danish Competition Act. These provisions are equivalent to Articles 101 and 102 TFEU.

V  ASSIGNMENTS OF INTERESTS

It follows explicitly from the DSA that a licence may neither directly nor indirectly be transferred to a third party unless the DEA approves of the transfer including any terms and

\(^5\)  DSA, Section 17(2).

\(^6\)  DSA Section 17a and Act No. 354 of 24 April 2012 on Oil Minimum Stocks.

\(^6\)  Statutory Order No. 920 of 25 June 2018.

\(^6\)  ibid.

\(^6\)  See Section 5 of Statutory Order No. 920 of 25 June 2018 on Access to Upstream Pipelines.

\(^6\)  ibid.
conditions attached to the transfer. Accordingly, any transfers of shares that may result in a controlling interest in a licensee or the entering into agreements that may have a similar effect must be approved by the DEA. This also applies to transfers of shares or parts in a licence if there are several licensees to the same licence. The DEA may only approve of a transfer if after the transfer, the (new) licensee is also assessed to possess sufficient technical and financial means and may be expected to carry out their business in such way that society will obtain as much knowledge and benefit from it as possible. The DEA may in order to approve a transfer, whether in whole or in part impose conditions on the parties to the transfer. The Danish state has no preferential right of purchase to licences issued under the DSA.

Even though a transfer has been approved by the DEA, the transferor of a licence for exploration or production of hydrocarbons or a licence to establish or operate upstream pipelines retains a secondary financial liability for any decommissioning expenses regarding facilities existing at the time of the transfer. This secondary financial liability remains in force irrespective of the any subsequent transfers of (part of) the licence.

It is always a condition for approval of a transfer that the transferor issues a statement of acceptance of the secondary financial liability towards the licence’s licensees from time to time and the Danish state. Accordingly, no licensee can escape the financial liability for decommissioning costs.

It follows from the DSA that any expenses incurred by the DEA in the handling of a licence, including the approval of a transfer, shall be borne by the licensee.

Licences issued pursuant to the Subsoil Act enjoy immunity from legal prosecution.

VI TAX

The Danish hydrocarbon tax regime

The tax regime applicable to companies engaged in hydrocarbon exploration and production in Denmark consists of a combination of corporate income tax and hydrocarbon tax combined with a special hydrocarbon tax allowance.

In general, companies engaged in oil and gas activities are subject to the generally applicable Danish tax rules applicable to Danish companies and branches, with the adjustments provided in the Hydrocarbon Tax Act and the Hydrocarbon Tax Assessment and Collection Act.

Under the Hydrocarbon Tax Act, foreign persons and companies that carry out hydrocarbon activities in areas fully or partly subject to Danish sovereignty are subject to taxation in Denmark on the income from the activity from the time the activity commences. Hydrocarbon activity includes preliminary investigations, exploration and recovery of

65 See Section 29(1) of the DSA.
66 A provision to this effect is also included in the model licence for the eighth round, Section 33.
67 See Section 29(2) of the DSA.
68 See Section 5 of the DSA.
69 See Section 17 of the DSA.
70 See Section 29a of the DSA.
71 Statutory Order No. 661 of 1 June 2018 on the Reimbursement of Costs.
72 See Section 29(3) of the DSA.
73 Consolidated Act No. 1153 of 18 September 2018.
74 Consolidated Act No. 1152 of 10 September 2018 with subsequent amendments.
hydrocarbons and activities related therewith, including the installation of pipelines, supply services and transport by ship and pipeline of recovered hydrocarbons. If Denmark has entered into a double taxation treaty with the country where the foreign company is resident for tax purposes, the treaty may, however, modify the Danish tax liability.

All companies involved in oil and gas exploration are required to report hydrocarbon activities and tax liability to Skattestyrelsen – the Danish Tax Authorities. The relevant forms and further information can be found in English on the Danish Tax Authorities’ website.75

Taxpayers liable for hydrocarbon taxes are subject to special rules regarding the tax assessment pursuant to the Hydrocarbon Tax Assessment and Collection Act, which entails, inter alia, that separate tax returns must be filed for ordinary corporate income (income not covered by the hydrocarbon tax rules) and for each hydrocarbon income stream.76

ii Tax rates and income types

The two-string Danish hydrocarbon tax system combines corporate income tax at the rate of 25 per cent77 (Chapter 2 income) and a special hydrocarbon tax at a rate of 52 per cent (Chapter 3A income) for the income year 2019. The overall effective tax rate for Chapters 2 and 3A income is 64 per cent for the income year 2019.

Income covered by Chapters 2 and 3A includes first-time sales of hydrocarbons, gains and losses on licences, exploration rights and assets used for hydrocarbon activities and financial income related to the activities.

Income related to, inter alia, hydrocarbon feasibility studies, services to hydrocarbon companies, the construction of pipelines, services and transportation of hydrocarbons is not covered by Chapters 2 or 3A. This income is, as other ordinary corporate income, subject to the ordinary corporate income tax rate at 22 per cent for the income year 2019.

iii Ring-fencing

The ring-fence78 exhaustively list the streams of income that are subject to separate tax assessment under Section 20B of the Hydrocarbon Tax Act. In general, expenses and tax losses not related to Danish oil and gas activities may not be offset against the Chapters 2 and 3A oil and gas-related taxable income. However, Chapter 2 losses may be offset against ordinary corporate income.

iv Incentives

Chapters 2 and 3A tax losses realised after 2002 may in general be carried forward indefinitely.

A special hydrocarbon tax allowance has been introduced to ensure that the 52 per cent Chapter 3A hydrocarbon tax is levied exclusively when production from a field is particularly profitable. The Chapter 3A hydrocarbon tax allowance is an uplift of 30 per cent on the depreciation allowance of qualifying expenditures, including capitalised exploration costs and investments made in production plant and equipment. The allowance only applies to

75 See www.skat.dk.
76 I.e., for separate income under Part 2 and for hydrocarbon income pursuant to Part 3A of the Hydrocarbon Tax Act.
77 The ordinary corporate income tax of 22 per cent added 3 per cent for hydrocarbon activities for 2018.
78 See Section 4 of the Hydrocarbon Tax Act.
the tax basis for hydrocarbon tax. The uplift is allowed as a 5 per cent deduction per year over a six-year period and is granted in addition to the ordinary tax depreciation of plant and machinery and amortisation of capitalised exploration costs over a five-year period.

Additionally, political agreement has been reached to reduce taxation for oil and gas exploitation in an ‘investment window’ from 2017–25. The purpose of the political agreement is to incentivise hydrocarbon operators to rebuild the Tyra-field through which almost all natural gas from the Danish North Sea fields is transferred. The incentives are contained in Chapter 3B of the Hydrocarbon Tax Act.

The agreement provides for, inter alia, a raise in the hydrocarbon deduction from 5 to 6.5 per cent (capital up-lift) and an accelerated timing of capital allowances meaning that investments made within the investment window may be subject to capital allowances from the time of investment rather than from the time of delivery of an asset ready to generate revenue.

Uptake of the incentives that taxpayers covered by the Hydrocarbon Tax Act are entitled to is voluntary; however, the investment window also contains an additional surplus tax, which becomes payable if the global oil prices reach certain thresholds. This surplus tax is imposed at either 5 per cent or 10 per cent and may be offset in the hydrocarbon tax.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Summary of environmental laws and regulations applicable to oil and gas operations

The most relevant environmental laws and regulations applicable to oil and gas activities are the Act on Protection of the Marine Environment, the DSA, the Environmental Impact Assessment Act, the Statutory Order on OIA, the Statutory Order on Alerts Regarding Pollution of the Sea from Oil and Gas Facilities, Pipelines etc.,79 and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.

Licences for offshore projects involving a risk of affecting the environment may only be granted and utilised pursuant to an environmental impact assessment (EIA)80 and an impact assessment regarding international nature conservation81 as well as after consultation with the members of the affected general public, authorities and organisations.82

Exploration activities like pre-investigations (for example, seismic surveys) and drilling may not always require the preparation of an EIA or other impact assessments.83 As a rule, any planned work, including well drilling, shaft sinking, driving adits and drifts, may only be initiated after obtaining prior approval from the DEA.

79 Statutory Order No. 909 of 10 July 2015.
80 Under the Environmental Impact Assessment Act.
81 See Sections 28(a), 28(b) and 28(c) of the DSA and the Statutory Order on OIA.
82 See Section 35 of the Environmental Impact Assessment Act and Section 6 of the Statutory Order on OIA.
83 See generally the Environmental Impact Assessment Act and the Statutory Order on OIA for more detailed descriptions (i.e., offshore projects that necessitate the preparation of an EIA, requirements concerning the contents, other information to be submitted and procedures to follow).
Details of regulatory agencies with responsibility for environmental regulation

Besides the above-mentioned authorities the DEA and the DUR, the Danish Environmental Protection Agency (EPA) is the main regulatory authority for environmental regulation in Denmark.

The EPA is an agency under the Danish Ministry of Environment and Food. The Ministry is responsible for legislation and is the authority in charge of major national responsibilities as well as particularly complex tasks. The EPA prepares legislation and guidelines and grants authorisations in several areas.

Description of any key environmental approval necessary for oil and gas activities

When working with upstream oil and gas activities offshore, it is necessary to obtain permission for each and every significant step undertaken. Environmental authorisations, as well as EIAs, may also be required depending on the specific project and its location.

Summary of legal requirements with respect to decommissioning

The DSA regulates the decommissioning of oil and gas facilities such as, for example, the decommissioning of physical structures on and offshore. The DSA includes provisions set out in the Convention on the Continental Shelf of 1958 and the Sea Law Convention of 1982. The DSA also regulates the effect of licence expiry, cessation, relinquishment or revocation.

A licence under the DSA may be conditioned upon the Danish state being entitled to take over all or part of any facilities, equipment and installations intended for long-term use, as well as any required accessories and materials. The licensee is required to have the capacity to remove all or part of any facilities, installations, etc.

VIII FOREIGN INVESTMENT CONSIDERATIONS

There are as such no legal requirements regarding the type of entity (partnership, limited liability company, etc.) applying for a licence. As Denmark is part of the European Union, the freedom rights set out in the Treaty on the Functioning of the European Union (e.g., the free right of establishment and free movement of capital) apply in Denmark.

Licences are granted after close assessment of the applications based on the criteria listed in the DSA and the terms and conditions stated in the licensing documents. Among these criteria is, inter alia, a requirement to demonstrate the necessary expertise and financial resources. There are no special requirements or limitations on using foreign companies or hiring foreign workers in connection with upstream oil and gas activities in Denmark. However, in connection with obtaining a licence for exploration for and production of hydrocarbons, companies participating in the licence must be registered with the tax authorities in Denmark and provide the necessary information for that purpose. As an alternative, companies can, for example, establish a Danish subsidiary or register a business address in Denmark.

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84 See Section 8 of the DSA.
85 See Section 24(a) of the DSA.
86 See Section 12(a) of the DSA.
87 ibid.
IX CURRENT DEVELOPMENTS

Following the election on 5 June 2019, the Danish Social Democratic Party formed a new minority government on 27 June 2019 supported by the other left-wing parties of the newly constituted Danish parliament. In line with the tendencies of the 2019 European Parliament election held just before the Danish election, the new government has a strong focus on the climate agenda. Accordingly, the political agreement88 between the government and its supporting parties proclaims that Denmark will lead the way in combating the climate crisis, assume the international leadership for the green transition and do what it takes to honour the Paris agreement.

More specifically, the political agreement foresees, inter alia, (1) the introduction of a new climate act for a 70 per cent reduction89 of greenhouse gasses by 2030 and (2) a complete stop to the sale of diesel- and gasoline-fuelled cars by 2030. It remains to be seen whether the new government will amend the latest energy strategy, which gives priority to the North Sea production of oil and gas until 205090 as part of a green transition to ensure that at least 50 per cent of Danish energy will be renewable by 2030 and that Denmark will be independent of fossil fuels by 2050.

Besides the finishing of the eighth licensing round,91 the market for exploration and production from the Danish part of the North Sea saw the completion of two major transactions in 2019: (1) Total’s acquisition on 1 April 2019 of Chevron Denmark Inc including Chevron’s 12 per cent share of the Danish Underground Consortium (DUC);92 and (2) Noreco’s acquisition on 31 July 2019 of Shell Olie- og Gasudvinding Danmark BV including Shell’s 36.8 per cent share of the DUC.

Additionally, in July 2019 the Baltic Pipe reached a milestone as it was EIA-approved by the EPA following the issuance of a national plan for the project by the Minister for Industry, Business and Financial Affairs.93 The Baltic Pipe94 is a combined on- and offshore pipeline for gas that will connect Denmark and Poland to the Norwegian gas fields in order to ensure security of supply, increased competition and reduce prices and CO₂ emissions. West of Denmark, the pipe will connect to the Norwegian Europipe II in the North Sea, run through Denmark and connect to the Polish grid east of Denmark across the Baltic Sea. The Danish part of the project involves a new 105–110km offshore pipe, 210km of additional piping onshore, a new compressor station in Sealand and an extension of the receipt terminal in Jutland. Commissioning of the Baltic Pipe is expected in the autumn of 2022.

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88 Issued by the participating parties on 25 June 2019, available in Danish on the internet through various media.
89 With 1990 as benchmark.
90 In July 2017, the Committee for the Preparation of an Oil and Gas Strategy concluded that Denmark has a substantial potential of roughly 3 billion barrels oil equivalents (BOE) compared to the 3.8 billion BOE already produced (2015 figures).
91 See Section I.
92 The DUC is a joint venture between Total (43.2 per cent), Noreco (36.8 per cent) and Nordsøfonden (20 per cent) for the production of oil and gas from the area covered by the Sole Concession. The DUC is responsible for almost 90 per cent of the Danish production and owns a significant part of the critical infrastructure in the Danish part of the North Sea.
93 See the news statement from the Danish Environmental Protection Agency, released on 12 July 2019, available at www.mst.dk.
94 For more information about the Baltic Pipe, please visit www.baltic-pipe.eu or the homepage of the Danish TSO, www.energinet.dk.
I INTRODUCTION

With a daily production of approximately 550,000 barrels per day, crude oil continues to be the most important export in the country, as it has been over the past four decades. Ecuador is an OPEC member.

In 2019, the Ecuadorian government has continued its efforts to recover and strengthen its hydrocarbon industry. The government expects to maintain a steady production of approximately 550,000 barrels per day and increase it up to 700,000 barrels per day by 2021. This effort will mandatorily include offering oilfields to private companies through public tender rounds, as well as continuing the improvement of operations of the state-owned company in charge of the exploration and exploitation of hydrocarbons in Ecuador, Petroamazonas EP (PAM).

Petroecuador EP is the state-owned company that is in charge of midstream and downstream activities. Petroecuador has a refining capacity of 175,000 barrels per day through three refineries, Esmeraldas (110,000 barrels); Shushufindi (45,000 barrels) and Libertad (20,000 barrels), that produce mainly gasoline, diesel and jet fuel among others.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

Ecuador has a civil law system, with its most recent Constitution approved on 20 October 2008 and amended in 2015. Pursuant to Articles 1 and 408 of the Ecuadorian Constitution, natural resources are the unalienable property of the Ecuadorian state and the government of Ecuador. Articles 313 to 315 of the Constitution establish that the state is responsible for the management of ‘strategic sectors’ through state-owned or state-controlled companies, and the regulation of these sectors through the corresponding public entities. Strategic sectors include, among others, energy in all its forms, non-renewable natural resources (including oil and gas, and mining) and hydrocarbons refining.

The Hydrocarbons Law regulates the Ecuadorian oil and gas industry. It contains the basic regulations for all the different types of contracts to be entered into with the state, including contract termination, state income and fiscal terms, transportation, commercialisation, exports, distribution, pricing and other provisions.

1 Sebastián Cortez Merlo is a partner, Francisco Larrea Naranjo is a director and María Elena Sanmartín is an associate at Noboa Peña & Torres Abogados.
Furthermore, there are several specific regulations that regulate specific matters of the industry, for example, Regulations to the Hydrocarbons Law, Hydrocarbons Operations Regulations, Hydrocarbons Operations Environmental Regulations and other laws and regulations regarding environmental issues, taxation and accounting.

ii Regulation

The Ecuadorian state currently acts through: (1) the Ministry of Energy and Non-Renewable Natural Resources\(^2\) (the Ministry), which is in charge of carrying out hydrocarbons policies, and is responsible for executing, amending and administering areas and oil contracts, as well as the country’s hydrocarbons resources; (2) the Hydrocarbons Regulation and Control Agency, which is in charge of regulating, controlling and supervising the technical, administrative and operative activities in the different stages of the hydrocarbons industry, including upstream, midstream and downstream activities; (3) the Ministry of the Environment, which is the national environmental authority in charge of applying environmental policies, and regulating, controlling and supervising all the environmental issues in all industries, including oil and gas; and, the Internal Revenue Service, which is in charge of taxation matters for all industries, including oil and gas.

iii Treaties

Ecuador is a party to the New York Convention, which has been in force since 1962.\(^3\) Additionally, Ecuador is a party to the Inter-American Convention on International Commercial Arbitration of Panama of 1975, in force since 1991. In 2017, Ecuador terminated all of the bilateral investment treaties to which it was a party. Finally, Ecuador has 18 double taxation treaties.

III LICENSING

The exploration and production of oil and gas resources shall be conducted directly and exclusively by the state through its state-owned companies. By exception only, the state may delegate these activities to local or foreign private, public or mixed-economy companies. Private companies with the required experience, and technical and economic capacity may enter into contracts with the state, awarded through a public tender process for certain oil and gas fields.

The Ecuadorian Constitution provides that the Ecuadorian state take in exploration and production contracts must be higher than the private contractors’ take.

Pursuant to the Hydrocarbons Law, the state may award the following contracts to private, public or mixed-economy companies: (1) association contracts; (2) participation contracts; (3) risk service contracts for the exploration and production of hydrocarbons; or (4) other forms of delegation pursuant to Ecuadorian law.

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\(^2\) Executive Decree 399, dated 18 May 2018, ordered the merger of the Ministry of Hydrocarbons, Hydrocarbons Secretariat, Ministry of Electricity and Ministry of Mines, creating the Ministry of Energy and Non-Renewable Natural Resources, which succeeded all their rights and obligations.

\(^3\) Ecuador subscribed the NYC with the following reservations: (1) application only to recognition and execution of award rendered in states parties; and, (2) application only to awards derived from legal relations, contractual or not, considered as commercial, according to the internal legislation.
Regarding the aforementioned types of contracts, Ecuador has traditionally implemented two types of contracts, namely participation contracts and service contracts, for the exploration and production of hydrocarbons with the Ministry.

More recently, Ecuador has also implemented another type of contract known as a specific integrated services contract with PAM.

The participation contract is a production sharing agreement entered into by the state, pursuant to which it delegates to the contractor the right to explore and exploit hydrocarbons in the area designated in the contract. The contractor bears the risk for all investments and assumes all costs and expenses required for exploration, production and development. The contractor has the right to participate in the production, which is calculated taking into consideration the production volume and the sales price of crude oil. The sales of contractor's participation in production constitutes contractor's gross income, from which the contractor must pay all investments, costs and expenses, applicable taxes and profit sharing contributions. The participation in production may be received in kind or in cash, subject to prior agreement between the parties.

In line with Ecuador’s constitution, the participation contracts includes a formula to adjust the contractor's take in the contract, in order to ensure that Ecuador's take of the contract (oil sales and taxes) is higher than contractor's take.

Under a service contract, the contractor is required to provide exploration and exploitation services, invest in equipment, materials and technology with its own economic resources and at its sole risk, in exchange for a fee per net crude oil barrel produced and delivered to the state at the measurement point. The contractor's fee considers an estimate of the amortisation of the investments, costs and expenses and a reasonable profit taking into consideration the risks borne by the contractor. The contractor is the sole and exclusive operator and will be entitled to the payment of a tariff per barrel of net oil produced in the contract area. The state takes 25 per cent of the gross income from the sales of the crude produced in the contract (the ‘sovereign margin’). Variations in the international price of oil affect the payment of the contractor's per barrel fee. Payment to the contractor is made in accordance with the monthly ‘available income’ derived from the production of contract area. The available income is the value of the gross income of the crude produced in a certain month (barrels produced times the market price of oil) minus the sovereign margin (25 per cent of gross income) mentioned above, transportation and commercialisation costs of Ecuador and certain applicable taxes and contributions. If the available income in a given month is less than the per barrel fee payment, the contractor only receives the amount of the available income and the difference is accumulated in an accumulation account (the ‘carry forward’ account).

In 2012, Petroamazonas EP assumed the operations of all the fields and areas that were operated by Petroecuador at the time. Pursuant to a specific integrated services contract that Petroamazonas has implemented, the contractor agrees to carry out specific works, activities or services for PAM, which continues to be the designated operator of the field, providing the technology, capital and equipment or machinery necessary to perform its obligations, in exchange for a fee or remuneration in cash.

The specific integrated services contract is entered into to perform concrete, specific and particular activities. This type of contract is not a direct exploration and production contract or concession by the state, but rather it is a contract for the provision of services by the contractor, where PAM remains as the operator of the field and the contractor renders services to PAM. In this type of contract, the state generally retains the operational risks, and the contractor only assumes the risk of its own investments made to provide the services in exchange for a fee.
i  Tender process for awarding participation and service contracts
When Ecuador decides to carry out exploration and exploitation activities, it may choose – following specific bidding regulations – private companies, associations or consortia with the required financial solvency and technical capabilities in the hydrocarbons industry.

The Hydrocarbons Bidding Committee (COLH) is in charge of conducting the bidding procedure and enacting the bidding terms. Once the winning bidder is awarded, the corresponding contract is entered into between the Ministry and the awarded company.

ii  Special procedures for awarding specific integrated services contract with PAM
The state has conducted procedures to award specific integrated services contracts to international companies for the purpose of increasing the production of existing fields under the operation of PAM. Once the potential partners have been determined, the board of directors of PAM resolves to begin a process for the direct negotiations of the contract with the selected bidder.

iii  Revocation and expiry of licences
With respect to the contracts entered into with the Ministry, the Hydrocarbons Law establishes several causes for which the Ministry may declare the unilateral termination of a contract, which is called ‘caducity.’ The effects of caducity are the immediate return of all assets and production to the state and calling up contractual bonds. Caducity may be declared for breach of contract, unfulfilled committed activities, suspension of activities, failure to deliver the state’s share, and transfer of contractual rights without prior approval of the Ministry, among others. In order to declare caducity, the Ministry must comply with the procedure established in the law. In contrast, regarding contracts subscribed with PAM, termination causes will be indicated in the contract, including termination by mutual agreement.

IV  PRODUCTION RESTRICTIONS
There are no restrictions on production or export of entitlements. Under participation contracts, the contractor is entitled to receive the agreed participation, and is responsible for the transportation and export of its share of production. Under service contracts with the Ministry and specific integrated services contracts with PAM, all production is delivered to the state at the delivery centre, and the state is responsible for the transportation and export of the production. There are no requirements for sales of production into the local market. Commercialisation of crude oil products is an activity heavily regulated by the state that includes subsidies for many products (gasoline and LGP, among others) and regulated prices. Price setting corresponds to the state-owned company Petroecuador.

V  ASSIGNMENTS OF INTERESTS
Transference of interests in service contracts and participation contracts requires prior approval from the Ministry. Failure to obtain approval is cause for termination under caducity. The transference of interests approval procedure is regulated, and requires the Ministry to determine that the assignor is technically and financially capable to conduct the operations under the contract. The transference requires the assignee to pay a fee equal to: (1) US$5,000 per participation interest assigned or (2) 0.001 times the net profits obtained
in the year preceding the transfer or assignment. The assignor has to pay a fee equal to US$5,000 per participation interest assigned. Ministry authorisation is mandatory, whether or not the transference involves a change in control. The Ministry usually takes from eight to 12 months to issue the authorisation.

VI TAX

Ecuador’s take (in addition to crude sales income) also comes from the following taxes and contributions: (1) 25 per cent income tax rate; (2) 15 per cent profit-sharing (15 per cent of net profits before income tax); (3) 12 per cent value-added tax; (4) 5 per cent currency remittance tax; (5) municipal taxes; and (6) other fees and contributions levied by hydrocarbons and other authorities.

In the Ecuadorian tax system, foreign and domestic sourced income is subject to income tax, which applies to all industries, including oil and gas. Companies operating through locally incorporated companies or a subsidiary are subject to pay annual income tax on the net profit of each year at a rate of 25 per cent. Companies are required to make a prepayment of income tax, following the rules set forth in the law.

Dividends paid after the payment of annual income tax are exempt, provided that: (1) the final beneficiary is not an individual with permanent tax residency in Ecuador; and (2) the Ecuadorian company complies with the shareholder’s annual annex report to reveal the final effective beneficiary of the company. Dividends paid to individuals who are tax residents are subject to income tax withholding at a rate that ranges from zero to 35 per cent, depending on the amount distributed.

i Withholding taxes

According to Ecuadorian legislation, all payments or crediting on account, whether directly or indirectly, considered as taxable income for the recipient, are subject to withholding taxes. Therefore, remittances of income from an Ecuadorian source to non-residents are subject to withholding taxes. The tax is withheld on the gross amounts remitted, with no deductions allowed. The taxpayer of these withholding taxes is the non-resident beneficiary. However, the local taxpayer is considered as a withholding agent, and as such, is jointly and severally liable.

Almost all types of payments made abroad are subject to income tax withholdings, at a 25 per cent rate; however, this percentage can be reduced through the application of double taxation treaty benefits. A 2 per cent withholding tax applies to payments made to local beneficiaries for the provision of services, and a 1 per cent withholding tax is applied to the acquisition of goods. Income tax withholding at a rate of 35 per cent, applies to payments made abroad to recipients in tax havens, low taxation jurisdictions or preferential tax regimes.

Interest payments and financial fees are generally subject to 25 per cent income tax withholding; however, if the loan has been granted by a foreign financial institution, specialist non-financial institution or an international organisation, no income tax withholding shall apply on the interest payments, provided that additional requirements are met. It is noteworthy to mention that thin capitalisation rules are in force in Ecuador, establishing a ratio of 3:1 foreign debt to equity.
ii Remittance tax
All Ecuadorian taxpayers that remit currency abroad are subject to a 5 per cent tax on the amount transferred, regardless of whether the transaction is made through a financial institution or if the financial resources are not located in Ecuador. Dividends distributed to foreign residents shall be exempt from remittance tax to the extent that the recipients of the dividends are not domiciled in a tax haven or a lower tax jurisdiction. Remittance tax payments may be considered income tax credit for five fiscal years in some cases.

iii Transfer prices
Ecuador follows OECD rules, complying with the arm’s-length standard.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING
The Ecuadorian Constitution provides a responsabilidad objetiva regime of strict liability for environmental damage. Article 396 of the Constitution sets forth that ‘liability for environmental damage is strict’. Strict liability, within the context of the Constitution, means that for the oil operator to be liable, the state shall only establish that environmental harm exists, and that the harm was found in the areas where the oil operator undertook petroleum activities referred to in the Constitution. It is worth emphasising that, under the Constitution, strict liability is a liability ‘without fault’. Thus, the state does not need to prove the existence of a causal link between the action or omission and the environmental damage found in the areas where the oil operator conducted operations. In order to be exempt from liability, however, oil operators must establish that the damage arises from (1) force majeure; (2) actions or omissions of the party affected by the damage; or (3) actions or omissions of a third party. This strict liability requires full restoration of the ecosystem to its original state, in addition to the obligation to compensate affected third parties, as well as the respective fines that may be applicable.

The Organic Environmental Code establishes the general environmental guidelines and environmental policy of the state. This law sets out each of the environmental authorities and their duties, and establishes the environmental management system. Private investments in projects that might impact the environment are required to obtain an environmental licence through this system, for which an environmental impact assessment must be carried out. Without the environmental licence, no activities can be performed. For oil and gas activities, the environmental licence must be obtained by the operator. Additionally, throughout the life of the contract, the operator must carry out environmental audits according to the corresponding environmental impact assessment.

The Environmental Regulation to Hydrocarbon Operations contains specific provisions pertaining to the exploration, production, storage, transportation and industrialisation of hydrocarbons. All activities that could have an impact on the environment are contemplated in this regulation. Under this regulation, operators must deliver an annual programme of environmental activities to the Ministry of Hydrocarbons by the first of December of every year. Operators must also deliver an environmental budget for the following year for evaluation and approval on the basis of the pronouncement of the Undersecretary for Environmental Protection. Additionally, the operator must provide an annual environmental report due by the first of January of each year.

Regarding decommissioning, the contractor must perform the final environmental impact assessment audit. Additionally, all tax and labour matters arising during the term of the contract, as well as all pending obligations with subcontractors, must be liquidated.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

A branch of the foreign company or a local subsidiary must be created to enter into a contract. It is not necessary that the branch or the subsidiary be set up in Ecuador during the tender process, but it is mandatory once the contract has been awarded.

The following is required to establish a foreign branch in Ecuador: (1) the company’s by-laws should allow for establishment of branches in foreign countries; (2) a legal existence certificate granted by the corresponding government authority; (3) resolution from the shareholders, board of directors or any other duly authorised body or official, authorising the establishment of a branch, assigning a minimum initial capital of at least US$2,000 and appointing a legal representative in Ecuador; (4) issuance of power of attorney granted to whoever is appointed as the company’s legal representative of the branch in Ecuador; (5) Ecuadorian consulate certification that the company exists; and (6) a corporate bank account in Ecuador with at least US$2,000.

The procedure to establish a branch is the following: (1) submit a petition to the Superintendence of Companies that includes the documents listed above; (2) the Superintendence of Companies will issue a domiciliación resolution approving the registration and the power of attorney; (3) the resolution must be registered in the Mercantile Registry; and (4) after the resolution is duly registered, a local tax ID number and the patente – for commercial operation tax – in the corresponding municipality must be obtained. Upon completion of this procedure, the branch is ready to operate.

The procedure to incorporate a company is the following: (1) the issuance of a public deed of incorporation from a public notary; (2) registration of the public deed of incorporation in the Mercantile Registry; (3) once the incorporation is duly registered, it must be notified to the Superintendence of Companies in order to take note of the incorporation; (4) after the registration in the Mercantile Registry and the Superintendence of Companies, the local tax ID number and the patente for commercial operation tax must be obtained in the corresponding municipality. Upon completion of this procedure, the company is ready to operate.

Additionally, in order to subscribe a hydrocarbons exploration and exploitation contract, the company must get registered in the Hydrocarbons Registry of the Ministry.

It may take up to six weeks to complete the entire procedure. The costs for setting up a branch or incorporating a company will not exceed US$5,000, plus legal fees.

ii Capital, labour and content restrictions

Capital

Ever since the establishment of the US dollar as the legal currency in Ecuador, there are no restrictions on capital movements abroad, other than the remittance tax, or access to foreign exchange of currencies.

Labour

Below are some general considerations regarding the Ecuadorian labour regime:

a minimum wage for 2019 is US$394.00 dollars per month;

b two additional mandatory pay cheques, commonly referred to as the thirteenth and fourteenth salaries are required. The thirteenth salary must be made in December, while the fourteenth must be made by March (Coast Region) or August (Highlands or Amazon Region);
from the thirteenth month onwards, a payment, corresponding to 8.33 per cent of the employee's salary, must be made to the reserve fund;

the employer must pay 12.15 per cent of the employee's salary to social security, on a monthly basis;

normally, contracts are signed with an employee for an undefined duration. If the employer wants to terminate the contract, the employee must be indemnified;

employees have the right to 15 days of vacation each year, plus one additional day per year worked over five years for the same employer;

employees are required to work eight hours per day, and 40 hours per week. By mutual agreement, the employee may work extra hours for overtime pay. However, in the oil and gas industry, special working schedules can be used with prior approval of the labour authority; and

the company must have internal regulations regarding safety and healthcare for the employees.

Outsourcing employees is prohibited. However, oil and gas companies are allowed to contract complementary services or technical and specialist services under civil regulations instead of labour regulations, if these activities are not directly related to the company's primary business activities.

As of May 2018, the Organic Law for the Integral Planning of the Amazon Region has been in force, establishing the preferential employment right, which means that companies carrying out their activities in the special jurisdiction of the Amazon Region shall hire no less than 70 per cent of local residents, to perform non-skilled activities, save the cases where qualified skilled labour does not exist.

Additionally, the Hydrocarbons Law establishes certain limitations for hiring local and foreign workers, which must be observed. Finally, in accordance with immigration legislation, all foreign workers must obtain a visa.

iii Anti-corruption

The Constitution and the Organic Criminal Code are the primary laws that criminalise corruption-related crimes. Thus, the Constitution sets out prohibitions and liability warnings for public officials when performing their duties, as well as when handling public goods and resources. The aim is to prevent them from being involved in bribery, extortion, influence peddling, embezzlement and unlawful enrichment. Other laws, such as the Organic Law on Public Service, the Public Procurement Law, the Organic Law on the Transparency and Social Control Branch and the Organic Law on the Council for Citizen Participation and Social Control also set forth anti-bribery rules. Additionally, Ecuador is a signatory to the Inter-American Convention against Corruption of 29 March 1996. Finally, in 2005, Ecuador ratified the UN Convention against Corruption.

Despite the general legislation described above, Ecuador does not have specific anti-corruption rules for the oil and gas industry. Nevertheless, the Ministry is working on new anti-corruption rules that will be applicable to state-owned oil companies.

IX CURRENT DEVELOPMENTS

The participation contract model was used by Ecuador from the early 1990s to 2010 when Ecuador, pursuant to new reforms in the national oil industry, switched to the service
contract model. Ever since 2010, it has been the policy of the government of Ecuador to award services contracts for the exploration and production of hydrocarbons, and not to award participation contracts. However, in 2018, the participation contract was reinstated by the government of Ecuador in the latest oil and gas round (Intracampos 1), through which seven oilfields were awarded to private investors.

It is expected that a new Round, ‘Intracampos 2,’ will be launched late in 2019 under very similar conditions, using the same model of the participation contract used in the previous round.

PAM also carried out an oil and gas round in 2018 in order to select private investors for the provision of integrated services with contractor financing for the development of several oilfields operated by PAM. Three oilfields were awarded in this round.

In an interesting judicial development, in 2019, the Waoranis, an indigenous ancestral native community in the Ecuadorian Amazon Region, achieved a victory in the courts, with a ruling that declared the violation of their collective right to self-determination and prior, free and informed consultation regarding non-renewable resource exploitation projects on their lands. The ruling prevents oil exploitation in part of their ancestral territory and orders the prohibition of any type of exploitation on 180,000 hectares within Block 22, which has not been granted to any company yet. As an integral reparation measure, the court ordered the Ecuadorian state to conduct a prior, free and informed consultation in the Waorani community, applying the Ecuadorian Constitution and the standards established by the Inter-American Court of Human Rights and the Constitutional Court of Ecuador.

Finally, the government has decided to merge Petroecuador EP and Petroamazonas EP, in order to have – again – a single state-owned company in charge of all phases of the hydrocarbons activity in Ecuador.
Chapter 11

GABON

Jean-Pierre Bozec

I INTRODUCTION

Gabon has been an oil producer for more than 50 years, and while it is located in the famous oil-rich Gulf of Guinea, its production has been reduced by half since its peak oil production in 1997 with no major oil discoveries for several decades. Production is now less than 195,000 barrels a day, with a total production for 2018 at around 9.7 million tonnes, with 2 billion barrels of proven offshore and onshore reserves according to OPEC’s world proven crude oil reserves by country for 2018.

Thanks to the geology of the area and new exploration techniques, experts consider that undiscovered major hydrocarbons should be located in the Gabon basin. In order to reduce the decline of mature fields and boost exploration, the Gabonese government enacted a new hydrocarbons law on 16 July 2019.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

After the 2014 reform of the Gabonese oil and gas sectors and because of the market situation, Gabon decided to adjust again its legislation by adopting the new hydrocarbons Law No. 02/2019 on 16 July 2019 in order notably to restore attractiveness of the Gabonese basin and at the same time promote its 2018–19 bidding round for its 35 offshore blocks. The production sharing contracts’ (PSCs) key terms are summarised in Section III.

ii Regulation

The new hydrocarbons Law No. 02/2019 provides that an independent regulatory agency be created in order to regulate and control upstream and downstream activities, but the Gabonese Minister in charge of hydrocarbons remains the entry point in order to enter into Gabon oil and gas activities.

The national Gabon Oil Company (GOC) acts as a partner with oil operators and does not currently generally manage the state’s participations, which mainly remain under the control of the Minister in charge of hydrocarbons, but GOC has become more and more involved in oil transactions.

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iii  Treaties

Gabon is a member state of the Economic and Monetary Union of Central Africa, states sharing notably some common customs, financial and tax rules as well as the OHADA organisation which enacted common business law legislation for 17 African countries.

Gabon is also a member state of several international treaties regarding notably maritime organisation, pollution, climate, investment protection and arbitration. Gabon notably ratified the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, as well as the ICSID treaty.

Under usual PSC terms, any dispute between parties shall usually be settled through ICC (International Chamber of Commerce) arbitration.

While the state usually refuses to waive its rights for immunity of execution on its assets in PSCs, past experience demonstrates that Gabon complies with international arbitration awards, subject to compliance with the domestic enforcement procedure of foreign decisions and awards.

III  LICENSING

i  Licencing regime

A new hydrocarbons law was promulgated on 16 July 2016 by Law No. 02/2019, notably replacing former hydrocarbons Law No. 11/2014.

This Law No. 02/2019 provides for the state’s approach in its relations with operators and for improvement of the attractiveness of the Gabonese basin by offering better technical, economic and fiscal terms.

As far as upstream activities are only concerned, the Law proposes to operators several types of upstream contracts according to models to be approved by a Ministerial Order, which cannot, however, derogate from the hydrocarbons Law. These are:

a  services contracts (for geological and geophysical and other studies for state promotion of the oil and gas domain);

b  technical evaluation agreements (superficial appraisal and limited to 18 months);

c  production sharing contracts (development and production);

d  exploration and production sharing contracts (exploration, development and production); and

e  exploitation contracts (for marginal and mature fields),

Most of all types of oil contracts listed above are approved by Presidential Decree, save for the technical evaluation agreement, which is signed by the Gabonese Minister in charge of oil.

While certain services contract was signed in the past, in particular for multi-client programmes, PSCs remain the main model used in the upstream industry, and all blocks offered in the current bidding round involved PSCs.

ii  Licencing awarded process

Pursuant to the 2019 hydrocarbons Law, access to the upstream oil sector is either by way of tender process or through direct consultation, both processes leading to the signature of hydrocarbons contracts.

Currently and in addition to the 12th bidding round launched in October 2018 (due to elapse in January 2020) for 12 shallow water and 23 deep-water blocks, certain direct negotiations are in progress on other blocks available.
### Summary of key terms for licences

<table>
<thead>
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<th>Issues</th>
<th>PSC terms under 2019 hydrocarbons law</th>
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</thead>
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<tr>
<td><strong>Exploration period</strong></td>
<td>10 years maximum (including extensions) according to different phases to be negotiated in the PSC</td>
</tr>
<tr>
<td><strong>Work commitments during exploration phase</strong></td>
<td>Volume, budgets and phases negotiable provided they do not exceed eight years, subject to possible limited extensions (in the maximum limit of 10 years)</td>
</tr>
<tr>
<td><strong>Exploitation period</strong></td>
<td></td>
</tr>
</tbody>
</table>
| Oil                                         | • 10 + 5 + 5 + 5 in conventional areas; and  
|                                             | • 15 + 8 + 7 years in deep and ultra deep offshore |
| Gas                                         | • 15 + 5 + 5 in conventional areas; and  
|                                             | • 20 + 7 + 8 in deep and ultra deep offshore |
| **State participation**                    | 10 per cent maximum during development and exploitation, in addition to possible 10 per cent acquisition at market price of shares in any O&G producer's share capital |
| **State-owned oil company (GOC)**          | Maximum of 15 per cent from exploration period at market value |
| **Superficiary royalty**                   | Exploration: minimum of 100 CFA francs per hectare  
|                                             | Exploitation: minimum of 6,000 CFA francs per hectare |
| **Cost stop**                              | For oil:  
|                                             | • 70 per cent for conventional domains for oil; and  
|                                             | • 75 per cent for deep and ultra-deep waters for oil.  
|                                             | For gas:  
|                                             | • 80 per cent for conventional domains for oil  
|                                             | • 90 per cent for deep and ultra-deep waters for oil |
| **Signature bonus**                        | Negotiable |
| **Production bonus**                       | Negotiable |
| **Period extension bonus**                 | Not negotiable |
| **Renewal of exploitation authorisation/permit** | Not negotiable |
| **Proportional mining royalty**            | Negotiable with a minimum for oil:  
|                                             | • 7 per cent to 15 per cent in conventional areas  
|                                             | • 5 per cent to 12 per cent in deep and ultra deep offshore  
|                                             | Negotiable with a minimum for gas:  
|                                             | • 5 per cent to 10 per cent in conventional areas  
|                                             | • 2 per cent to 8 per cent for gas in deep and ultra deep offshore |
| **Production sharing**                     | For conventional areas: 1st tranche: 45 per cent minimum for the state  
|                                             | For deep and ultra waters: 1st tranche: 40 per cent minimum for the state |
| **Corporate tax**                          | 35 per cent deemed to be included in the above state's profit oil (no effective corporate income tax to pay) |
| **Support funds**                          | For support to hydrocarbons, for equipment of Hydrocarbons Administration, for training, for development of local communities, for reduction of impact of petroleum activities on environment – conditions to be set forth in the implementation decree or decrees and the PSC and likely to be negotiable |
| **Dismantling fund**                       | Fund domiciled in an agreed Gabonese bank or at the Central Bank |
| **Domestic market**                        | 15 per cent discount on fixed price |
| **Provision for diversified investments (PID)** | 1 per cent of the turnover, conditions to be set forth in the implementation decree or decrees |
| **Provision for hydrocarbons investments (PIH)** | 2 per cent of the turnover, conditions to be set forth in the implementation decree or decrees |
**iv  Revocation and expiry of licences**

The PSC shall remain in force for as long as there is at least one valid exclusive exploration authorisation or exclusive exploitation authorisation, subject to any early termination.

The PSC may be terminated by the administration if, after formal notice to the contractor, usually within the 30 day period after its receipt, the following events notably happen:

- refusal to provide to the Administration within the prescribed periods the information required under the PSC;
- failure to pay bonuses, royalties and contributions to the training of Gabonese nationals within the required periods of time;
- failure to pay within the required periods of time the proceeds from sale by the contractor of the government’s share of hydrocarbons;
- failure to deliver to the state its share of production in kind or the proportional mining royalty;
- suspension or restriction of, without legitimate reason, the exploitation activity; or
- failure to deliver, within the required periods of time, the parent company guarantee.

Pursuant to the 2019 Hydrocarbon Law, the recurrence of offences under the 2019 hydrocarbon law and production sharing contracts can be sanctioned with the withdrawal of an authorisation and the prohibition from conducting petroleum operations (notwithstanding any penalty due for these offences).

**IV  PRODUCTION RESTRICTIONS**

The state and contractor entitlements are shared according to PSC terms as mainly described in Section III, bearing in mind that the state may have in certain situations a preemptive right on oil sale. Any oil and gas transaction between the state and the contractor involving provision of hydrocarbons will be in any case set at the Gabonese official price established by the government on a quarterly basis based notably on international market price.

However, the PSC contractor is under an obligation to supply the domestic market with a portion of its hydrocarbons according to conditions provided within the PSC. The sale price of hydrocarbons for the domestic market will be equal to the official price set by the government minus a reduction of 15 per cent. The reduction constitutes a recoverable petroleum cost.

**V  ASSIGNMENTS OF INTERESTS**

While the administrative title to oil (exploration, exploitation authorisations or permits) cannot be transferred, interests deriving from the PSC can be transferred either directly or indirectly through change of control of contractor. Partial or total transfers of oil interests to a third party may happen, subject to the state authorisation and its preemptive right, if it is notably demonstrated that the assignee has good technical and financial reputation, the transaction does not jeopardise the state interests, does not impact the performance of petroleum operations or reduce the technical and financial capabilities of the contractor. Transfer and possible capital gain taxes need to be paid too.

Transfer of oil interests to affiliated companies are only subject to a declaration to the Hydrocarbons Administration.
The assignor must inform the Hydrocarbons Administration in writing, setting out notably the name, quality and nationality of the assignee, and all the indications relating to its financial and technical capacities, its legal status, and the form and financial conditions of the proposed transfer of the oil interest.

If the Hydrocarbons Administration does not raise any objection and if (1) the state does not exercise its pre-emption rights within a 60-day period, and (2) then GOC for a 45 day period, authorisation is usually deemed to be granted. After authorisation, a new licence is granted in the name of new partners on the block.

VI TAX

Various specific taxes and contributions apply to the oil sector:

a proportional mining royalties (depending on the daily production and type of fields involved) on the total available production;

b annual superficiary royalty (including during the exploration period);

c corporate income tax at 35 per cent deemed to be included in the share of the remaining production remitted to the state according to tranches provided within the PSCs;

d 3 per cent transfer taxes on assignments of interests;

e contributions to several funds:
  • the hydrocarbons fund;
  • the fund for state equipment;
  • the fund for local communities;
  • the fund for dismantling equipment; and
  • the fund for reduction of environmental impacts;

f 1 per cent reserve for diversified investments and 2 per cent reserve for hydrocarbons investments;

g bonuses regarding signature of PSC and its amendments, extension of period, production threshold;

h customs duties;

i VAT at zero per cent; and

j training support.

Tax incentives may apply for, in particular, marginal and mature fields as well as for gas development.

Apart from those specific hydrocarbons taxes, standard taxation remains, requiring the contractor notably to pay personal income tax of employees withheld by the oil company (from zero to per cent), wage tax (5 per cent), social contributions on wages (24.6 per cent), special solidarity contribution (1 per cent) and VAT (zero per cent and 18 per cent) on limited activities, and withholding tax on services (9.5 per cent and 10 per cent).

There are few double taxation treaties signed between Gabon and Belgium, France, Canada, Morocco, Central African states and certain West African states.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In addition to international treaties signed by Gabon on environment, Gabon also has its domestic code for sustainable development and an environmental code. The 2019 hydrocarbons law also provide for, for instance, the gas flaring prohibition and the requirement to dismantle installations at the end of exploitation. In order to secure these dismantling obligations, a support fund for the dismantling obligations needs to established by the operator from the beginning of production up to a percentage of the value of the contemplated dismantling obligations, to be provided within the PSC.

This support fund for dismantling obligations needs to be deposited in a Gabonese bank and co-managed by the state and the operator.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Until an upstream company move to exploitation period, it can only have a branch registered for two years, renewable, in Gabon. From exploitation, it has to incorporate a local company in which the state may acquire at market price a maximum of 10 per cent of shares.

Registration of a Gabonese branch usually takes about two weeks to be fully registered, while the incorporation of a Gabonese company by shares takes at least one month after foreign exchange regulations and foreign investment formalities have been completed.

ii Capital, labour and content restrictions

The new 2018 regional CEMAC Act on foreign exchange regulations needs to be considered for any financial flux and investment within and towards Gabon, in particular when it notably provides for certain restrictions on the foreign direct investment in local companies, the opening of foreign and local foreign currencies accounts and requires the repatriation of export proceeds through local bank accounts.

In addition and pursuant to a Gabonese Decree dated 16 May 2011, any non-Gabonese resident person who wants to invest in the Gabonese hydrocarbons sector through the direct or indirect holding of the control of a Gabonese company or the acquisition of the business of a company operating in Gabon needs to obtain prior authorisation from the Minister in charge of the economy. The Minister has two months to reply to such application, and we have never experienced any issue with this.

As in many emerging economies, local content is a key issue; it has become one of the key criteria for the Gabonese state to select its bidder in the tender process of block allocation. At similar economic and market conditions, preference should also be granted to national companies, in particular when subcontracting works, as well as for employment of nationals. While a 10 per cent ratio of expatriates is the standard rate of foreign employment in Gabon, due to the lack of local staff in certain oil and gas specialities, work permits granted to oil operators are sometimes given above this ratio upon provision of a file demonstrating the lack of local staff. In any case, after a certain period usually provided within the PSC, these expatriates should be progressively replaced by local and trained staff through notably pairing.

iii Anti-corruption

Gabonese law prohibits bribery and corruption under its Penal Code and its specific law on illicit enrichment according to usual international standards.
IX CURRENT DEVELOPMENTS

Thanks to the adoption of the new 2019 hydrocarbons law (while it needs to be completed by regulatory measures), international investors are back in Gabon. In early August 2019, Petronas signed two PSCs, while the end of the 12th bidding round for 35 other offshore blocks launched in October 2018 is expected to end in January 2020 with other foreign investors. In the meantime, other direct negotiations are progressing on certain other available onshore and offshore blocks, demonstrating the new attractiveness of new proposed economic and tax terms.
I INTRODUCTION

Germany produces little domestic oil and natural gas and relies heavily on imports. In 2018, only 2 per cent of oil and 6.4 per cent of natural gas were produced domestically while the rest of it had to be imported to cover domestic oil and gas consumption. Crude oil is mainly imported from Russia, Norway and European Union Member States. Natural gas comes mainly from Russia, Norway and the Netherlands.

Annual domestic oil and gas production has been declining steadily. In 2018, annual oil production amounted to 2.1 million metric tons, which represents a decline of about 6.6 per cent from 2017 levels while production of natural gas declined by about 13.1 per cent and amounted to 6.3 billion cubic metres. On 1 January 2019, Germany had proved and probable reserves of about 29 million metric tons of oil and 50.3 billion cubic metres of gas. Like in the year before, active drilling activities have continued to be at a low in 2018, with five exploration wells and 19 field development wells.

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1. Matthias Lang is a partner at Bird & Bird LLP. The author would like to thank Laura Linde, formerly a trainee at the firm and now at the Hertie School of Governance, for her contribution to this chapter.


Onshore oil and natural gas fields are mainly located in the northern part of Germany. More than 90 per cent of domestic gas and around one third of crude oil production and reserves are located in the federal state of Lower Saxony.8 Germany’s only two offshore oil and gas fields are located in the North Sea.9

Since around 1980, German energy policy has aimed to transition from conventional fossil fuels towards renewable energy sources. By launching the Energiewende (energy transition), Germany is reducing its dependency on oil and gas imports. However, while the legislature establishes necessary conditions to encourage investments into renewable resources, conventional energy sources like oil and natural gas ensure a secure energy supply to cover domestic needs.

A framework of mining laws covers the extraction of oil and gas and sets out requirements for a number of issues such as licensing, health and safety, environmental protection, compliance and monitoring. With regard to the use of unconventional fracking methods, a legislative package was adopted in February 2017 to impose a de facto prohibition on hydraulic fracking while also tightening requirements on conventional fracking methods.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The central legislative act regulating the exploration of oil and gas is the Federal Mining Act of 1980. European legislation on licensing, environment, health and safety was transposed into national law by amending the Federal Mining Act and by creating the Federal General Mining Ordinance of 1995. The Federal Mining Act is further accompanied by a number of ordinances on technical and procedural issues such as the Health and Safety Mining Ordinance and the Ordinance on Environmental Impact Assessments of Mining Projects.

The Federal Mining Act aims at ensuring availability of raw materials by effectively managing and promoting exploration, extraction and processing of mineral resources through licencing and approval procedures. The Act safeguards raw materials by prioritising the extraction of raw materials over other public interests and by providing that conflicting public law should be applied only to the extent that exploration and extraction are impaired as little as possible.10

The Federal Mining Act also aims to ensure the safety of mining operations and employees and to strengthen precautions against risks to human life, health, equipment and materials.11

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10 Section 48 Federal Mining Act. An English translation is available at www.gesetze-im-internet.de/englisch/_bergg/englisch_bergg.html#p0016. Please note that this translation is not binding and may not reflect the latest legislative changes.
11 Section 1 No. 2 and 3 Federal Mining Act.
ii Regulation
The requirements on licensing, health, safety and environmental protection are implemented and enforced through administrative acts as well as through compliance and monitoring mechanisms. While the Federal Mining Act is a federal law, the respective competent authorities of the federal states have the power to enforce the provisions of the Federal Mining Act. Federal authorities only have the power to enforce mining laws in the area of the continental shelf.

The competent authorities of the federal states in which mining activities take place can grant exploration and extraction licences. The licences entitle the holder to explore for and extract resources specified in the licence. Details and requirements to apply for such a licence may differ somewhat between the respective authorities in the different federal states. The application process may in practice also be delayed or accelerated depending on the specific political situation.

Mining authorities should approve the operating plan that the mining operator has to prepare in order to carry out the specified exploration or extraction. The approval procedure includes the assessment of the proposed measures with regards to safety and protection of workers, protection of the surface and prevention of damage to the public interest. The authorities also monitor compliance with the mining law provisions and may issue implementation measures to prevent risks. To further enforce the provisions of the Federal Mining Act the authorities can impose fines or penalties.

iii Treaties
Germany has entered into numerous multilateral and bilateral treaties on dispute resolution and trade liberalisation. Germany is also a party to double taxation treaties with more than 100 countries.

Germany is a contracting party to the Energy Charter Treaty. The Treaty aims at establishing a framework for energy security on the basis of open, competitive markets and sustainable development. Germany is also a contracting party to major trade liberalisation and investment protection agreements, such as the General Agreement on Tariffs and Trade (GATT), the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 1958 or the International Centre for Settlement of Investment Disputes Convention of 1965.

Germany is a Member State of the European Union and, therefore, also subject to the legal framework of the Union. Consequently, Germany is part of the European internal gas market as well as of the Energy Union, which the European Union’s Third Energy Package from 2009 established. Further, the Regulation on wholesale energy market integrity and transparency (REMIT) is directly applicable in Germany. The Regulation aims at identifying and penalising abusive practices in wholesale energy markets and has a direct effect on participants of the German gas market.

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12 Section 142 Federal Mining Act.
13 Sections 132 and 134 Federal Mining Act.
The European Union has also entered into the Comprehensive Economic and Trade Agreement (CETA) with Canada aiming to liberalise trade by reducing tariff barriers and establishing rules on investment protection. CETA provisionally entered into force on 21 September 2017, but before the provisions of CETA can take effect in the European Member States their national parliaments still have to approve the agreement.  

III LICENSING

Licensing of mining activities follows the principle of first come, first served. Old exploration and extraction rights or agreements as well as mining proprietorship concluded before the Federal Mining Act entered into force remained in force. Mines, mining concessions and other special rights regarding exploration and extraction of resources effective at the time the Federal Mining Act entered into force were also maintained.

In principle, the authorisation process for licensing follows a two-step procedure. First, the interested party has to apply for an exploration licence or extraction licence to explore and extract mineable resources. Applying for mining proprietorship is also possible. Mining proprietorship grants the same exclusive rights as the extraction licence, but in addition it extends to a right equivalent to a property right. Provisions of the German Civil Code on real property, therefore, apply to the ownership of mining proprietorship. To apply for mining proprietorship, the applicant must be in possession of an extraction licence for the resources and the field in question.

The application for exploration and extraction licences or mining proprietorship has to be made in writing to the competent authority. The application shall include, inter alia, specifications of the exact resource to be explored or extracted and detailed specifications of the mining area.

The Federal Mining Act differentiates between ‘freehold mineral resources’ and ‘freely mineable resources’, which can be explored and extracted. Freehold mineral resources are defined as the property of the landowner, whereas land-ownership does not extend to freely mineable resources. Freely mineable resources include hydrocarbons and any gases generated during the extraction process. The general principle is that an exploration licence is required for exploring freely mineable resources and an extraction licence or mining proprietorship is required for extracting these resources.

However, neither the exploration licence nor the extraction licences by themselves entitle the holder to actually conduct exploration or extraction activities. Actual exploration and extraction can only be carried out in accordance with an operating plan developed by

18 Section 149 Federal Mining Act.
19 Section 9(1) Federal Mining Act.
20 Section 13 No. 1 Federal Mining Act.
21 Section 10 Federal Mining Act.
22 Section 11 No. 1 and 2 Federal Mining Act.
23 Section 3(2) Federal Mining Act.
24 Section 3(3) Federal Mining Act.
25 Section 6 Federal Mining Act.
the mining operator and approved of by the competent mining authority.\(^{26}\) The second step for the authorisation of mining activities is, therefore, the approval of the operating plan for a specific mining activity by the competent authority.

There are four types of operating plans: (1) the framework operating plan; (2) the main operating plan, which is valid for a two-year term; (3) the special operating plan; and (4) the mine closure operating plan.\(^{27}\) The plans cover mining activities from the beginning of exploration up to the rehabilitation of the used lands after mining activities have been terminated. The mining operator is responsible for developing the operating plan and specifying necessary measures for operational safety of workers, preventing damage to resources whose protection is in the public interest, protecting the surface and providing for preparatory measures to restore usability of the site after mining activities have been terminated.\(^{28}\)

The duration of an exploration licence is limited to a maximum of five years.\(^{29}\) An extension for an additional three years can be granted if the exploration field could not be sufficiently explored despite ordinary and coordinated extraction. Extraction licences can be granted for periods that are appropriate for extraction in the individual case, but 50 years may only be exceeded if necessary for such investments ordinarily required for extraction.\(^{30}\)

The competent mining authority can deny an exploration licence on the grounds that the applicant has failed to present a realistic work programme that is adequate in type, scope, purpose and duration for the planned mining operations.\(^{31}\) Furthermore, the applicant has to be reliable and the licence will be denied if he or she cannot provide evidence that he or she has sufficient funds to carry out the intended mining activity or if the mining activity would impair resources whose protection is in the public interest or if overriding public interests exclude exploration and extraction within the entire licence area.\(^{32}\)

Extraction licences can be denied on additional grounds: (1) if the coordinates and depth of the mining site are not exactly specified and marked in a map; (2) if the applicant cannot prove that the location and characteristics of the resources permit their extraction; or (3) the technology and facilities required are adequate for the extraction within an appropriate time frame.\(^{33}\)

Exploration and extraction licences can be revoked if events occur after the granting of the licence that would have resulted in the denial of the licence in the first place.\(^{34}\) An exploration licence can also be revoked if exploration has not commenced one year after the licence was granted due to reasons the licence holder is responsible for or if scheduled exploration is interrupted for more than one year.\(^{35}\) For extraction licences, the time frame to commence extraction operations is three years before the licence can be revoked. However,
this does not apply if a later start of extraction is necessary for economic or technical reasons.\textsuperscript{36} Exploration or extraction licences can also be revoked partially or entirely at the request of the licence holder.\textsuperscript{37}

IV PRODUCTION RESTRICTIONS

Generally, there are no specific restrictions on oil and gas production in Germany. However, production restrictions can arise from environmental laws. Water and nature preservation laws prohibit the use of conventional fracking in water and mineral spring protection areas or lake and well regions for public drinking-water supply\textsuperscript{38} as well as in specified nature reserves.\textsuperscript{39} As Germany is an import nation for oil and gas, there are no restrictions, as such, on oil and gas exports. There are also no specific requirements for sales of production into local markets. The Federal Oil Stock Act may order that oil stocks are maintained at an amount corresponding to 90 days of average daily net imports in order to ensure a secure domestic supply of oil.\textsuperscript{40}

Although not a restriction as such, the general tax regime applies to oil and gas sales into local markets. Oil and gas prices are not subject to specific price setting laws, but rather are determined pursuant to market forces.

V ASSIGNMENTS OF INTERESTS

The Federal Mining Act specifies requirements for the transfer of mining rights. Exploration and extraction licences can be transferred and passed on to a third party, subject to the consent of the competent mining authority.\textsuperscript{41} Consent shall be provided in writing and can be denied, for example, if facts give reason to believe that the mining operator is unreliable or that he or she does not have sufficient funds to carry out the mining operation or if overriding public interests prohibit the exploration or extraction.\textsuperscript{42}

Subject to the approval of the competent mining authority, mining proprietorship can be sold to a third party in accordance with provisions of the German Civil Code on the law of obligations.\textsuperscript{43} Approval can only be denied if the sale is not in the public interest. If the legal transaction requires a notarial recording, approval can be granted prior to the recording.\textsuperscript{44} Approval is considered granted if permission was not denied within two months of receipt of the request for permission.\textsuperscript{45}

There is generally no payment required and the government has no first right of first refusal or preferential purchase rights in the event of a transfer.

\textsuperscript{36} Section 18(3) Federal Mining Act.
\textsuperscript{37} Section 19(1) Federal Mining Act.
\textsuperscript{38} Section 13a(1) No. 2 Federal Water Act.
\textsuperscript{39} Section 33(1a) Federal Nature Conservation Act.
\textsuperscript{40} Section 3(1) Federal Oil Stock Act.
\textsuperscript{41} Section 22(1) Federal Mining Act.
\textsuperscript{42} Section 22(1) Federal Mining Act.
\textsuperscript{43} Section 23(1) Federal Mining Act.
\textsuperscript{44} Section 23(2) Federal Mining Act.
\textsuperscript{45} Section 23(2) Federal Mining Act.
VI TAX

The Federal Mining Act contains specific provisions on royalties for the extraction of mineral resources. The standard percentage for mining royalties is set at 10 per cent of the average attainable market value.\(^{46}\) The governments of the federal states can issue ordinances to reduce or raise the percentage in five cases: (1) to prevent an overall economic imbalance; (2) to prevent risk to the competitive position of the exploration or extraction companies; (3) to ensure the supply of raw materials to the market; (4) to improve the utilisation of deposits for protecting other national economic interests; or (5) as long as the resources are used in the extraction process.\(^{47}\) Apart from royalties, taxes for the mining industry in Germany are principally subject to general provisions of German tax and revenue laws.

Other specific domestic taxes relate to the consumption of oil and gas products. The German Energy Tax Act, which implements the European Energy Tax Directive 2003/96/EC, provides for domestic consumption tax on heating oil as well as for fuels used in the transportation sector. The Energy Tax Act also contains specific tax exemptions for fuels used for the production of oil and gas.\(^{48}\)

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact assessment

An environmental impact assessment is required for commercial oil and gas production if the extracted daily amount exceeds 500 tonnes of oil or 500,000 cubic metres of natural gas.\(^{49}\) It is likewise required for the construction and operation of production platforms within coastal waters and the continental shelf.\(^{50}\) The use of hydraulic fracking for exploration and extraction of oil and gas as well as for scientific purposes also requires an environmental impact assessment.\(^{51}\)

If the planned mining operation requires an environmental impact assessment, the mining operator has to set up a framework operating plan that is subject to the approval of the competent mining authority.\(^{52}\) Details of the approval procedure are specified in the German Administrative Procedure Act. The approval procedure serves the purpose of taking the interests of affected parties and ecosystems into account early, even before the extraction of resources begins.

Environmental impacts also have to be taken into account when a mining operation is terminated. The termination of mining operations requires the mining operator to set out a closure plan that must include details of the technical execution and duration of the planned termination of mining operations.\(^{53}\) An operating log must accompany the closure plan.

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\(^{46}\) Section 31(2) Federal Mining Act.

\(^{47}\) Section 32(2) No. 3 Federal Mining Act.

\(^{48}\) Section 26 Energy Tax Act.

\(^{49}\) Section 1 No. 2 Ordinance on Environmental Impact Assessment for Mining Projects.

\(^{50}\) Section 1 No. 2b Ordinance on Environmental Impact Assessment for Mining Projects.

\(^{51}\) Section 1 No. 2a Ordinance on Environmental Impact Assessment for Mining Projects.

\(^{52}\) Section 52(2a) Federal Mining Act.

\(^{53}\) Section 53(1) Federal Mining Act.
setting out a geological description of the deposit and an inventory of resources, including mine dumps, as well as a description of the treatment facilities and any available chemical analysis. The mining operator is also required to specify details in the closure plan to ensure that necessary precautions to protect human health or life are taken, that resources whose protection is in the public interest will not be impaired and that the surface will be protected with respect to personal safety and the public interest. Further, it must be ensured that any waste resulting from operations is properly used or removed and preparatory measures for restoring usability of the surface have been taken. If a closure plan is developed for a mining area on the continental shelf or in coastal waters, damaging effects on the ocean have to be kept to an absolute minimum.

ii Conventional and unconventional fracking methods

In Germany, a difference is made between ‘conventional’ and ‘unconventional’ fracking methods. Conventional fracking has been used in Germany since the 1960s to extract natural gas from sandstone rock formations. About one-third of the country’s natural gas production comes from this proven method of natural gas extraction. Unconventional fracking refers to the extraction of natural gas from clay, shale, marl and coal formations. As opposed to the long-term experience with conventional fracking, there has been no long-term experience with unconventional fracking in Germany so far.

Unconventional fracking technologies are politically controversial in Germany, particularly with regard to safe drinking water and environmental protection. The discussion is often focused on dangers and risks associated with the use of unconventional fracking methods with little regard for potential benefits. A legislation package, adopted in February 2017, ensures the protection of the environment, health and other interests of those affected by unconventional fracking methods. The legislation also transposes European requirements for safety and environmental standards into Germany’s national laws.

The legislation mainly includes amendments to the Federal Water Act, the Federal Nature Conservation Act, the Federal Mining Act and the Ordinance on Environmental Impact Assessment for Mining Projects. The amendments tighten existing requirements in mining and water laws to provide for a better protection of drinking water and health. All fracking projects relating to the exploration of oil and gas, regardless of the depth of the extraction project, are subject to an environmental impact assessment.

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54 Section 53(2) Federal Mining Act.
55 Section 55(1) No. 3 to 5 Federal Mining Act.
56 Section 55(1) No. 6 and 7 Federal Mining Act.
57 Section 55(1) No. 13 Federal Mining Act.
61 Section 1 No. 2a Ordinance on Environmental Impact Assessment for Mining Projects.
The fracking legislation package contains tighter requirements for conventional fracking methods. The legislation prohibits conventional fracking projects in water and mineral spring protection areas and lake or well regions for public drinking-water supply as well as in specified nature reserves.

Unconventional fracking is prohibited in shale, marlstone, clay rock and coal seam rock formations until 2021. After this date, the German parliament has to decide whether the prohibition shall remain in place. Unless Parliament takes specific action, the prohibition will remain in place. However, four test drillings are allowed nationwide for scientific purposes only, and they require the approval of the government of the respective federal state in which the fracking project shall take place. Test drillings would be monitored by an independent expert commission that was established in May 2018, but there have been no requests for test drillings so far. The expert commission will, therefore, focus on evaluating and summarising existing studies to outline the state of the art in fracking science and technology and to establish the foundation for Parliament’s decision on the extension of the fracking ban in 2021. However, the establishment of the expert commission has fuelled the discussion about the environmental risks of fracking, and opponents have called for a complete fracking ban. It remains to be seen if there will be any requests for test drillings in the next few years and what kind of implications they will have on the discussion about fracking and further restrictions on water and nature-preservation laws.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

As Germany is a Member State of the European Union, establishment by nationals of other EU Member States is not restricted under the fundamental principle of freedom of establishment. Neither are foreign investors from a member country of the European Free Trade Association (EFTA – including the non-EU Member States Iceland, Liechtenstein, Norway and Switzerland) subject to any restrictions regarding establishment or investments.

Foreign investors from non-EFTA countries are subject to restrictions and obligations as set out in the Foreign Trade and Payments Act and the Foreign Trade and Payments
Ordinance. Further restrictions can be imposed on foreign investments if vital needs in (parts of) Germany need to be secured to protect health and life of human beings.

A number of amendments on foreign investment legislation in 2017 and 2018 enhanced the veto right of the Federal Ministry of Economic Affairs and Energy on foreign investments. The amendments included an extension of the power of the Federal Ministry of Economic Affairs and Energy to examine whether public order or security is endangered if a non-EU resident acquires a domestic company or directly or indirectly participates in a domestic company. Further, the examination right was extended and specified to specific entities such as operators of critical infrastructure, which includes the oil and gas sector. While the 2017 amendments allowed the Ministry to examine acquisitions in which a foreign investor acquires at least 25 per cent of the voting rights in the domestic company, the amendments of December 2018 further extended the Ministry’s veto right to examine acquisitions of at least 10 per cent of domestic operators of critical infrastructure and other specified entities. It remains to be seen how the extension of the veto right will affect foreign investments in the German oil and gas industry. In any event, the examination right will be applied on a case-by-case basis, and so far, the Federal Ministry of Economic Affairs and Energy has not exercised its veto right.

Foreign investment could also face restrictions subsequent to secondary, extraterritorial effects of US sanctions on Iran and on any company using the dollar or involved in the US market. Iranian exports to Germany, including energy exports, have already declined by more than 40 per cent. To soften the impact of the sanctions, Germany, together with France and the UK, started to set up a special purpose vehicle in January 2019 to still be able to import oil and other products from Iran. The full force of the impact of these sanctions on Germany, especially of those curbing Iranian energy exports, remain to be seen.

ii Capital, labour and content restrictions

Freedom of capital movement and freedom of movement for workers are fundamental EU principles that generally allow workers and capital to move unrestricted between EU Member States. However, workers from EU Member States have to comply with domestic reporting obligations. The Act on the Residence, Economic Activity and Integration of Foreigners in

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71 An English translation is available at www.gesetze-im-internet.de/englisch_awv/englisch_awv.html. Note that this translation is not binding and may not reflect the latest legislative changes.
72 Section 5(2) Foreign Trade and Payments Act.
73 Sections 5(4) and 4(1) No. 5 Foreign Trade and Payments Act.
74 Section 55(1) Foreign Trade and Payments Ordinance.
75 Section 55(1) No. 1 to 3 Foreign Trade and Payments Ordinance.
76 Section 56(1) No. 1 Foreign Trade and Payments Ordinance.
77 See Reuters news article (10 May 2019), DIHK – Deutsche Exporte in Iran um mehr als 50 Prozent eingebrochen, https://de.reuters.com/article/deutschland-iran-dihk-idDEKCN15G0BX.
79 Article 63 Treaty on the Functioning of the European Union.
80 Article 45 Treaty on the Functioning of the European Union.
the Federal Territory provides that non-EU workers may be granted a residence title for the purpose of taking up employment if the Federal Employment Agency granted its approval. The Federal Employment Agency can impose specified restrictions on the residence title.

Non-EU members are subject to reporting requirements relating to assets of a domestic company in which a foreign national participates or that is dependent on several commercially associated foreigners or on assets of domestic branches and permanent establishments of foreign companies. The asset reports shall be submitted once a year to the German Central Bank by electronic means.

Exceptions from reporting requirements apply if the total balance sheet of the domestic company in which the foreign national participates or business assets ascribed to the domestic branch or permanent establishment do not exceed €3 million. Reporting requirements are also not applicable if the domestic resident is unable to access relevant reporting documents for actual or legal reasons or if the domestic or dependent domestic company in which commercially associated foreigners participate is not aware that the foreign nationals are commercially associated.

iii Anti-corruption

The German Criminal Code generally provides for measures against bribing public officials, European public officials or persons entrusted with special public service functions. The Criminal Code penalises the acceptance, offering, promising or granting of a bribe. Sanctions for the offeror and the receiving person can include imprisonment of up to five years or fines in less serious cases.

Corporations as such cannot be subject to criminal sanctions. However, the Criminal Code extends corporate liability to the responsible representative: Criminal offences committed within the corporate structure of a legal entity will be attributed to: (1) the responsible person in his or her capacity as an organ authorised to represent a legal entity; (2) a partner authorised to represent a partnership with independent legal capacity; or (3) as a statutory representative of another.

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81 Section 18(2) Act on the Residence, Economic Activity and Integration of Foreigners in the Federal Territory. An English translation is available at https://www.gesetze-im-internet.de/englisch_aufenthg/englisch_aufenthg.html. Note that this translation is not binding and may not reflect the latest legislative changes.

82 Section 65 Foreign Trade and Payments Ordinance.

83 Sections 71(2) and 72 Foreign Trade and Payments Ordinance.

84 Section 65(4) No. 1 and 2 Foreign Trade and Payments Ordinance.

85 Section 65(4) Foreign Trade and Payments Ordinance.

86 An English translation is available at https://www.gesetze-im-internet.de/englisch_stgb/englisch_stgb.html. Note that this translation is not binding and may not reflect the latest legislative changes.

87 Sections 331 to 336 Criminal Code.

88 Section 14 Criminal Code.
IX CURRENT DEVELOPMENTS

i Pipelines and LNG

The total length of Germany’s gas pipeline network is about 511,000km. The pipelines are used to import and distribute gas around the country as well as to transport gas to other EU Member States. There are 16 gas transmission system operators currently operating on the German gas market while other players include operators of distribution systems or storage facilities. Germany’s gas market is part of the EU Internal Energy Market, and market participants are not only subject to national legislation but also to EU regulations. Rules from the EU’s Third Energy Package on unbundling for operators of gas transmission systems and storage system operators, therefore, affect gas market participants in Germany.

As Germany relies on gas imports, the pipeline network will be further expanded to ensure a reliable gas supply that meets demand. Expansion projects include the Nord Stream 2 pipeline, which will allow the transport of even more natural gas directly from Russia to Germany across the Baltic Sea. The Nord Stream 2 project will result in the longest offshore gas pipeline in the world. However, the expansion is environmentally and politically controversial. Both the European Parliament and Commission have expressed their opposition to the project and adopted revised rules for the EU’s internal gas market, which Member States have to transpose into national laws by 24 February 2020. Nord Stream 2 will now have to comply with the EU’s gas market rules on third-party access, tariff regulation, ownership unbundling and transparency. Exemptions are also possible under the new rules, but it remains to be seen if they would be applied to Nord Stream 2. At the time of writing, it is unclear to what extent US sanctions will affect or even derail Nord Stream 2. Conceptually, both the US Countering America’s Adversaries Through Sanctions Act (CAATSA) and the US Protecting Europe’s Energy Security Act (PEESA) appear to have disruptive potential. Despite the controversies surrounding the project, the construction of the pipeline is progressing on German territory. Following approval by the relevant public authorities, important parts of the pipelines have already been laid.

91 Article 15 Directive 2009/73/EC.
Another expansion of the pipeline grid focuses on the ‘Southern Gas Corridor’. The Trans Adriatic Pipeline shall supply Europe and, only indirectly, Germany with gas from Azerbaijan to Europe. With more than 88 per cent of the pipeline already completed, the project remains on track to deliver gas to Europe from 2020 onwards.

While Germany relies heavily on gas imports, other methods of transportation and storage of gas may become increasingly important. LNG (liquefied natural gas) is particularly beneficial for transportation and storage, and, therefore, access to LNG terminals plays an increasing role. In February, the government held in its coalition agreement that Germany should be turned into a location for LNG infrastructure. Germany does not have its own reception terminal for LNG yet, but access to LNG can be secured through Belgium, the Netherlands and other European countries. German gas companies have already begun to acquire stakes in LNG terminals abroad and reportedly plan to acquire further capacities in Belgium, France and the Netherlands. Furthermore, plans to build and operate Germany’s first LNG terminal in northern Germany are currently being developed. The final investment decision is scheduled for the end of 2019, and after a three-year construction phase the terminal is supposed to go online by the end of 2022. While the International Energy Agency predicts a 20 per cent rise of LNG imports to Europe by 2040 from 2016 levels, Trump predicts that Europe will become a ‘massive buyer of [US] LNG’, also in order to reduce dependence on Russia. It remains to be seen whether US LNG will be sufficiently commercially attractive for that to happen.

**ii Storage**

Germany has the world’s fourth-largest gas-storage capacity, which is also the largest within the EU. The volume of usable working gas was 24.3 billion cubic metres in 2018. Natural gas storage facilities cannot only balance short-term fluctuations of demand, but they also play an important role for the security of supply. Theoretically, the total storage

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To further ensure a secure gas supply, a number of planned projects have already been realised or are in progress, which would increase the storage volume up to 27.7 billion cubic metres.104

iii Energiewende

The Energiewende and declining production dominate the debate in Germany about further reducing dependency on oil and natural gas and imports. However, conventional oil and gas resources will continue to ensure a secure energy supply at least over the next few years. The transition from conventional fossil fuels to renewable energy sources also includes energy efficiency measures that further aim at being independent from oil and gas sources. National legislation with regard to energy efficiency measures as well as oil and gas will also be impacted by the further implementation of the European Union’s internal gas market and the Energy Union.

iv Digitalisation

The digital age brings further challenges to the oil and gas industry in Germany. The International Energy Agency estimates that production costs could be decreased by up to 20 per cent while technically recoverable resources could be increased by 5 per cent.105 New automated technologies, better sensors for exploration, big data analytics or visualising software are already used for more efficient oil and gas production in Germany. However, further investments in innovative technologies are needed to improve German oil and gas production and the legislature will have to work together with industry stakeholders and other interest groups to establish a sound legal framework to encourage the necessary investments.
INTRODUCTION

Historic overview

The upstream oil and gas activities in Ghana consist of exploration, development and production of oil and gas. These activities are undertaken in five sedimentary basins within Ghana’s territorial areas made up of the Tano Basin and Cape Three Points Basin in the Western Region (mostly referred to together as the Western Basin), the Saltpond Basin in the Central Region, the Accra/Keta Basin and the Inland Voltaian Basin. The Western Basin, Saltpond Basin and Accra/Keta Basin are all offshore and have been explored. The Inland Voltaian Basin is onshore and has not been really explored.

The exploration of hydrocarbons in Ghana dates as far back as the late seventeenth century. The first recorded hydrocarbon exploration was undertaken by West Africa Oil and Fuel Company in 1896. From 1905 to 1925, other companies that engaged in upstream activities included Société Française de Pétrole, African and Eastern Trade Corporation and Gulf Oil Company. By independence in 1957, 21 wildcats had been drilled for exploration. Key among these was the first offshore discovery by Signal-Amoco Consortium in the Saltpond Basin, named the Saltpond Field, which started production in 1978. The production at the Saltpond Field peaked at 4,500 barrels of oil per day during its production stages and was shut down in 1985. By the mid-1980s, the total well count in Ghana (onshore and offshore) was 54.

Legislative overview

In the mid-1980s, the government introduced the first legislative framework for upstream oil and gas activities in Ghana. Three main pieces of legislation were enacted by the government to regulate the upstream oil and gas activities. Chief among the reforms was the passage of the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64), which established the Ghana National Petroleum Corporation (GNPC) as the national oil corporation to champion state activities in the upstream oil and gas sectors. In addition, the now repealed Petroleum (Exploration and Production) Law, 1984 (PNDCL 84) was enacted to regulate...
exploration and production activities as well as provide the framework for engagement of international oil firms by the government to undertake exploration and production activities. Lastly, the Petroleum Income Tax Law 1987 (PNDCL 188) was passed to regulate operations and taxation in the upstream oil and gas sector. Of the three pieces of legislation, PNDCL 84 and the PNDCL 188 have been repealed and replaced with new pieces of legislation that are currently applicable. This is discussed further below.

The Fourth Republican Constitution, which came into force in 1992, provides that ‘every mineral in its natural state in, under or upon any land in Ghana, rivers, water course throughout Ghana, the exclusive economic zone, any area covered by the territorial sea or continental shelf in the Republic of Ghana is the property of the Republic of Ghana and is vested in the President on behalf of, and in trust for the people of Ghana’.\(^7\) As a check on the powers of the President to control and manage the resources on behalf of the people of Ghana, the Constitution requires parliamentary approval for all transactions involving the grant of a right for the exploitation and production of natural resources in Ghana and further mandated the establishment of specific commissions to be responsible for the regulation and management of the utilisation of the natural resources and the coordination of the relevant policies.

Upon the discovery of oil in commercial quantities offshore Ghana in 2007, the Petroleum Commission Act, 2011 (Act 821) was subsequently passed to set up the Petroleum Commission as the regulator to coordinate activities in the upstream petroleum industry in accordance with the Constitution.\(^8\) In addition, the Petroleum Revenue Management Act, 2011 (Act 815) as amended by Petroleum Revenue Management (Amendment) Act, 2015 (Act 893), was enacted to provide the framework for management of petroleum revenues. In 2016, the Petroleum (Exploration and Production) Act, 2016 (Act 919) (the E&P Act), was passed to replace the PNDCL 84, as the primary legislation for the regulation of petroleum activities in the upstream sector. Also, the Income Tax Act 2015 (Act 896) as amended provides a regime for the taxation of income of contractors and subcontractors in the sector.

In order to support the implementation of the key laws in the sector, the government through the Minister of Energy (the Minister) and the Petroleum Commission have enacted a number of regulations, guidelines and developed policies for the sector. These include the following:

\(a\) the Petroleum (Local Content and Local Participation) Regulations, 2013 (LI 2204);
\(b\) the Petroleum Commission (Fees and Charges) Regulations, 2015 (LI 2221);
\(c\) the Petroleum (Exploration and Production) (Measurement) Regulations, 2016 (LI 2246);
\(d\) the Petroleum Exploration and Production-Data Management Regulation, 2017 (LI 2257);
\(e\) the Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (LI 2258);
\(f\) the Petroleum (Exploration and Production) (General) Regulations, 2018 (LI 2359);
\(g\) the Energy Sector Strategy and Development Plan;
\(h\) the Gas Master Plan;
\(i\) the Gas Pricing Policy Guidelines to the Petroleum (Exploration and Production) (Measurement) Regulations;

\(^7\) Article 257(6) of the 1992 Constitution.
\(^8\) Prior to the establishment of the Petroleum Commission, the function was somehow performed by the national oil company in addition to its mandate as the national oil corporation.
Guidelines for the formation of joint venture companies in the upstream petroleum industry of Ghana (March 2016);

Guidelines on Submission of Proposed Contracts to the Petroleum Commission (23 February 2018); and

the Oil and Gas Insurance Placement for the Upstream Sector.

### Industry and foreign investment overview

The establishment of the national oil corporation, the GNPC and the passage of the above legislation have laid the foundation and provided the framework for activities in the industry. Efforts by the GNPC over the years since its establishment has led to an increase in activities in the sector to find more oil. This has resulted in the execution of a number of agreements between the GNPC, the government and international oil companies (IOCs) to fund, acquire, process and interpret data on seismic activities from the offshore basins. As earlier noted, PNDCL 84 provided the initial framework for engagement of international oil companies as it set the terms and conditions that must be in a contract for such an engagement. In furthermore of standardisation of the contract form for the engagement, the country has adopted a model petroleum agreement based on international best practice to attract IOCs.

The IOCs currently involved in the upstream oil and gas sector include Kosmos Energy, Hess Corporation, Tullow UK, Norsk Hydro Oil, Heliconia Energy Resources, Anadarko, ENI, Aker Energy, AGM Petroleum and ExxonMobil. These investments have resulted in deepwater offshore exploration activities.

The first significant deepwater oil discovery in Ghana was in 2007 by Tullow Oil, Kosmos Energy, Anadarko Petroleum and EO Group in the offshore Tano/Cape Three Points Basin of the Ghanaian continental shelf, christened the Jubilee Fields. The Jubilee Fields is a unitised field located 65km offshore, south-east of Takoradi in the Western Region of Ghana between the Deepwater Tano and West Cape Three Points blocks. The Deepwater Tano block is currently held by the Jubilee Partners, a consortium of IOCs in the following proportions: Tullow Oil (49.95 per cent), Kosmos Energy (18 per cent), Anadarko (18 per cent), the GNPC (10 per cent) and Sabre Oil and Gas (4.05 per cent). West Cape Three Points is also held by Tullow (22.9 per cent), Kosmos (30.88 per cent), Anadarko (30.88 per cent), the GNPC (10 per cent), Sabre Oil and Gas (1.85 per cent), and EO Group (3.5 per cent). The field is operated by Tullow Oil as the mandated operator. The field has proven reserves of approximately 3 billion barrels and is currently estimated to be producing approximately 120,000 barrels of oil per day.

The success of the Jubilee Field has immensely reduced the perceived risk involved in investing in upstream oil and gas activities in Ghana resulting in increased exploration activities offshore the Western Basin. The key discoveries include Tweneboa-1 (2009), Tweneboa-2 (2010), Enyenra (formally Owo) (2010), Ntomme (2012) and Wawa (2012) in the Deepwater Tano block; Mahogany Deep (2009), Teak-1, Teak-2 (2011) and Akasa (2011) in the West Cape Three Points block;

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9 National Energy Policy (February 2010), Ministry of Energy.
10 Ghana Gazette, No. 5, 2014.

In May 2013, the plan for the development of the Tweneboa Dzata-1 (2010), Enyenra and Ntomme (TEN) fields, which cover an area of more than 800km², was approved by the government. Production has commenced from the TEN fields, and the first oil was delivered to the FPSO (floating production storage and offloading vessel) John Atta Mills in August 2016.

In 2012, ENI announced the first oil and gas discovery in the Offshore Cape Three Points (OCTP) block, also located in the Tano Basin. Through its Ghanaian subsidiary, ENI operates the Sankofa and Gye-Nyame fields with its partners Vitol Upstream Ghana Limited and GNPC. The project is located approximately 60km offshore west coast of Ghana and is estimated to hold about 41 billion cubic meters of non-associated gas and 500 million barrels of oil. Commercial operations commenced with the flow of the first oil from the Sankofa Gye Nyame oilfields through the FPSO John Agyekum Kufuor in July 2017.\(^\text{13}\) Gas production commenced in June 2018, and the field is expected to produce 180 million cubic feet of gas per day for 15 years.\(^\text{14}\)

On 23 September 2017, the Special Chamber of the International Tribunal for the Law of the Sea (ITLOS) gave its judgment in Dispute concerning delimitation of the maritime boundary between Ghana and Côte d’Ivoire in the Atlantic Ocean (Ghana/Côte d’Ivoire). The litigation was originally commenced by Ghana in Germany at the ITLOS by an application initiating arbitral proceedings under Annex VII of the United Nations Law of the Sea Convention (the Convention) after Côte d’Ivoire began laying claim to some offshore oil concessions and adjoining seabed being developed and exploited within Ghana’s territory.\(^\text{15}\) Côte d’Ivoire, in February 2015, had filed for preliminary measures urging the tribunal to suspend all activities on the disputed area until the definitive determination of the case and following legal and technical representations by both countries on 29 and 30 March 2015, the ITLOS Special Chamber in Hamburg, Germany ruled in April 2015 that ongoing projects in the disputed fields, including the US$7.5-billion TEN project could proceed while the substantive case was being dealt with, Ghana was ordered not to start new explorations within the disputed area. The Special Chamber finally concluded that there is no tacit agreement between Ghana and Côte d’Ivoire to delimit their territorial sea, exclusive economic zone and continental shelf both within and beyond 200 nautical miles. It rejected Ghana’s claim that Côte d’Ivoire is estopped from objecting to the ‘customary equidistance boundary’ and further concluded that there is no relevant circumstance in the present case which would justify an adjustment of the provisional equidistance line. Accordingly, the Special Chamber ruled on the relevant delimitation line for the territorial sea, the exclusive economic zone and the continental shelf within 200 nautical miles.\(^\text{16}\)

\[^{13}\] ibid.
\[^{15}\] Judgment of the International Tribunal for the Law of the Sea, Year 2017 (23 September, 2017); Dispute Concerning Delimitation of the Maritime Boundary between Ghana and Côte d’Ivoire in the Atlantic Ocean (Ghana/Côte d’Ivoire).
Following the ITLOS ruling in 2017, Tullow received notification from the government to recommence drilling in the TEN fields, and a multi-year incremental drilling programme started in 2018, seeking to ramp up production from the TEN fields to utilise the full capacity of the FPSO and sustain this over a number of years. Again, in October 2017 the government approved the Greater Jubilee Full Field Development Plan, allowing Tullow and its joint venture partners to prepare for a multi-year incremental drilling programme that integrates the nearby Mahogany and Teak discoveries in the West Cape Three Points Block with the Jubilee Field.

From 2013 to date, at least 12 exploration licences have been issued to other players in the industry, including Heritage Oil, AGM Petroleum, Britannia-U, Sahara Energy Fields, Camac Energy and Springfield. New discoveries that have been appraised include Wawa (Tullow), Mahogany Deep, Teak and Akasa (Kosmos Energy) Paradise, Hickory North, Almond, Beech, Cob, Pecan PN-1 and Pecan South 1A (Hess Corporation/Aker Energy).

Another investment activity worth mentioning relates to the activities in the gas sector. In 2011, the Ghana Gas Company Limited (GGCL) was established by the government as a private limited liability company with responsibility for building, owning and operating infrastructure required for the gathering, processing, transporting and marketing of natural gas resources in the country. The government has now transferred its shares in GGCL to the GNPC, which makes GGCL a subsidiary of the GNPC. This is in line with the policy of the government to make the GNPC the national aggregator of gas in Ghana for better and efficient management of gas resources. It is estimated that Ghana has approximately 22.65 billion cubic metres of proved reserves of natural gas in its oil fields.\(^{17}\) To ensure the safe and optimal use of natural gas, associated gas and natural gas liquids (NGL) from the oil fields, GGCL entered into an engineering procurement construction and commissioning agreement with SINOPEC in 2012 for the development of the Western Corridor Gas Infrastructure Development Project. The first phase of the project was commissioned in September 2015 and consists of an offshore pipeline, an onshore pipeline, a gas processing plant and a NGLs export system at Atuabo in the Western Region of Ghana. At full capacity, the facility is expected to produce 107 million standard cubic feet of lean gas, 500 tonnes of LPG, 80 tonnes of pentane and 45 tonnes of condensates daily.\(^{18}\) The project is currently connected to the gas infrastructure to the West Africa Gas Pipeline to enable the reverse flow of gas between the two lines.

In October 2018,\(^{19}\) the government launched the country’s maiden oil and gas licensing bid rounds, with six blocks, all in Tano/Cape Three Points (Western Basin) being placed on offer.\(^{20}\) The bidding round attracted multinational oil companies such as ExxonMobil, British Petroleum, Eni/Vitol, China National Offshore Oil Corporation, Qatar Petroleum, Aker Energy, Cairn Energy, Global Petroleum Group and First E&P. Sixteen oil and gas companies were initially selected in early 2019 to participate in the final stage of the oil and gas licensing round. Three of the oil blocks (2, 3 and 4) were selected to undergo a competitive bidding

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\(^{19}\) https://www.petrocom.gov.gh/2019/05/bids-for-oil-blocks-licensing-round-to-be-opened-on-may-21-14-companies-ving-for-five-blocks/.

process while two blocks (5 and 6) were to be undertaken by direct negotiations. Block 1 was, however, reserved for the GNPC. Two companies were disqualified, one for bidding for the block reserved for GNPC and the other for not meeting financial obligations. Also, ExxonMobil and British Petroleum later withdrew from the contest without assigning reasons. The government, on 27 June 2019 announced the winners of blocks 2 and 3 as First E&P Ltd/Elandel Energy Ghana Ltd and Eni/Vitol respectively.

II LEGAL AND REGULATORY FRAMEWORK

As already indicated, under the Constitution of Ghana, all untapped natural resources including oil and gas resources are vested in the President of Ghana for and on behalf of the people of Ghana. This is restated in the E&P Act. Therefore, the right to explore and develop such resources is subject to agreement or licence granted by the government (acting through the Ministry of Energy) and approved by Parliament. Initial petroleum activities in Ghana were governed by the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64), which constitutes an establishing instrument of the national oil corporation and the Petroleum Income Tax Act, 1987 (PNDCL 188). However, owing to increased activities in the upstream oil and gas sector after the commercial discoveries in the deepwaters, various regulatory reforms were initiated. This resulted in the enactment of the Petroleum Commission Act 2011 (Act 821), the E&P Act that provides an overarching framework, and the Petroleum (Local Content and Local Participation) Regulations 2013 (LI 2204) enacted to ensure local participation in the sector given the increase in the activities of foreign-owned entities in the sector, among others. There is also the Petroleum Revenue Management Act 2011 (Act 815) that governs the use of petroleum revenue accruing to the state from petroleum exploration. These laws are in addition to other regulations, directives and guidelines issued to guide operations in the sector.

The primary laws governing the upstream oil and gas sectors are the E&P Act and the Ghana National Petroleum Corporation Act, 1983 (PNDCL 64) and a taxation regime under the Petroleum Income Tax Act, 1987 (PNDCL 188) and the Income Tax Act, 2015 (Act 896) as amended.

i Domestic oil and gas legislation

The main legislation relating to the upstream oil and gas sector is as follows.

The Ghana National Petroleum Corporation Act, 1983 (PNDCL 64)

The first major activity to set the stage for regulatory reform of the upstream sector was the establishment of the GNPC under PNDCL 64. The GNPC is established as the national oil corporation charged with the responsibility to explore, develop, produce and dispose of hydrocarbons.

The law also mandated GNPC to advise government on oil and gas matters and to promote the exploration and orderly development of the petroleum resources of Ghana. In effect, the GNPC was created as a regulator and operator performing both regulatory and commercial functions under the supervision of the Ministry of Energy. At the earlier stages,
the GNPC led the effort to acquire data to establish Ghana’s reserves potential, and also led efforts to market the potential to IOCs interested in investing in the upstream sector in Ghana. However, the dual roles played by GNPC created conflict in the upstream sector as it seems to be a regulator and a player in the sector. This conflict, or potential conflict, was addressed in later regulatory reform; with the passage of the Petroleum Commission Act, 2011 (Act 821), which transfers the GNPC’s regulatory functions to the Petroleum Commission. Currently the GNPC is a commercial operator and the holder of government interests in petroleum operations in Ghana. It is also the national aggregator of natural gas from upstream operators to service the local market. Under the Petroleum Revenue Management Act, a specific percentage of the net cash flow from the carried and participating interests of the state is ceded to the GNPC to fund its operations.

The Petroleum (Exploration and Production) Act, 2016 (Act 919)
The E&P Act is the main legislation that regulates the grant of licence for upstream oil and gas activities, and regulates the exploration, development and production of petroleum in Ghana. The Act, in line with the Constitution, provides that petroleum existing in its natural state within Ghana is the property of Ghana and is vested in the President on behalf of the people of Ghana. The Act also permits the Minister to grant rights and enter into agreements for the exploration and production of oil and gas subject to the ratification of such rights or agreements by Parliament. The Act further mandates the Minister and the Petroleum Commission to develop regulations on safe construction, health and safety, product standard, reference maps for oil blocks, competitive bidding and terms and conditions of petroleum agreements.

Except in the case of the GNPC, any person who intends to engage in the exploration, development and production of petroleum can only do so in accordance with a petroleum agreement entered into between that person and the government of Ghana and the GNPC. Under the Act, a petroleum agreement can only be entered into after an open, transparent and competitive public tender process. However, the Minister may, on stated grounds, enter into a petroleum agreement without going through a tender process.

The Act mandates the Minister to prepare a reference map showing areas of potential petroleum fields within Ghana divided into numbered areas (blocks). Subject to rights granted to other entities under petroleum agreements entered into, the GNPC has the right to undertake exploration, development and production of petroleum over the blocks declared by the Minister as open for petroleum operations. Prior to exploration activities, the GNPC or the contractor must submit to the Minister for approval, a development plan in respect of a petroleum field to be developed directly by the GNPC or the contractor, as the case may be.

The essential terms and conditions that must be in a petroleum agreement are prescribed under the E&P Act. The Act prohibits the assignment of petroleum agreements, directly or indirectly, without the written consent of the Minister. The essential provisions of the Act cover the following:

- the power of the Minister to open an area for petroleum activities;\(^23\)
- the power of the Minister to close an area or redefine the boundaries;\(^24\)

\(^{23}\) Section 7 of Act 919.

\(^{24}\) Section 8 of Act 919.
that petroleum agreements must be entered into in accordance with an open, transparent and competitive public tender process; 25

d the power of the Minister to grant a petroleum reconnaissance licence for a period of not more than three years renewable for another two years; 26

e the right to review terms and conditions of the petroleum agreement owing to material change in circumstances; 27

f the right of the Minister to approve an operator before the execution of a petroleum agreement; 28

g the pre-emptory right of the GNPC to acquire the interest of a contractor under a petroleum agreement within 90 days of notification of intention to dispose of interest; 29

h any borrowing exceeding US$30 million for the exploration, development and production is subject to the approval of Parliament and must comply with the Petroleum Revenue Management Act, 2011 (Act 815); 30

i the right of a contractor to submit a proposal to relinquish a contract area or part of a contract area; 31

j the minimum work and expenditure obligations to be fulfilled by the contractor during the initial exploration period; 32

k transfer to the GNPC of physical assets purchased, installed, constructed by the contractor for petroleum operations and the cost of which is included in the exploration of expenditures; 33

l the requirement of a permit for exploration drilling and an annual permit for the production of petroleum; 34

m the requirement of a licence to install and operate facilities for the transportation, treatment and storage of petroleum; 35

n the establishment of a petroleum register for petroleum agreements, licences, permits and authorisations; 36

o the right of the Minister to require a licensee, contractor or subcontractor to provide security for the fulfilment of its obligations under an agreement; 37

p the establishment of a local content fund; 38

q pollution damage, liability of the polluter; 39

25 Section 10 of Act 919.
26 Section 9 of Act 919.
27 Section 20 of Act 919.
28 Section 13 of Act 919.
29 Section 18 of Act 919.
30 Section 10(15) of Act 919.
31 Section 22 of Act 919.
32 Section 23 of Act 919.
33 Section 19 of Act 919.
34 Section 24 of Act 919.
35 Section 38 of Act 919.
36 Section 56 of Act 919.
37 Section 58 of Act 919.
38 Section 64 of Act 919.
39 Section 83 of Act 919.
payment of income tax in accordance with the laws of Ghana except as modified in the agreement;\textsuperscript{40}

payment of royalties;\textsuperscript{41} and

payment of a bonus to Ghana.\textsuperscript{42}

The Act also prescribed specific terms that must be provided in the petroleum agreements. These include:

\begin{itemize}
  \item the right of GNPC to hold an initial participating carried interest of at least 15 per cent for exploration and development;
  \item the GNPC has the option to acquire an additional participating interest as determined in the petroleum agreement within a specified period of time;
  \item the petroleum agreement must be for a term not exceeding 25 years subject to ability of the Minister to extend;
  \item change of ownership of contracting party is subject to consent of the Minister or Commission; and
  \item the GNPC has the pre-emptive right to acquire interest of contractors.
\end{itemize}

The general requirements for petroleum activities under the Act include:

\begin{itemize}
  \item the standard of operations in conducting petroleum activities;\textsuperscript{43}
  \item supervision and inspection;\textsuperscript{44}
  \item data and information obtained by a licensee, contractor or subcontractor as a result of petroleum activities are property of Ghana;
  \item maintaining records of data and information in Ghana;
  \item provision of information upon request by the Minister;
  \item the use of Ghanaian goods and services;\textsuperscript{45} and
  \item the local content plan.\textsuperscript{46}
\end{itemize}

The Petroleum Commission Act, 2011 (Act 821)

As part of the regulatory reform following the commercial discovery of oil and gas, the Petroleum Commission was established under the Petroleum Commission Act as the upstream petroleum regulator with the object to ‘regulate and manage the utilisation of petroleum resources and to coordinate the policies in relation to them’.\textsuperscript{47} Essentially, the Act establishes the Petroleum Commission to perform the regulatory functions previously performed by the GNPC under the PNDCL 84.

\textsuperscript{40} Section 87 of Act 919.
\textsuperscript{41} Section 85 of Act 919.
\textsuperscript{42} Section 88 of Act 919.
\textsuperscript{43} Section 10(14) of Act 919.
\textsuperscript{44} Sections 50–55 of Act 919.
\textsuperscript{45} Section 71 of Act 919.
\textsuperscript{46} Section 63 of Act 919.
\textsuperscript{47} Section 2 of Act 919.
Petroleum (Local Content and Local Participation) Regulations, 2013 (LI 2204)
Pursuant to Act 821, the Petroleum (Local Content and Local Participation) Regulations
were passed in July 2013 to, among other things, ‘promote the use of local expertise, goods
and services, businesses and financing in the petroleum industry value chain and their
retention in the country’.48 The Regulations focus on ensuring the maximum participation of
indigenous Ghanaians, increasing local capacity and also safeguarding the interest of foreign
participants in the oil and gas sector.

The Regulations apply to contractors, subcontractors, service providers, licensees and
allied entities in the petroleum sector.49 The Regulations provide minimum thresholds for
indigenous equity participation in petroleum activities.50

A key provision under the Regulations is the requirement of 5 per cent indigenous
participation in petroleum agreements.51 This is, however, subject to negotiation and the
approval of the Minister. Service providers in the sector must have a minimum of 10 per cent
Ghanaian ownership.52 Other provisions include the requirement for the development and
approval of local content plans, which must at the minimum include sub-plans on employment
and training, research and development, technology transfer, legal and financial services.53 In
respect of legal services, operators are required to use the services of only Ghanaian lawyers
or law firms for legal services required in Ghana.54 The oil companies are required to submit
regular reports on their levels of compliance to the local content committee, which is set up
to oversee the implementation of the regulations and to ensure measurable and continuous
growth in local content in the petroleum sector.55

Petroleum (Exploration and Production) (General) Regulations, 2018 (LI 2359)
LI 2359 came into force in June 2018. The Regulations provide for the procedures and
conditions for the grant of a petroleum agreement including qualification requirements,
terms and conditions for open and competitive tendering procedures and direct negotiations.
The Regulations mandate the Minister acting in collaboration with the Commission as
well as other relevant agencies to prepare a strategic assessment plan for the opening up
of areas for petroleum activities.56 It also indicates that the initial participating interest of
the GNPC in relation to exploration and development shall be a carried interest, and in
the case of production operations, an additional participation interest.57 Other relevant
provisions include the procedure for licensing58 and the criteria for grant of licences,59 change
of ownership60 and operating standards under a petroleum agreement.61

48 Regulation 1 of LI 2204.
49 Regulation 3 of LI 2204.
50 Regulation 10 of LI 2204.
51 Regulation 4 of LI 2204.
52 Regulation 4(6) of LI 2204.
53 Regulation 7 of LI 2204.
54 Regulation 29 of LI 2204.
55 Regulation 5 of LI 2204.
56 Regulation 3 of 2359.
57 Regulation 34 of 2359.
58 Regulation 9 of 2359.
59 Regulation 51 of 2359.
60 Regulation 26 of 2359.
61 Regulation 66-70 of 2359.
The Petroleum Exploration and Production-Data Management Regulation, 2017 (LI 2257)

The Regulations apply to the reporting and management of petroleum data obtained from the conduct of petroleum activities within Ghana. This includes the receipt, interpretation and analysis of petroleum data, provision of a safe environment for storage of petroleum data submitted, efficient management of the data and the documentation and reporting for information related to acquisition and submission of petroleum data. The purpose of these Regulations is to specify the format, content and standards required for the preparation and submission of geological, geophysical and production data related to petroleum activities to support efficient exploration of petroleum resources in Ghana.62

The Petroleum (Exploration and Production) (Health, Safety and Environment) Regulations, 2017 (LI 2258)

LI 2258 applies to all petroleum operations. Among others, it aims to prevent the adverse effects of petroleum activities on health, safety and the environment and promotes high standards of health and safety. It provides the minimum health and safety requirements applicable to contractors, subcontractors and other players within the industry. The key regulations relate to design and operation of facilities, systems and equipment, maritime facilities, load-bearing structures, drilling and well systems, emissions and discharges, decommissioning, risk analysis and emergency preparedness and reporting.63

The Petroleum Revenue Management Act, 2011 (Act 815) as amended64

This Act was also enacted after the Jubilee Fields discovery to provide a regime for the collection, allocation and management of petroleum revenue in a transparent, accountable and sustainable manner for the benefit of the citizens of Ghana. The Act establishes a number of funds – the Petroleum Holding Fund,65 the Ghana Stabilisation Fund66 and the Ghana Heritage Fund67 – and indicates how revenues accruing from petroleum operations to the state are to be disbursed and utilised. All the funds created under the Act are public funds68 and may not be encumbered, used to provide credit or collateral for the state or private entities.69 The Act also prohibits borrowing against petroleum reserves.70

The Petroleum Revenue (Amendment) Act, 2015 (Act 839) was enacted to amend the Petroleum Revenue Management Act 2011. The amendment provides for the allocation of funds to the Ghana Infrastructure Investment Fund for the purposes of infrastructure development,71 the establishment of the Investment Advisory Committee72 and other related matters.

62 Regulation 1 of LI 2257.
63 ibid.
64 The Petroleum Revenue (Amendment) Act 2015 (Act 839).
65 Section 2 of Act 815.
66 Section 9 of Act 815.
67 Section 10 of Act 815.
68 Section 42 of Act 815.
69 Section 5 of Act 815.
70 ibid.
71 Section 11 of Act 815.
72 Section 10 of Act 815.
Petroleum (Exploration and Production) (Measurement) Regulations, 2016 (LI 2246)

LI 2246 came into force in November 2016 for the main purpose of ensuring that an accurate measurement and allocation of petroleum forms the basis for the determination of revenue that accrue to the parties to a petroleum agreement. It applies to the planning, design, testing, calibration, operation and maintenance of metering systems as well as equipment and methods for measuring the quantities of oil and gas produced, transported and sold. The Petroleum Commission is mandated under this regulation to supervise and inspect metering and allocation systems from the design to operation stage. These Regulations also permit an authorised agency to place a seal on export valves downstream of a metering station to prevent offloading of petroleum without authorisation.\(^73\)

Petroleum Commission Fees and Charges Regulations, 2015 (LI 2221)

These Regulations provide the framework for determining the applicable fees to be paid by participants in petroleum activities to the Petroleum Commission for various activities including permitting, third-party access over a facility that is owned by a contractor, registration of assignment of interest or transfer of shares, and registration of encumbrances over participating interest in petroleum agreements. Other costs include expenses and costs incurred by the Petroleum Commission in conducting its regulatory and supervisory services as well as fees for extension of exploration working periods and appraisal periods.\(^74\)

ii Regulation

Government of Ghana (through the Ministry of Energy)\(^75\)

The 1992 Constitution vests all petroleum resources in the president of Ghana as the head of the executive branch of government.\(^76\) The presidency expresses its ownership and control over oil and gas activities through the Ministry of Energy. The mandate of the Ministry of Energy includes the formulation, implementation and monitoring of national policies for the sector.\(^77\) The Ministry is the driver of government policy and has the overall responsibility to provide policy direction on oil and gas matters based on advice from the Petroleum Commission.\(^78\)

The Ministry receives applications from prospective contractors, negotiates terms of petroleum agreements and grants the right to explore, develop and produce oil and gas products. It is also responsible for granting consent for the transfer of petroleum rights and resolving disputes between the Petroleum Commission and contractors (prior to resorting to other dispute resolution options).\(^79\)

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\(^73\) Regulations 1, 2 and 4 of LI 2246.

\(^74\) Regulations 3 and 12–16 of LI 2246.

\(^75\) Formerly Ministry of Petroleum.

\(^76\) Article 257(6) of 1992 Constitution and Section 3 of Act 919.

\(^77\) https://www.energymin.gov.gh/about.

\(^78\) ibid; Section 94 of Act 919.

\(^79\) Sections 10 and 16 of Act 919.
**Parliament**

The 1992 Constitution requires all petroleum agreements to be ratified by Parliament.\(^{80}\) Parliament may also exempt particular transactions or agreements from ratification.\(^{81}\) These exemptions must be supported by the resolution of at least 75 per cent of the members of Parliament.\(^{82}\)

**Petroleum Commission**

As indicated above, the Petroleum Commission is established under Act 821 as an upstream petroleum regulator. The functions of the Petroleum Commission include:

\(a\) promoting planned, well-executed, sustainable and cost-efficient petroleum activities;

\(b\) recommending to the Minister national policies on petroleum activities;

\(c\) monitoring compliance with national policies, laws, regulations and agreements;

\(d\) complying with health, safety and environmental standards in petroleum activities;

\(e\) promoting local content and local participation in petroleum activities; and

\(f\) receiving applications and issuing permits for specific petroleum activities.\(^{83}\)

**Treaties**

Ghana became a signatory to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention) on 9 April 1968. It is also a signatory to the Convention on the Settlement of Investment Disputes between States and Nationals of Other States, which was ratified on 13 July 1966 and entered into force on 14 October 1966. Under the Alternative Dispute Resolution Act 2010 (Act 798), a foreign arbitral award is enforceable by the court if it is satisfied, inter alia, that the award was made under the New York Convention or other international convention ratified by Parliament.

In addition, the enforcement of foreign judgments in Ghana is based on the doctrine of reciprocity. On this basis, final judgments from Brazil, France, Israel, Italy, Japan, Lebanon, Senegal, Spain, the United Arab Emirates and the United Kingdom are enforceable in Ghana. For countries that do not have reciprocity, a fresh action must be instituted on the basis of the foreign judgement.

Further, Ghana has signed bilateral investment treaties (BITs) with over 25 countries; however, only eight of these BITs have been ratified. Countries with which Ghana has ratified BITs are China, Denmark, Germany, Malaysia, the Netherlands, Serbia, Switzerland and the United Kingdom.\(^{84}\)

In respect of taxation, Ghana has signed and ratified double taxation agreements with the Netherlands, Mauritius, Czech Republic, Switzerland, Belgium, Denmark, France, Germany, Italy, South Africa and the United Kingdom.\(^{85}\)

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\(^{80}\) Article 268 of 192 Constitution.

\(^{81}\) Article 268(2) of 1992 Constitution.

\(^{82}\) ibid.

\(^{83}\) Section 3 Act 821.


\(^{85}\) ibid.
III LICENSING

The E&P Act mandates the award of petroleum licences through competitive bidding and direct negotiations with potential investors. Hitherto, the majority of petroleum agreements were awarded by direct negotiations although there were few awarded through competitive processes developed by the Ministry of Energy, the GNPC and the Petroleum Commission. Under the current regulatory framework, there is strong emphasis on the award of petroleum agreements through competitive tendering although the Minister of Energy still has power to award blocks without a competitive tender albeit within defined circumstances and in a fair and transparent manner. The key processes for a licensing round by competitive tender include the following:

a publication of an invitation to tender or invitation for direct negotiations by the Minister of Energy; 87
b submission of expression of interest; 88
c formal invitation to tender; 89
d submission of bids; 90
e decision on bids; 91
f negotiations; 92 and
g entry into petroleum agreements. 93

An expression of interest among others shall include general corporate information of the interested person, the specific block of interested, a preliminary geological prospectivity of the area, financial and technical capabilities and the bidder's objective for engaging in petroleum activities in Ghana. The formal invitation to tender will state the nature of blocks on tender, the timeline for the tender process, applicable fees, information on access to data and bidding documents, etc. Bids submitted by interested investors must conform to the terms of the tender documents and will include notarised corporate documents of the bidder, nationality and corporate structure, areas of interest, the proposed work programme, fiscal terms, rate of return, carried interest for the state, local content levels, performance security and strategy to meet the policy objective of the bid round. Bids are evaluated on the basis of their responsiveness to the bid requirements and objective criteria prescribed by law, including rate of proposed royalty, bonus, knowledge transfer plan and health and safety. Bids are required to be opened publicly, and a list of participating bidders is to be published in the gazette, national newspapers and the website of the Ministry of Energy. Following the evaluations, all bidders will be notified of the outcome of the tender and the details of the winners formally published in the gazette, national newspapers and the website of the

86 Section 10(3) of Act 919.
87 Section 10(6) of Act 919.
88 Section 10(7) of Act 919.
89 Regulation 9(1) of LI 2359.
90 Ibid.
91 Ibid.
92 Section 10(12) of Act 919.
93 Regulation 9(1) of LI 2359.
94 Regulation 9(2) of LI 2359.
95 Regulation 12(1) of LI 2359.
96 Regulation 14(3) of LI 2359.
97 Regulation 16 of LI 2359.
Ministry of Energy. The preferred bidders are invited to negotiate the terms of the petroleum agreement. The Minister’s petroleum agreement negotiation team usually comprises senior officials from the Ministry of Energy, Petroleum Commission, the GNPC, the Attorney General’s Department, the Ghana Revenue Authority and other advisers and consultants as required. At the close of negotiations, the draft petroleum agreement is submitted to cabinet for approval and then to Parliament for ratification. A petroleum agreement is effective and enforceable only when parliamentary ratification is secured.

To complement awards by competitive tender, the Minister of Energy is also empowered to initiate direct negotiations with a qualified body corporate for a petroleum agreement without competitive tender. This option may be adopted where:

- only one interested investor expresses interest in a block after an invitation to tender;\(^\text{98}\)
- all or part of the area offered for tender in the competitive bidding process has not become the subject of a petroleum agreement but the Minister determines that it is in the public interest for that area to be subjected to a petroleum agreement;
- the Minister, in consultation with the Petroleum Commission, determines that direct negotiations represent the most efficient manner to achieve optimal exploration, development and production of petroleum resources in a defined area.\(^\text{99}\)

To facilitate negotiations towards the award of a petroleum licence, the Ministry of Energy has developed the Model Petroleum Agreement (MPA), which is regularly updated to reflect changes in existing legislation. The MPA is the basis of negotiating new Petroleum Agreements with prospective contractors. The key terms of the MPA include the following:

- incorporation of the contractor in Ghana;
- the area of activity;
- the exploration period of up to seven years;
- state benefits including carried and paid interest, additional oil entitlement, income tax, rental of government property and surface rent;
- contractor benefits, including the right to receive, remit, keep and utilise freely abroad all the foreign currency obtained from the sales of the petroleum; the right to request payment for sale of its oil entitlement in foreign currency;
- restrictions on assignment (subject to consent of the Minister);
- conditions for relinquishment;
- obligations of the contractor, including time for notification of discoveries, commencement of appraisal programmes and submission of development plans;
- establishment of a joint monitoring committee between the contractor and the Commission to review, approve, reject or request modifications of the work programme of the contractor, audit the cost of operations, procurement processes, employment contracts made by the investor;
- content of development plans including a plan for utilisation of associated gases;
- measurement and pricing of crude oil;
- conditions for use and flaring of natural gas;
- conditions for discovery and production of natural gas;

\(^{98}\) Section 10(8) of Act 919 where the Minister receives more than one expression of interest, a formal open transparent and competitive public tender process must be followed. Otherwise, the Minister may commence direct negotiations with the interested investor.

\(^{99}\) Sections 10(5) and (9) of Act 919.
environmental safety provisions including the regulator’s right to inspection and emergency reporting;

- title to equipment;

- relinquishment and decommissioning;

- local content (procurement of goods and services, contribution to training); and

- dispute resolution (mandatory 30-day period for consultation and negotiation, arbitration under the Arbitration Institute of the Stockholm Chamber of Commerce, Stockholm, Sweden).

The term granted under a petroleum agreement is not to exceed 25 years and may be terminated ahead of term in accordance with the terms of the petroleum agreement. The conditions for early termination include:

- relinquishment and surrender of the entire contract area;

- failure to give notification of a discovery after the maximum exploratory period;

- contractor’s failure to commence operations within the time limit for commencement;

- submission of false information to the Petroleum Commission;

- assignment of rights without the consent of the Minister;

- insolvency or bankruptcy of the contractor; and

- material breach of the contractor’s obligations.

IV PRODUCTION RESTRICTIONS

The total production of oil and gas is shared among the parties in accordance with the petroleum agreement under which the operations are made. Once the compulsory provisions of the E&P Act on the various payments to be made and interest due to the GNPC have been met, there are no restrictions on the distribution of production.

A contractor is entitled to export all its crude oil entitlements under a petroleum agreement. However, where there is an emergency affecting the local supply of crude oil, a contractor may be required by the Minister to sell all or part of its entitlement to the government. This provision has been translated into the MPA, which imposes an obligation on the contractor to support the domestic supply to ensure that crude oil available to the GNPC and the government is sufficient to meet the domestic requirements. Crude oil supplied to meet this requirement shall be priced at the weighted average of the world market prices of comparable crude oils sold at arm’s-length transactions for the month of delivery and adjusted for quality, location, etc., and expressed in US dollars.

Under the MPA, the price of crude oil delivered is determined by whether or not it is sold or otherwise disposed of in an arm’s-length transaction. Where the transaction is conducted at arm’s length, the price shall be the amount actually realised by the contractor. Otherwise, the price shall be determined by reference to world market prices of comparable crude oil sold in arm’s-length transactions for export in the major world petroleum markets, and adjusted for oil quality, location and conditions of pricing, delivery and payment.
V ASSIGNMENTS OF INTERESTS

The E&P Act prohibits the direct or indirect transfer of interests in petroleum agreements (in whole or in part) to third parties without the prior written consent of the Minister.\(^\text{100}\) This restriction applies to both contractors and subcontractors.\(^\text{101}\) The Act also prohibits the transfer of 5 per cent or more of the shares in a contractor or subcontractor’s company to a third party without the consent of the Minister and Petroleum Commission respectively.\(^\text{102}\) The Minister may impose conditions for approval of the assignment.\(^\text{103}\) This provision is further reflected in the MPA, which goes further to add that consent shall not be unreasonably withheld or delayed and may be given subject to conditions deemed appropriate by the Minister or the Petroleum Commission. At all times, the GNPC has the first right of refusal where a contractor intends to dispose of its interest in a petroleum agreement.\(^\text{104}\)

VI TAX

Taxation of activities in the upstream oil and gas sector is regulated under the Petroleum Income Tax Act 1987 (PNDCL 188), and the Income Tax Act, 2015 (Act 896) as amended. Corporate income tax is assessed at 35 per cent of the chargeable income or as provided in the taxpayer’s petroleum agreement.\(^\text{105}\) The prevailing rate in recent petroleum agreements is 35 per cent.

Corporate income tax is calculated net of all expenses that are incurred in the petroleum operations and approved by the Petroleum Commission and the GRA as petroleum costs.\(^\text{106}\) The allowable deductions include rental fees, royalties, interest on fees and loans, expense on maintenance, repair or alteration of machinery, debts directly incurred in the conduct of petroleum operations, contributions to pension or provident funds approved by the Petroleum Commission, capital allowance (determined by the law) and losses from the previous year of assessment.\(^\text{107}\) Expenses that are not allowed are stated under the Act;\(^\text{108}\) these include research and development expenditure, bonus payments made in respect of the grant of the petroleum licence and expenditure incurred as a consequence of a breach of a petroleum agreement.

Employees of petroleum operators are subject to personal income tax at varying rates depending on their nationality and income.\(^\text{109}\) Petroleum agreements may provide some exemptions for foreign employees working in Ghana for periods under 30 days.\(^\text{110}\) Other taxes that are typically exempted under petroleum agreements are value added tax (VAT),

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100 Section 16 of Act 919.
101 ibid.
102 Sections 15 and 17 of Act 919.
103 Regulation 27(3) of LI 2359.
104 Section 18 of Act 919.
105 Section 5 of the First Schedule to Act 896.
106 Section 67(1) of Act 919.
107 ibid.
108 Section 67(2) of Act 919.
109 Section 63 and First Schedule to Act 896.
110 Article 12.8 of the MPA.
customs and import duties and taxes associated with importation of equipment for petroleum operations. It should be noted that these tax exemptions are subject to parliamentary approval as provided under the Constitution.111

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The E&P Act and the MPA require strict compliance with the Environmental Protection Agency Act 1994 (Act 490), the Environmental Assessment Regulation 1999 (LI 1652) and best environmental practices in the international oil and gas industry.

i E & P Act

This Act requires a licensee or contractor that operates a petroleum facility to submit a decommissioning plan to the Minister for approval not more than five years and not less than two years before the date on which the petroleum facility is to permanently cease operation or before the expiration of the licence or relevant petroleum agreement.112 The Act also requires a licensee or contractor to establish a decommissioning fund as prescribed.113 In the event of abandonment of a well, the contractor is required to submit an immediate notice of intention to abandon the well to the Commission.114 Thereafter, the contractor must treat and plug the abandoned well with the prior written approval of the Commission and in a manner consistent with international best practices and as approved by the Commission.115 A contractor or licensee who is under an obligation to implement an approved decommissioning plan is strictly liable for any loss or damage caused in connection with the decommissioning of the facility or the implementation of the decommissioning plan.116

ii Environmental Protection Agency (EPA) Act 1994 (Act 490)

This Act grants the EPA the mandate to formulate policy on the environment, prescribe standards and guidelines and issue environmental permits and pollution abatement notices. The Act also empowers the EPA to request an environmental impact assessment (EIA) prior to the grant of permits for any activity that may adversely affect the environment, which includes exploration, development and production of oil and gas.117

112 Section 43 of Act 919.
113 Section 45 of Act 919.
114 Section 46 of Act 919.
115 ibid.
116 Section 48 of Act 919.
117 Section 12 of Act 490.

Under Act 490, all activities that have the potential to adversely affect the environment must be subjected to environmental assessments. These regulations provide the requirement for all the different assessments to be undertaken. These include the following:

- preliminary environmental assessments;
- EIAs;
- environmental impact statements;
- environmental management plans;
- environmental certificates; and
- environmental permitting.

In addition to the LI 1652, the EPA has issued several guidelines to regulate the EIA process. The key guidelines relating to oil and gas activities are the EPA Guidelines for Environmental Assessment and Management in the Offshore Oil and Gas Development (2010), the Dispersant Importation and Use Guidelines and the Oil Waste Management Guidelines and the Dispersant Policy. These guidelines require preliminary environmental assessments for small to medium-impact scale undertakings and EIAs for field development and production activities.

The E&P Act, requires the GNPC and contractors to restore affected areas and to remove items with the potential to damage the environment at the end of the petroleum operation. The activities required to be undertaken include plugging abandoned wells. Contractors are required to submit detailed decommissioning plans as part of a development plan for approval. Under the petroleum agreements, the obligation for decommissioning is placed on the contractor who must submit annual reports to the EPA for reviews and monitoring. Contractors are also required to create a decommissioning fund as prescribed in the development plans to finance the decommissioning process during the life of the oil field.

iv The role of the Ghana Maritime Authority

The Ghana Maritime Authority (GMA) was established under the Ghana Maritime Authority Act, 2002 (630). It is the core government agency charged with the responsibility of monitoring, regulating and coordinating activities in Ghanaian waters and in the maritime industry. The GMA is responsible for ensuring a safe and secure marine environment and in charge of monitoring economic activities in Ghanaian waters including oil and gas activities. To ensure the safety and protection of vessels, infrastructure and other assets within Ghana’s maritime jurisdiction, the GMA is mandated under the Ghana Shipping (Protection of Offshore Operations and Assets) Regulations, 2012 (LI 2010) to issue permits for operation,

118 ibid.
119 Regulation 3 of LI 1652.
120 ibid.
121 Regulation 9 of LI 1652.
122 Regulation 15 of LI 1652.
123 Regulation 10 of LI 1652.
124 Regulation 4 of LI 1652.
125 Section 47 of Act 919.
126 Section 46 of Act 919.
127 Section 43 of Act 919.
128 Section 45 of Act 919.
129 Section 2 of Act 630.
location and movement of mobile offshore drilling equipment.\(^{130}\) Other activities that require a GMA permit are the operation of vessels, siting of installations and storage facilities and the laying of pipes, cables, equipment and all structures and devices on the seabed or in an area within Ghana’s maritime jurisdiction.\(^{131}\)

The GMA is also the implementing agency of Ghana’s obligations as a member of the International Maritime Organization (IMO).\(^{132}\) Accordingly, it is responsible for ensuring compliance with the design, construction and equipment requirements of the Code for the Construction and Equipment of Mobile Offshore Drilling Units, 1979 (IMO Resolution A.414 (XI) as amended by MSC/Circ. 561); (the 1979 Mobile Offshore Drilling Unit Code) and has in force a Mobile Offshore Drilling Unit Certificate (1979); or the Code for the Construction and Equipment of Mobile Offshore Drilling Units, 1989 (IMO Resolution A.649 (16) as amended by MSC/Circ. 561 and Resolution MSC.38 (63); (the 1989 Mobile Offshore Drilling Unit Code) and has in force a mobile offshore drilling unit certificate (1989).\(^{133}\)

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Under the E&P Act, a contractor in a petroleum agreement is required to be incorporated in Ghana.\(^{134}\) Therefore, a foreign investor must incorporate a local entity in Ghana to enter into a petroleum agreement. The entity is also required to open a bank account and maintain an office in Ghana with a representative who has the authority to bind the contractor.\(^{135}\) A branch of a foreign entity cannot be a party to a petroleum agreement.\(^{136}\) Subject to providing all the relevant documentation, a local entity may be incorporated within 10 working days. The entities with foreign ownership are required to register with the Ghana Investment Promotion Centre prior to commencement of operations.\(^{137}\)

ii Capital, labour and content restrictions

As discussed above, the Petroleum (Local Content and Local Participation) Regulations (LI 2204) regulates local content in the upstream sector. Significant provisions include the following requirements:

- a minimum of 5 per cent indigenous participation (other than GNPC) in petroleum agreements;\(^{138}\)
- b minimum of 10 per cent Ghanaian ownership in service providers to be increased to 50 per cent in five years and 60–90 per cent after 10 years;\(^{139}\)

\(^{130}\) Regulation 8 of LI 2010.
\(^{131}\) Regulation 10 of LI 2010.
\(^{132}\) https://www.ghanamaritime.org/welcome.php; Section 2 of ACT 630 as amended.
\(^{133}\) https://www.ghanamaritime.org/welcome.php.
\(^{134}\) Section 70 Act 919.
\(^{135}\) ibid.
\(^{136}\) ibid.
\(^{137}\) Section 24 of GIPC Act (Act 865).
\(^{138}\) Regulation 4(2) of LI 2204.
\(^{139}\) Part 1 of the First Schedule to LI 2204.
minimum targets for areas such as front-end engineering design (FEED), fabrication and construction, materials and procurement, well drilling services, marine operations and logistics services and transportation, supply and disposal services; 

submission of a local content plan showing how priority will be given to local goods and services and use of local professionals and a training plan;

an employment and training sub-plan;

a research and development sub-plan;

a technology transfer sub-plan;

a legal services sub-plan, and

a financial services sub-plan.

LI 2204 places an obligation on contractors to hire more Ghanaians over time and develop plans for attaining almost 100 per cent indigenous employment within 10 years of starting petroleum operations. The employment of staff (Ghanaians and expatriates) in the oil and gas sector is also regulated under the Labour Act and the Pensions Act.

iii Anti-corruption

Since assuming its regulatory role in 2011, the Petroleum Commission prioritised the need to improve the public perception about the upstream sector by increasing consultation and transparency in the sector. In its regulatory role, the Commission monitors compliance with national law on anti-corruption and bribery. Foreign entities are also monitored by other public agencies for compliance with foreign anti-corruption legislation that have extraterritorial effect such as the Foreign Corrupt Practices Act of the US and Bribery Act of the UK.

Until recently, a key concern was transparency in the process of the award of petroleum rights. To resolve this, the E&P Act and the recently passed LI 2359 provide mandatory rules on competitive tendering and direct negotiations to ensure that all future petroleum rights are awarded in a fair, open and transparent manner. As already discussed above, these tendering processes were followed by the government in the recent licensing round. The E&P Act also provides for the establishment of a public register of all petroleum agreements, which has been set up by the Petroleum Commission. Also, the variation of terms in the various petroleum agreements have raised concerns relating to fairness and transparency.

The introduction of an anti-corruption warranty clause in recently negotiated petroleum agreements is expected to pave the way for even further reforms in transparency in the grant of petroleum rights. The clause requires contracting parties to certify compliance with the anti-corruption laws of Ghana, their countries of incorporation as well as the Convention

140 Part 2 of the First Schedule to LI 2204.
141 Regulation 7 of LI 2204.
142 Regulation 17 of LI 2204.
143 Regulation 21 of LI 2204.
144 Regulation 24 of LI 2204.
145 Regulation 30 of LI 2204.
146 Regulation 32 of LI 2204.
147 Part 1 of the First Schedule to LI 2204.

IX CURRENT DEVELOPMENTS

i Hess–Aker Energy Acquisition

On 1 June 2018, Aker Energy announced the acquisition by its subsidiary Aker Energy Ghana AS, of Hess Ghana, the operator of the Deepwater Tano Cape Three Points block (DWT/CTP), which holds an estimated 550 million barrels of oil and has the potential for a further 400 million barrels. Following the acquisition, Aker Energy is currently the operator of the DWT/CTP block and the holder of a 50 per cent interest with the other partners Lukoil (38 per cent), Fuel Trade (2 per cent) and GNPC (10 per cent). Aker Energy has also announced that the licence partners intend to submit a plan of development in the first half of 2019 with anticipated first oil in the fourth quarter of 2021.

ii Amendment of the South Deep Water Tano Petroleum Agreement

In 2018, TRG, a company owned by Kjell Inge Røkke, the principal shareholder of Aker acquired an interest in the South Deepwater Tano block (SDWT). Through its investment in Petrica Holding, TRG acquired all the issued shares of AGM Petroleum Ghana Ltd from AGM Gibraltar. Following a recent ratification of the amendment of the petroleum agreement for the SDWT block, the participating interest in the block is currently held by the GNPC (15 per cent), AGM Petroleum (85 per cent, 5 per cent of this 85 per cent is planned to be transferred to a Ghanaian partner).

iii Recent licensing rounds

As already discussed above, the government in 2018 announced plans to award licences for nine new oil blocks in the Western Basin. Six of the blocks were planned to be allocated through open public competitive tender, two through direct negotiations and one shall be reserved for the GNPC to explore in partnership with its chosen strategic partner. The government commenced the competitive bidding process for three blocks and received a total of 60 applications from prospective investors. In June 2019, the government announced First E&P Ltd/Elandel Energy Ghana Ltd and Eni/Vitol as the successful bidders for two blocks. This is a significant development in the sector as it is the first competitive bidding process for oil blocks in Ghana. While some regard it as a success, the withdrawal of some major IOCs from the final bid has led to some speculation. However, the exact reasons for their withdrawal has not been made public by the IOCs.

In January 2018, the government signed a petroleum agreement with ExxonMobil in respect of the Deepwater Cape Three Points block. ExxonMobil holds an 80 per cent interest in the licence and will act as operator of the block. The other licence partners are GNPC (15 per cent). Five per cent interest is expected to be granted to a Ghanaian company to be identified by ExxonMobil and the government.
iii Developments in Gas

On 4 July 2018, ENI, the operator of the OCTP Integrated Oil and Gas Development Project announced the start of gas production from two of the four deep-water subsea wells connected to the FPSO John Agyekum Kufuor in the Sankofa field. OCTP is planned to deliver 180 million standard cubic feet per day for at least 15 years. Natural gas production will flow through a dedicated 60km pipeline to an onshore receiving facility in Sanzule.

The GNPC has recently announced the completion of the initial phase of the TTIP, the Takoradi–Tema Interconnection Project otherwise known as the West African Gas Pipeline reverse-flow project (the Project). Ghana’s TTIP has been linked to the offshore West African Gas Pipeline (WAGP), which transmits gas west from Nigeria to customers in Benin, Togo and Ghana. The Project aims to reverse-flow gas from the Western Region of Ghana to the Tema power enclave. The successful execution of this scope of the Project paves the way for the smooth flow of gas from the Western Region of Ghana to Tema in the Greater Accra Region for use by the various gas offtakers in the Tema-Accra power and industrial enclave. The TTIP will initially be able to transport a maximum of 1.7 million cubic metres per day east from Ghana’s Aboadze terminal to power plants at Tema.

The next phase of the Project which includes the revamping of the WAPCo Tema Regulatory and Metering Station (RMS) is ongoing and is expected to be completed by the fourth quarter of 2019. The successful completion of the Project has enormous benefits for Ghana’s power sector. According to the CEO of GNPC, GGCL’s ability to supply gas for a stable production of electricity means that, the cost of electricity to the final consumer will now be relatively lower as compared to the use of heavy fuel oil or diesel as fuel for electricity generation. Also, the cost of production for local companies, especially in the manufacturing and mining sectors, will reduce significantly to enable them become more competitive. The Project has also doubled the capacity of GGCL to transport the GNPC’s gas to feed critical national power generation facilities sited in the western enclave. Again, gas users in the Accra–Tema region are assured of relatively more reliable gas supply through the TTIP.

vi Onshore exploration activities

Following the award of the licence for the Onshore/Offshore Keta Delta Block to GNPC, Swiss African Oil Company and PET Volta Investments in 2016, the operator of the block, Swiss African Oil Company (a subsidiary of Swiss African Petroleum Ag) has commenced a public hearing as part of the processes for an environmental impact assessment for the project. The public consultations are expected to help elicit concerns and expectations from communities about a proposed 2D seismic survey by operator in the Keta Delta Block. The Keta Basin covers an area of approximately 33,900km² of which 1,900km² is onshore.

150 https://www.gnpcghana.com/news71.html#.
GREENLAND

Michael Meyer

I INTRODUCTION

Greenland, the world’s largest island, is one of the areas in the world where oil and gas resources have been least explored. This is largely owing to the extreme natural conditions, remote location, sensitivity towards environmental issues and hence high exploration costs.

Greenland is a semi-independent part of Denmark. It became an integral part of the Danish Realm in 1953. It joined the European Community (now the EU) with Denmark in 1973, but withdrew in 1985. Greenland was, following a referendum, granted self-government (home-rule) in 1979 by the Danish parliament. In 2008, another referendum regarding Greenland’s autonomy was held. Based on the results of the referendum (although non-binding) and the adoption of the Greenland Self-Government Act, Greenland has had self-government from 21 June 2009. Although Denmark exercises control over several policy areas on behalf of Greenland, including foreign affairs, security and financial policy (in consultation with Greenland’s self-rule government), Greenland itself owns and has disposal rights over oil and gas resources in Greenland.

Greenland has considerable potential hydrocarbon resources and a supportive political and legal framework; however, Greenland continues to struggle to sustain a thriving oil and gas industry. Despite several exploration licences having been issued, there is currently no active oil or gas production in Greenland.

Oil and gas licensing in Greenland started in the early 2000s, with licensing rounds in 2002, 2004, 2006, 2010 and 2012–13. In addition, Greenland has offered separate open-door procedures in the Jameson Land, South West Greenland and most recently the Disko-Nuussuaq area, which was open for applications until 31 December 2018. Additionally, one licensing round was conducted for the Davis Strait until late December 2018, while a licensing round for Baffin Bay ended in December 2017. At the time of writing, no information about licences granted in the latest licensing rounds or any plans for additional licensing rounds was available.

Exclusive exploration and exploitation licences for hydrocarbons have been issued to various international oil companies. Each licence is issued for a defined geographical area and time period. Licensees include Capricorn Greenland Exploration, PA Resources, ConocoPhillips Global, Maersk Oil Kalaallit Nunaat, Shell Greenland, ENI Denmark, Statoil Greenland, Chevron, BP Exploration Operating Company, DONG E&P Gronland and Greenland Gas and Oil. However, during past years, several of the major players have surrendered some or all of their licences.

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1 Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleague, assistant attorney Hans Nikolaj Amsinck Boie, for his assistance with this chapter.

2 Act No. 473 of 12 June 2009 on Greenland’s Self-Government.
Certain non-exclusive prospecting licences have also been issued. Licensees include TGS-NOPEC Geophysical Company, Statoil Greenland, GX Technology, Capricorn Greenland Exploration, ConocoPhilips, Norwegian University of Science and Technology, EMGS, Shell Greenland, DONG E&P Grønland, GDF Suez and Cambridge Arctic Shelf Programme.

As is evident, various international oil companies from Europe and North America have been granted oil and gas licences in Greenland. With the declining investigation activities in the global oil and gas industry and the past years’ dramatic fluctuations and decrease in oil prices, fewer deposits of hydrocarbons may be found commercially attractive, consequently affecting Greenland’s economic situation and future economic self-reliance.

II LEGAL AND REGULATORY FRAMEWORK

Greenland exercises its own control over licensing for oil and gas exploration and production, under the authority of the Ministry of Mineral Resources.

i Domestic oil and gas legislation

The origin of Greenland’s regulation of natural resources, including oil and gas, is the Danish Subsoil Act and the current regulation is found in the Mineral Resources Act (the Act) entering into force on 1 January 2010. Subsequent changes regarding, for example, the relevant authorities, appeals and the transfer of certain rights and obligations to the government of Greenland entered into force on 1 January 2013 with additional changes to obligations regarding public hearings of environmental impact assessments (EIA) and social sustainability assessments (SSA) entering into force on 1 July 2014. Most recently, the Act was amended in the autumn of 2018.4

The Act transfers the former joint Greenlandic and Danish responsibility for the natural resources in Greenland to the sole responsibility of Greenland. The Act is a framework act laying down the main principles of the administration of the mineral resources and subsoil activities. Within this framework, Greenland’s government is entitled to lay down specific provisions in, for example, model licences.

ii Regulation

The general authority for hydrocarbons is the Ministry of Mineral Resources and Labour (MMRL), including the responsibility for social aspects (e.g., SIA). Environmental aspects are handled by the Environmental Agency for Mineral Resources Activities (EAMRA) under the Ministry of Environment and Nature, and the day-to-day aspects of the industry as well as licence applications are handled by the Mineral Licence and Safety Authority (MLSA). In general, licences for hydrocarbons are granted by the government.5

The aim of the Act, and as such the responsibility of the government and of the established authorities is to ensure that performance of activities required under the Act

3 Inatsisartut Act No. 7 of 7 December 2009 with subsequent amendments.
4 Inatsisartut Act No. 16 of 27 November 2018. The amendment entered into force on 1 January 2019 and concerned changes for reasons of consistency following the introduction of new legislation on hydro power and on municipal administration.
5 For more information, see www.govmin.gl.
are carried out in accordance with acknowledged best international practices under similar conditions. Complaints about decisions made by the MLSA or the EAMRA may be brought before the government within a six-week time limit from the date of notification.

iii Treaties

In 1972, Denmark acceded to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards. It was confirmed that the Convention would apply to Greenland as of 10 February 1976. Further, judicial decisions enforceable in Denmark, based on, for example, conventions to which Denmark is a party, are also recognised as enforceable by the courts in Greenland.

There are no significant trade or bilateral investment treaties entered into by Greenland, however, Greenland is a member of the World Trade Organization and its rules apply to Greenland.

Greenland has entered into double taxation agreements with Denmark, the Faroe Islands, Iceland and Norway.

Further, bilateral agreements on the exchange of information have been made between Greenland and several other countries.

III LICENSING

An overview of the licensing possibilities for hydrocarbons (oil and gas) is set out below.

The licensing generally takes place on standard 'model terms'. These terms may be amended according to the requirements for the licence in question.

Hence, the focus here is on the requirements set out in the Act as these requirements establish the framework for the terms of the licences issued. In general, any interested party may apply for a licence for prospecting, exploration or exploitation within a specific geographical area. During the application process for exploration or exploitation, the MLSA will, in particular, attach importance to the technical and financial capabilities of the applicant as well as how the applicant intends to carry out the exploration or exploitation or both, as set out in more detail below.

i Hydrocarbons

A licence for hydrocarbons may be obtained through one of the following procedures:

a an open-door procedure by which a certain geographical area, within a specified period of time as determined by the Greenlandic self-government, is open for applications for licences;

b a licensing round whereby the Greenlandic self-government offers a specified geographical area for licensing based on specific licensing terms;

c a ‘specific licensing round’ if an application for a licence for an area has been handed in outside of a licensing round and the government is of the opinion that the application should be considered; and

d a ‘neighbouring procedure’ whereby a licensee based on geological or exploitation considerations is granted a licence to an adjoining geographical area.

Regardless of the specific procedure of licensing, any licence for prospecting, exploration or exploitation of hydrocarbons is granted through an application process operated by the MLSA. Any licence will be granted in accordance with the Act and will be based on the terms
and conditions published in connection with the licence procedure in question. Any licence will be subject to the payment of fees and charges stated in the licensing documentation. Certain fees and charges may be changed during the term of the licence.

Irrespective of the procedure used, a prospecting licence may be granted for a period of up to five years with the possibility of extensions. A prospecting licence is non-exclusive, and, therefore, several different licences for prospecting may cover the same geographical area.

In respect of licences for exploration, such licences are usually granted for up to 10 years with the possibility of extensions of up to three years at a time. Licences for exploration are normally exclusive for the area covered by the licence. In general, the terms of an exploration licence will set out the obligations on the licensee to explore the area as well as obligations in respect of areas that must be relinquished during the term of the licence.

A licensee holding a licence for exploration of a specific geographical area has a right to obtain a licence for exploitation in such area provided that the licence terms of the exploration licence have been fulfilled.

Licences for exploitation are normally granted for a period of 30 years. A ‘stand-alone’ exploitation licence may be granted for a period of up to 10 years with the possibility of multiple extensions; each extension may be granted for a period of up to three years.

The aggregate period of (extended) exploitation licences may not exceed 50 years.

ii Restrictions on foreign participation, capital requirements and legal immunity

Any licence for exploitation of hydrocarbons may only be granted to a public limited company domiciled in Greenland (see below). Such licensed company may only carry out the activities set out in the licence and may not be subjected to joint taxation, unless joint taxation is mandatory. Furthermore, licensed companies must trade on arm’s-length terms and not be more thinly capitalised than the rest of the group of companies to which the company holding the licence belongs. However, the licensed company’s loan capital may exceed the shareholders’ equity by up to a ratio of 2:1.

Any licence issued under the Act enjoys immunity from legal prosecution.

iii General requirements for licensees

Licences under the Act will generally include: (1) terms on the fees and charges payable to the Greenland self-government during the licence period; (2) that a company fully owned by the Greenland self-government is entitled to join in the licence on specified terms; (3) that the licensee to a certain extent may be required to employ local labour (see below); (4) that the licensee may be obligated to process exploited minerals in Greenland; and (5) that a licensee may be required to conduct surveys and prepare and implement plans to ensure that exploration and exploitation of the mineral resources in question are socially and environmentally sustainable.

A prospective licensee for hydrocarbons under the Act is subject to a number of more or less strict criteria.

Particular importance is attached to the technical capabilities of any potential licensee for exploration or exploitation licences – in short, the MLSA considers the expert knowledge of the applicants, their previous experience in exploration or exploitation of hydrocarbons (in general) and their previous experience in exploration or exploitation of hydrocarbons in places with conditions comparable to those of Greenland.

An exploration or exploitation licence will usually place an obligation on the licensee to make very substantial investments prior to the commencement of any commercial activities.
Additionally, there are specific requirements regarding the capital or financing of the licensee that must be upheld as set out above. Hence, the financial capability of any potential licensee of hydrocarbons is closely considered. The MLSA generally requires a full parent guarantee as well as an insurance policy to cover any liability arising under the licence applied for. Any licensee of offshore activities must be a member of the Offshore Pollution Liability Association Ltd (OPOL).

The fees for the submission of an application under the 2018 licensing round are 50,000 Danish kroner and 200,000 kroner for the granting of an exploration and exploitation licence or for the extension for exploration purposes. The annual fee for an exploitation licence is 1 million kroner. Further, the licensee must reimburse the MLSA for all costs and expenses incurred in the processing of the application. Additional amounts based on royalties and drilling commitments, etc., will also be payable.

iv Specific technical and financial selection criteria
In the selection of licensees for exploration and exploitation licences, particular importance is attached to the technical and financial capabilities of the applicant, as well as the relevant authorities’ assessment of the applicant’s former activities in Greenland (if any). If there is more than one applicant for a specific geographic area, particular importance will be attached to the date of the application, the applicant’s previous experience from activities in Greenland and possible previous fieldwork carried out by the applicant in the licence's geographic area. Additionally, the applicant’s offer to provide training and employment to Greenlandic labour for fieldwork regarding the specific exploration project is considered.

Further, an applicant’s past lack of efficiency or instances of non-performance of obligations under previous licences will also be taken into consideration by the MLSA in the assessment. Additionally, other relevant, objective and non-discriminatory criteria may be taken into consideration in order to select among equally qualified applicants.

IV PRODUCTION RESTRICTIONS
Under the Act and the standard terms for hydrocarbon prospecting licences (issued March 2009), there are no restrictions on production entitlements, no restrictions on exports of oil and gas, no requirements for sales of production into the local markets and no laws applicable to price setting related to oil or gas. This does not, however, preclude the government from applying these or similar production restrictions in the granting of a licence on a case-by-case basis.

V ASSIGNMENTS OF INTERESTS
Under the standard terms for hydrocarbon prospecting licences (issued March 2009), a licence or any part thereof cannot be directly or indirectly transferred to any other party unless the transfer is approved by the government, in accordance with the Act. A similar wording was included in the model licence for the 2018 licensing round. There are no express statutory rights of first refusal or preferential purchase rights upon transfer. A fee is payable on approval of any transfer.
VI TAX

The tax authorities of Greenland consist of two administrative bodies: the Tax Administration and the National Tax Board.

The Greenlandic tax system is quite simple compared to most other developed countries, with only a few tax and fiscal Acts.

Companies pay corporate income tax. Companies subject to the Mineral Resources Act may apply for a partial exemption reducing the corporate income tax rate, insofar as this exception follows from the mineral resources licence.

Resident companies are subject to tax on their global income. A company is deemed resident if it is incorporated in Greenland. The general tax rate for companies is 30 per cent and a potential surcharge tax of 8 per cent of the tax paid for the 2018 income year. Accordingly, the total effective tax rate is 31.8 per cent for the income year 2018.

There is no specific mineral resources tax act. Accordingly, taxes are payable in accordance with the ordinary tax legislation, namely the Act on Income Taxes. However, companies operating under the Mineral Resources Act (licensees) may apply for an exemption of the surcharge, thereby lowering the effective corporate tax rate from 31.8 per cent to 30 per cent for the income year 2018. Further, licensees must pay certain fees and surplus royalties to the government pursuant to the Mineral Resources Act.

A licence to mineral resources may include provisions for the payment of an annual fee calculated on the basis of the size of the area covered by the licence (land fee). Further, conditions on payment of a fee calculated on the basis of extracted raw materials, etc. (production fee), or conditions on payment to Greenland of a share of the profits from the activities under the licence (dividend fee) may apply. The fee provisions are set out in the licences.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The Act contains elaborate provisions on the protection of the environment. The provisions aim to prevent, limit and control pollution of and other impact on nature and the environment due to activities carried out pursuant to the Act. It is a general prerequisite that any activities to be carried out under the Act that may result in pollution must be carried out in a place where the danger of pollution is limited to the extent possible. Further, any licensee meeting the obligations under a licence must ensure and promote the use of the best available techniques, including the least-polluting facilities, machinery, equipment, processes, technologies, raw materials, substances and materials and the best possible measures for the reduction of pollution insofar as this is technically, practically and financially feasible.

As regards the more general protection of the environment, the Act sets out that if an activity or a facility is presumed to have a significant negative impact on the environment, a licence or an approval may only be granted on the basis of an assessment of the impact of the activity or facility on the environment and after the public and the authorities, etc., being affected have had an opportunity to express their opinion.

This requires that an environmental impact assessment (EIA) is carried out prior to, for example, exploitation of hydrocarbons. The EIA must be carried out and paid for by the applicant according to the guidelines issued by the authorities. Additionally, the authorities may require that a social impact assessment (SIA) is carried out in the event that an activity under the Act is assumed to have a significant impact on social conditions. This assessment must also be carried out at the cost of the applicant and in accordance with the guidelines set out by the authorities. The authority responsible for the SIA is the MMRL.
Environmental damage is defined as: (1) the pollution of the soil, the sea, the sea floor, the subsoil, water or air; (2) pollution of or other negative impact on the climate; (3) pollution of or other significant negative impact on nature, including human beings, fauna or flora; and (4) significant disturbance of nature, including human beings, fauna or flora owing to noise, vibrations, heat, light, etc. The party responsible for environmental damage is stated as the party performing, being in charge of or supervising the performance of an activity under the Act. In this respect note that if the party concerned is a party other than a licensee of the licence relating to the activity, the licensee is jointly and severally liable and responsible for the activity in question.

Based on the licence’s strict liability for (also) environmental damage the licensee must pay compensation for such damage. Hence, compensation must be paid for personal injury and loss of dependency; damage to property; other financial losses; reasonable costs of measures to prevent and mitigate pollution and any other negative impact on the environment, climate and nature. The same applies to the restoration of the environment and nature. The amount of compensation payable may under certain circumstances be reduced to a lower amount than the actual amount of damage.

There is special regulation of offshore facilities. The authorities may set out regulations to mitigate the health and safety risks on offshore facilities and it is the obligation of the licensee to identify, assess and reduce the risks to the extent possible. The authorities will set up an emergency committee with the task of coordinating the actions of the authorities in the event of accidents or emergencies.

Any licence granted under the Act sets out the obligations of the licensee regarding clean-up and demolition of plants and other facilities established by the licensee as well as the monitoring by the authorities of such activities.

Any application for exploitation must set out a detailed plan with the steps to be taken upon cessation of exploitation activities regarding the plants and other facilities established by the licensee and how the area in question will be left (closure plan). In the event that the licensee intends to leave behind certain facilities that, owing to environmental, health or safety reasons will require maintenance or other measures, the closure plan must include such maintenance and other measures as well as the monitoring thereof. Further, the closure plan must set out how it will be implemented financially. The closure plan must be approved prior to any exploitation activities being commenced, and the approval may include the provision of measures regarding environmental protection, health and safety. The licensee may be obliged to provide (financial) security to ensure the fulfilment of the closure plan.

Any suspension of exploitation activities requires prior approval to ensure that the facilities are adequately maintained and monitored during the suspension. Any closure plan must at all times be kept up to date considering the current exploitation activities of the licensee. The licensee must accept that the closure plan, including the financial security provided during the term of the exploitation licence, may require amendment by the authorities owing to developments in the exploitation activities and the general development of society or both.

Licensees are subject to strict liability for any acts or omissions under the licence causing damage. However, the compensation payable may be reduced or even lapse if the aggrieved party has intentionally or (grossly) negligently contributed to the damage.

The licence terms will usually require the licensee to take out insurance coverage for liability or the provision of other (financial) security. As regards offshore activities, membership of OPOL is mandatory for the operator of the activities.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Any licence for exploitation of hydrocarbons may only be granted to a public limited company domiciled in Greenland. Accordingly, the other forms of legal establishment (private limited company and branch of a foreign company) are not suitable for oil or gas licensees.

The formation of a public limited company requires one or more founders. The founders must sign a memorandum of association containing the articles of association of the company. Furthermore, the memorandum of association must contain information about, among other things, the rules concerning subscription to the share capital, formation costs, and the valuation of possible assets to be taken over by the new company. There are no residence requirements for the founders of companies in Greenland. A company may have one shareholder only, who may be a foreigner or a foreign entity.

ii Capital, labour and content restrictions

There are no restrictions in Greenland on movement of capital or access to foreign exchange.

According to the Act on the Regulation of the Accession of Labour to Greenland, an employer must prove that a vacancy cannot be filled by local workers before hiring foreign (also Danish) labour. The purpose of the act is to ensure the Greenlandic labour forces get priority access to work available in Greenland. However, to promote investment and completion of large-scale projects of particular importance to Greenland's economic development, Greenland has enacted the Act on Construction and Works in relation to Large-Scale Projects (the Large-Scale Act).

iii Anti-corruption

Procedures in Greenland generally operate in a transparent manner, with limited perceived exposure to or reputation of corruption. In March 2015, the MMRL introduced its zero tolerance policy on corruption. In accordance with international recommendations, the MMRL stated that it wants to forestall potential corruption risks by implementing a proactive anti-corruption policy. The policy also sets out guidelines applying to all employees of the MMRL and its subordinate institutions on how to respond to corruption and the risk of corruption. Zero tolerance applies to conflict of interest, bribery, fraud, extortion and other forms of corruption as detailed in the policy. Greenland has also enacted the Act against Money Laundering, setting out detailed measures against money laundering.

IX CURRENT DEVELOPMENTS

There is currently no available information on litigations or arbitrations concerning oil and gas operations in Greenland.

The government of Greenland most recently conducted a licensing round for the Davis Strait, with applications open until 15 December 2018. Additionally, the open-door procedure covering the onshore areas of Disko Island and the Nuussuaq Peninsula in West Greenland was open for applications until 31 December 2018. These marked the final stage
of the 2014–2018 Oil and Mineral Strategy, which the government saw through to the end, although expectations for bids were low. Accordingly, at the time of writing, no information about licences granted in these latest licensing rounds was available. With many hydrocarbon licences surrendered during past years and with surrender currently ongoing for additional licences, this could signal a grave outlook for the Greenlandic oil and gas activities.9 Nonetheless, Greenland’s self-government remains positive in its efforts to support an oil and gas industry. Accordingly, although no information has been published on a new overarching oil strategy, the Minister of Industry and Energy has expressed that the Greenlandic government will focus on promoting onshore exploration activity. The statement was made in connection with the news in March 2019 that Greenland Gas and Oil, a UK-based company focusing on Greenland, has been awarded a new licence and extended its existing licences for the onshore area of the Jameson Island east of Greenland.10 With this further licensing, the company plans to commence an exploration programme by 2020 that includes well drillings. In addition to the new licence for Jameson Island, a few prospecting licences have also been granted for West and North Greenland. Thus four licences have been applied for or granted since mid-2018, which may indicate that the negative trend has ended.

Additionally, Greenland’s national oil company, Nunaoil, announced in 2018 that it had initiated a comprehensive resource assessment project in order to identify the areas of Greenland that have the greatest petroleum exploration potential.11 The project is divided into seven assessments units covering a total of 2.4 million km², and the project is estimated to take three and a half years. As of August 2019, no official news has yet been published on its results.

The lack of interest in applications for licences may be ascribed to the recession in the investigation activities in the global oil and gas industry; however, despite the relatively open and transparent political and legal processes for licensing and production, the expenses of operating and harsh conditions in Greenland remain an obstacle to oil and gas production in a market with fluctuating (low) prices. Despite the recent news concerning new licence applications, it remains to be seen whether any exploration activities will lead to licensees initiating exploitation, whereby oil or gas production will become a reality in Greenland.

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9 A the list of exploration and exploitation licences (exclusive) in force and prospecting licences (non-exclusive) in force is published regularly by the MLSA, last released 1 July 2019, available at www.govmin.gl.
11 See the section on resource assessment on Nunaoil’s website, www.nunaoil.gl.
I INTRODUCTION

India is the third-largest energy consumer in the world, and oil and gas, as an energy resource, contributes 41 per cent of its total energy consumption. As of April 2018, the country had balance recoverable reserves of about 594 million metric tonnes of crude oil and about 1,233 billion cubic meters of natural gas. In 2017–18, crude oil production was about 35.68 million metric tonnes, and the natural gas production of the country was about 32.65 billion cubic metres. With this level of production, about 83 per cent of the crude oil and about 47 per cent of the natural gas consumed in India are imported.

The Indian government, from time to time, has adopted various licensing regimes with a view to enhance domestic production. As a general principle, an acreage awarded under a licensing regime continues to be regulated under such a regime, and any subsequently amended regime is applicable to acreages awarded under such regime. Therefore, at present different blocks are governed by different licensing regimes (depending on when they were awarded). The four broad categories of licensing regime that are presently applicable are discussed below.

Nomination regime (for blocks awarded till late 1970s)

Under this regime, the petroleum exploration licence (PEL) was granted to the two national oil companies – Oil India Limited (OIL) and Oil and Natural Gas Corporation Limited (ONGC) on a nomination basis.

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Pre-NELP regime (for blocks awarded between 1980 and 1995)

Pre-NELP Exploration Rounds: 28 Exploration blocks were awarded to private companies. OIL and ONGC were given the right to participate in the blocks after discovery. At present, 10 pre-NELP production sharing contracts (PSCs) are active.7

Regarding Pre-NELP discovered field or development rounds, for the small, medium-sized and discovered fields (proven reserves as discovered by ONGC and OIL), petroleum mining lease (PML) was granted to private parties for these fields. The Indian government has signed 28 contracts for 29 discovered fields. Out of these, 25 contracts are active.8

NELP regime (for blocks awarded between 1997 and 2010)

The new exploration licensing policy (NELP) was implemented from 1999.9

Blocks were awarded to companies (including private and foreign companies) through an international competitive bidding process.

The NELP regime was based on the ‘production sharing model’ (i.e., the Indian government is paid a part of the profits, after deducting the costs incurred by the contractor). The percentage of profit proposed to be paid by the contract was a biddable criteria.

Some 254 contracts were signed under nine licensing rounds. Out of these, 66 are active.10

One of the main issues with the regime is that there is an excessive oversight by the Indian government (through management committee), as the costs incurred by the contractors have to be approved by the Indian government.11

HELP Regime (for blocks to be awarded after 2016)

In order to further attract the private participation and foreign investments, in 2016, the Indian government introduced the hydrocarbon exploration and licensing policy (HELP).12

The key features of HELP include:

a uniform licence for exploration and production of all forms of hydrocarbon including non-conventional hydrocarbons such as shale gas, coal bed methane, tight gas, gas hydrates, etc.;

b an open acreage licensing policy (OALP) under which prospective bidders have the option to carve out exploration blocks. This process permits the interested parties to

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7 DGH Report, Indian E&P Sector at a glance.
8 DGH Report, Indian E&P Sector at a glance.
10 DGH Report, Indian E&P Sector at a glance.
11 Under the profit sharing model, the management committee (which includes the Indian government representatives) scrutinise cost details of private participants. This process has led to many delays and disputes in the past.
file expression of interest for two kinds of contracts: (1) reconnaissance contract (to undertake reconnaissance activities only); or (2) petroleum operations contract on a revenue share basis (to undertake exploration, development and production operations); a revenue sharing model; and marketing and pricing freedom for the crude oil and natural gas produced.

In contrast to the NELP regime, under which the contractor shared profits with the Indian government after recovery of costs, under the HELP regime, a revenue sharing model has been adopted (i.e., the contractor will share revenue with the Indian government). It is expected that this will reduce the Indian government’s oversight over the day-to-day operations and the delay owing to scrutiny by the Indian government of costs incurred by the contractors.

To date, three OALP bid rounds have been completed under the HELP regime wherein 87 blocks have been awarded.\(^{13}\)

In addition to the above, the Indian government also formulated the marginal field policy in 2015 with the objective of bringing the marginal oil and gas fields of the national oil companies to production at the earliest.\(^{14}\)

It may be noted that one of the significant changes that has been introduced by the Indian government recently has been the unification of licensing regime as applicable to conventional and non-conventional resources. Prior to the HELP regime, under the NELP regime, the contractors could explore and produce only conventional resources (i.e., crude oil, condensate and natural gas) but not CBM or shale. For unconventional resources, separate policies were formulated by the Indian government such as the CBM policy (1997)\(^ {15}\) and policy dated 14 October 2013 granting permission for shale gas and oil exploration and exploitation to national oil companies, for blocks awarded to these companies on nomination basis.\(^ {16}\) Under HELP, the contractors would be able to explore and produce unconventional resources under a single licence for the block. Further, the Indian government in August 2018 approved the policy on exploration of unconventional hydrocarbons policy to permit exploration and exploitation of unconventional hydrocarbons such as shale oil and gas and coal bed methane (CBM) under the existing PSCs, CBM contracts and nomination fields.\(^ {17}\)
Despite these aforementioned efforts of the Indian government, low levels of domestic production and failure to attract investments from foreign players are some of the key issues currently plaguing the sector. HELP, introduced in 2016, seeks to address some of these gaps. However, its effectiveness is yet to be seen.

II LEGAL AND REGULATORY FRAMEWORK

India has a federal constitution, where legislative powers are distributed between the central and the state legislatures. Pursuant to Article 246 of the Constitution of India, the regulation and development of oil fields, mineral oil resources, petroleum and petroleum products falls within the jurisdiction of the Union Parliament, that is, the federal legislative body of India. The state governments, on the other hand, have the power to regulate matters such as right of use and access land, labour, water and local government. Accordingly, while the contract for exploration and production of hydrocarbons is executed by the Indian government, the licences and approvals for undertaking activities relating to exploration and production for onshore blocks are to be obtained from state governments. For the offshore blocks, the Indian government has the licensing powers.

i Domestic oil and gas legislation

The following are the key pieces of legislation pertaining to upstream oil and gas sector:

a. the Oilfields (Regulation and Development) Act, 1948 (the Oilfields Act): The Oilfields Act is the primary legislation governing the upstream oil and gas sector. The Oilfields Act incorporates provisions relating to licensing and leasing of oil and gas blocks. In this regard, the Oilfields Act provides for rule-making power of the Indian government with respect to mining leases and mineral oil development and royalty rates to be paid by the holder of a mining lease;

b. the Petroleum and Natural Gas Rules, 1959 (the PNG Rules): The PNG Rules enacted under the Oilfields Act provides detailed provisions for the granting of licences and leases for both offshore and onshore areas. The PNG Rules prohibit prospecting or mining of petroleum except in pursuance of a PEL or a PML granted under the PNG Rules. By an amendment of July 2018, the definition of petroleum under the PNG Rules has been amended to include shale and other hydrocarbons. The amendment is in line with the HELP regime under which the licensing for conventional and non-conventional hydrocarbons has been unified;

c. the Mines Act, 1952 (the Mines Act) and Oil Mines Regulations, 2017: These detail provisions relating to health, safety and welfare of workers in oil mines. The Mines Act also highlight the duties of owners, agents and managers and the penalties in cases of contravention of the provisions; and

d. the Petroleum and Natural Gas (Safety in Offshore Operations) Rules, 2008 (the PNG Safety Rules): The PNG Safety Rules have been framed under the Oilfields Act and prescribe safety standards and measures to be taken for the safety of offshore oil

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18 INDIA CONST., Article 246 r/w Entry 53, List I of Schedule VII.
20 Oilfields Act, Sections 5 and 6.
21 Oilfields Act, Section 6A(1).
22 PNG Rules, Rule 4.
and gas operations. The PNG Safety Rules provide for the manner of preparation of information and records; various consents and intimations in relation to the offshore installations; safety, health and environment measures, etc., and prescribe the penalties for contravention of the PNG Safety Rules.

Apart from the above legislation, the Indian government from time to time promulgates policies, standards, directives and guidelines for governing various aspects of the upstream oil and gas sector (which amongst others include policies for the award of concessions for exploration of blocks and contractual structure to be followed).

### ii Regulation

The following are the key regulatory and administrative agencies concerned with the upstream oil and sector in India:

- **a** the Ministry of Petroleum and Natural Gas (MoPNG): This is the nodal ministry at the federal government level that supervises the exploration and production activities of petroleum and natural gas, and administers various pieces of legislation, including the Oilfields Act;

- **b** the Directorate General of Hydrocarbons (DGH): Pursuant to its resolution dated April 8, 1993, the MoPNG established the DGH with the objective of regulating and overseeing the upstream activities in the petroleum and natural gas sector and also to advise the MoPNG in these areas. The major responsibilities of the DGH include technical advisory to the MoPNG with respect to exploration and optimal exploitation of hydrocarbons and adequacy of development plans proposed by companies, review of exploration programmes, reassessment of reserves as discovered and estimated by companies and advising the Indian government on formulation of safety norms and regulations in oilfield operations. The DGH is not an independent regulator and works under the administrative control of the MoPNG;

- **c** the Oil Industry Safety Directorate (OISD): The OISD is the safety regulator for upstream offshore blocks operating under the MoPNG. It has been designated as the ‘competent authority’ for implementation of the Petroleum Safety Rules and exercises powers and functions under the PNG Safety Rules;

- **d** the Directorate General of Mines Safety (DGMS): This is the regulatory agency under the Indian government’s Ministry of Labour and Employment, and is responsible for safety of the onshore blocks; and

- **e** the Petroleum and Natural Gas Regulatory Board (PNGRB): This is the regulator for the midstream and downstream sector and has been empowered to regulate the refining, storage, transportation, distribution, marketing and sale of petroleum, petroleum products and natural gas. Therefore, transportation and evacuation of petroleum by pipelines outside the delivery point is subject to the PNGRB’s oversight and regulations with respect to, among others, tariffs and technical safety standards.

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24 Notification No. SO 1502(E), Ministry of Petroleum and Natural Gas, Government of India (8 June 2008).
In addition to the above, there are other general regulatory and administrative bodies looking into matters such as the environment, labour and tax that may be relevant for a company operating in the oil and gas sector in India.

iii Treaties

India is a signatory to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards, 1958 (the New York Convention) as well as the Geneva Convention on the Execution of Foreign Arbitral Awards, 1927. If a party receives a binding award from a country that is a signatory to either of the conventions, and is notified as a convention country by India, the award would then be enforceable in India subject to the satisfaction of the Indian courts of the enforceability of such awards. For enforcement of a foreign award, under either of the aforementioned conventions, the enforcing party has to fulfil certain requirements prescribed under the (Indian) Arbitration and Conciliation Act, 1996, such as production of arbitration award, etc.

India's bilateral investment treaties

From 1994 to 2015, India entered into 83 bilateral investment treaties (BITs), which were largely negotiated on the basis the Model BIT of 1993. In December 2015, India adopted a revised model text for its BITs. The Indian government proposes to replace the existing BITs with the revised text. In light of the proposed renegotiation of the BITs, in 2016, the Indian government issued notices to 58 countries to terminate the then applicable BITs after completion of the initial term. Accordingly, BITs executed with the 58 countries expired in 2017. Further, India has circulated a proposed joint interpretative statement to the counterparties for the 25 BITs for which the initial term has not been completed. The joint interpretative statement was issued to align the ongoing treaties with the text of the revised BITs and to clarify the ambiguities in the text of the existing treaty. Subsequent to the revised model text of 2015, BITs or statements (JISs) have been entered into with Colombia, Bangladesh and Belarus.

According to the United Nations Conference on Trade and Development (UNCTAD), which keeps an account of the number of investment disputes, a total of 30 known investor–state dispute settlement cases are pending against India. Further, there are six cases where India is the claimant.

26 ibid.
28 The Joint Interpretative Declaration with Colombia came into force on 4 October 2018.
29 The Joint Interpretative Note with Bangladesh came into force on 7 October 2017.
30 The BIT with Belarus was signed on 24 September 2018. Bilateral Investment Treaties (BITs)/Agreements, Department of Economic Affairs, Ministry of Finance, Government of India, https://dea.gov.in/bipa?page=7, Additionally, agreements with Brazil and Cambodia have been concluded and are yet to be signed, and agreements with 11 other countries including Iran, Switzerland, Hong Kong and Mauritius are under discussion.
Recent developments regarding India’s double taxation avoidance arrangements regimes

India has double taxation avoidance arrangements (DTAAs) with more than 80 countries, including Australia, Canada, Germany, Mauritius, Singapore, the UAE, the UK and the US. Recently, several of the existing DTAAs were amended. The most significant amendments have been to the DTAAs with Mauritius, Singapore and Cyprus to remove the exemption on capital gains tax on payable on sale of shares of an Indian company.32

III LICENSING

As noted under Section I, the licensing regime can be broadly categorised under nomination, Pre-NELP, NELP and HELP regime. PSCs have been entered into with contractors under the NELP and Pre-NELP regimes, and revenue sharing contracts (RSCs) are entered into for blocks awarded under the HELP regime. There have been organised licensing rounds (competitive bidding) under the NELP and HELP regime. However, there is a difference between the two regimes regarding the manner in which acreages are determined. While under NELP, the blocks on offer were determined by the Indian government, under HELP, the Indian government has introduced the concept of open acreage policy wherein the companies can choose the blocks from the designated area which are subsequently put for bidding.

Post the award of blocks and execution of the contract, the contractor is required to obtain a PEL for the entire contract area as per the provisions of the Oilfields Act and the PNG Rules. Under the terms of the PEL, the licensee is granted an exclusive right to operations relating to the information drilling or test drilling and right to lease over any part of the licence area.33 Subsequently, for carrying out development and production activities, the contractor is required to obtain a PML for parts of the contract area encompassing discoveries. Under the PML, the lessee has an exclusive right in the leased land to conduct mining operations for petroleum and natural gas and has the right to carry out construction in the leased area for full enjoyment of the lease or to fulfil the obligations under the lease.34

The Indian government has been empowered to grant PEL or PML in respect of any land vested in the union or in offshore areas and the state governments have the power to grant PEL or PML over the lands vested with the state government.35 The Territorial Waters, Continental Shelf, Exclusive Economic Zone and Other Maritime Zones Act, 1976 provides for the granting of licence by the Indian government to explore and exploit the resources of the continental shelf and exclusive economic zone.36

33 PNG Rules, Rule 7(i).
34 PNG Rules, Rule 7(ii).
35 PNG Rules, Rule 5.
IV PRODUCTION RESTRICTIONS

As per the provisions of the PNG Rules, the Indian government may, by way of a special or general order, restrict the amount of oil or gas to be produced, by a lessee in the respective allotted field, in the interest of conservation of oil resources. Further, the terms of contract provides that until India becomes self-sufficient, oil and natural gas produced in India is to be sold within the domestic market in India. Therefore, the freedom to sell hydrocarbons is limited to sale in India and the same cannot be exported.

The price at which the gas produced is to be sold has undergone various changes over the years, and pricing freedom, which is one of the key features of HELP, is a relatively new concept in the sector. A brief background of the gas pricing regime followed in India is as follows.

Prior to November 2014, the gas pricing regime was broadly divided under two heads: (1) administered pricing mechanism (APM); and (2) non-administered pricing mechanism (Non-APM). The APM regime covered the gas sold by state-owned oil and gas companies, from blocks which were given to them on nomination basis and under this mechanism, where the Indian government determined the price at which gas was to be sold. The Non-APM regime regulated the price of gas produced from the Pre-NELP blocks and NELP blocks. Under the Non-APM regime, the price of gas was to be determined based on the provisions of the PSC executed by the parties. Accordingly, the price of gas produced from the Pre-NELP blocks was determined by the Indian government, and the price of gas produced from NELP blocks was to be based on a formula approved by the Indian government.

In October 2014, in order to bring about uniformity in the gas pricing regime, the MoPNG notified the New Domestic Natural Gas Pricing Guidelines, 2014 (the Gas Pricing Guidelines), which took effect from 1 November 2014. The Gas Pricing Guidelines prescribe a formula for determining the well head price of gas produced, and this price is notified on a half-yearly basis by the Petroleum Planning and Analysis Cell (PPAC). The price determined in accordance with the Gas Pricing Guidelines was applicable to all gas produced in India, (including gas from Nominated Blocks, Pre-NELP blocks, NELP blocks and CBM blocks), except in specified circumstances.

In March 2016, the Indian government notified the Marketing including Pricing Freedom for the Gas to be produced from Discoveries in Deepwater, Ultra Deepwater and High Pressure-High Temperature Areas Guidelines, allowing pricing freedom for all discoveries in deepwater, ultra-deep water and high temperature-high pressure areas, which were yet to commence production as on 1 January 2016. Pursuant to these guidelines, the parties could sell gas at a price up to the ceiling price notified by PPAC on a half-yearly basis.

In March 2016, by introduction of HELP, contractors have marketing and pricing freedom with respect to all hydrocarbons produced. It may be noted that the HELP regime is applicable prospectively to the blocks allocated under HELP, and not to the blocks that were awarded prior to enforcement of HELP. Accordingly, unless otherwise notified, the Gas Pricing Guidelines, the Deep Water, Ultra Deep Water, High Pressure-High Temperature Area Guidelines, and the CBM Pricing Guidelines, will continue to be applicable to blocks awarded or nominated prior to enforcement of HELP.

The government, by its resolution dated 28 February 2019, has also permitted marketing and pricing freedom for new discoveries under existing contracts where the field

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37 PNG Rules, Rule 27.
development plan would be approved after the date of issuance of the policy. However, for nomination fields, this would be permitted subject to the approval of the DGH. The resolution clarifies that the Gas Pricing Guidelines and gas utilisation and allocation policy would not be applicable on these discoveries.

V  ASSIGNMENTS OF INTERESTS

As per the PNG Rules, the holder of a PEL or PML may assign its rights subject to the prior written approval of the government that has granted the licence or lease. Additionally, restrictions on the assignment of participating interests emanate from the applicable PSC or RSC as the case may be. The contractor is required to seek prior approval of the Indian government for: (1) assignment of participating interest; (2) mortgage of participating interest; (3) change in control of the member, or its parent company; or (4) change in relationship of the contractor with the companies providing guarantee (which is typically the parent company). Various foreign companies have raised concerns about this approval requirement, since any change of shareholding at the parent company of the contractor would require a prior approval of the Indian government, in the same manner as the assignment of the participating interest.

VI  TAX

i  Income tax

The Indian government enters into agreements with contractor entities for the joint performance of conducting exploration, development or production operations for oil and gas. Levy of income tax is computed as per the Income Tax Act, 1961 (the IT Act). The profits and gains of the entities participating in such operations is computed on the basis of the determined value and revenue realised on the sale of oil and gas as per the contract, reduced by applicable deductions as per the IT Act. Certain specific deductions in the terms of contract are also allowed in lieu of or in addition to corresponding allowances under ‘Profits and Gains of Business or Profession’ in the IT Act. These include expenditure incurred for exploration and drilling operations including infructuous or abortive exploration expense subject to prescribed conditions.

Non-residents engaged in the business of supplying plant, machinery, facilities or services in connection with prospecting or extraction of mineral oils are subject to a presumptive tax regime, wherein taxable profits are deemed to be 10 per cent (plus surcharge and education cess) of the gross revenues.

38  PNG Rules, Rule 17.
39  Model RSC, Article 26.3.
ii Goods and services tax (GST)

GST, a single tax on the supply of goods and services, formulates the indirect tax regime applicable in India. Under GST, credits of input taxes are available in the subsequent stage of value addition, making GST a tax only on value addition at each stage. Crude oil, petrol, natural gas, fuel jet and diesel are currently excluded from the ambit of GST levy, whereas, other oil products (such as liquefied petroleum gas, naphtha and kerosene) are included in the GST. As a result, upstream oil and gas companies will take advantage of input tax credit on GST paid only on the manufactured value added products covered under GST.\(^{42}\)

Tax paid on inputs (purchase of machinery, crude oil, etc.) is deducted from the tax on output for the final output product. Tax credits cannot be used for products excluded from GST as tax credit will not be transferred between the earlier and new taxation system. This is on account of procurement of goods and services for upstream and downstream sector being in the ambit of GST and the majority output being outside the purview of GST.\(^{43}\) This implies that the majority of GST paid on goods and services by oil and gas companies is a cost to them in addition to the cost of compliance under both the old and new tax regimes. This results in the end consumer bearing the burden for the increase in cost of such products.\(^{44}\)

Hence, oil and gas companies are to deal with the parallel system of taxation. While they incur GST charges on services and charges used for operations, they cannot offset this against value added tax and excise duty on output such as crude oil, diesel etc. resulting in stranded taxes.

iii Tax incentives

Various special allowances and incentives are applicable to companies engaged in the Indian oil and gas sector.

Foreign companies are exempt from tax on income earned from sale of crude oil to any consumer in India or storage of crude oil in any facility in India and its sale to any consumer in India. The conditions for the aforementioned are that (1) the income is earned in Indian currency; (2) the agreement for such sale and the foreign company are approved and notified by the central government; and (3) the foreign company does not have any other activity in India. Any income accruing or arising to a foreign company on account of sale of leftover stock of crude oil, if any, from the facility in India after the expiry of the agreement or the arrangement is also exempt from tax subject to certain conditions.

Allowance may be claimed in relation to expenditure made by way of infructuous or abortive exploration expenses for any area surrendered before commencement of commercial


\(^{44}\) ‘GST credit will be available only on value-added crude oil products’, The Hindu Business Line (21 August 2017), www.thehindubusinessline.com/economy/gst-credit-will-be-available-only-on-value-added-crude-oil-products/article9825371.ece.
production, drilling or exploration activities or services in respect of physical assets, and depletion of mineral oil in the mining area (subject to the terms of the agreement with the Indian government).  

Deduction is allowed for any capital expenditure incurred for ‘laying and operating a cross-country natural gas or crude petroleum oil pipeline network for distribution, including storage facilities being an integral part of such network’.  

In cases of new machinery or plant that have been acquired or installed after 31 March 2005, a sum of 20 per cent of actual cost of the machinery or plant is allowed as deduction. Further, where an undertaking is set up after 1 April 2015 in a notified backward area in states of Andhra Pradesh, Telangana or West Bengal, and any new machinery or plant is acquired or installed for such an undertaking, between 1 April 2015 and 1 April 2020, a 20 per cent deduction is increased to 35 per cent of actual cost of the machinery or plant.

VII  ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The environmental approvals and permissions that are required to undertake oil and gas operations in India include general environmental approvals as provided under the environmental legislations and specific approvals based on the location of the oilfield.

The general environment approvals include:

- environmental clearance: Under the Environmental Impact Assessment Notification of 2006 as notified under the Environment (Protection) Act, 1986 and the Environment (Protection) Rules, 1986, it is mandatory to obtain environmental clearance to undertake exploration and production activity in the oilfield;

- consent to establish and consent to operate: Under the Water (Prevention and Control of Pollution) Act, 1974 and Air (Prevention and Control of Pollution) Act, 1981, the consent to establish and consent to operate are required to be obtained by the respective state pollution control board; and

- authorisation for handling hazardous waste: Under the Hazardous Wastes (Management, Handling and Trans-boundary Movement) Rules 2016, authorisation from the state pollution control board is required for generating, processing, treating, packaging, storing and transporting waste (generated from drilling for oil and gas).

The approvals based on the location of the oilfield include:

- coastal regulation zone: Under the Coastal Regulation Zone Notification 2011, exploration and extraction of oil and natural gas in the coastal zone requires permission from the Ministry of Environment, Forest and Climate Change;

- forest clearance: If the exploration and production operations involve diversion of forest land, then forest clearance under the Forest (Conservation) Act, 1980 read with Forest (Conservation) Rules, 2003, is required to be obtained; and

- wildlife clearance: If the exploration and production activities are planned in and around protected areas such as national parks and wildlife sanctuaries, in addition to the environmental clearance and forest clearance, clearance under the Wildlife (Protection) Act, 1972 is also required.

45 Section 42 of the IT Act.
46 Section 35AD of the IT Act.
47 Section 32(iia) of the IT Act.
i  **Environmental Requirements specific to PSCs and RSCs**

Apart from the obligation contained under the environment laws, the PSCs and RSCs also provide for certain additional obligations in relation to protection of the environment. The terms of the contracts stipulate that the contractor shall conduct the petroleum operations with due regard to environmental protection concerns. In this regard, the contractors are required to adopt modern oilfield and petroleum industry practices and standards (under the terms of PSC) or good international petroleum industry practices and standards (under the terms of RSC) including advanced technologies, practices and methods of operations for the prevention of environmental damage. The relevant clause further provides that in the event of an emergency, such as accident, oil spill and fire, the contractor shall implement relevant contingency plan and perform such site restoration as may be necessary.

ii  ** Decommissioning and site restoration**

In relation to decommissioning and site restoration, the PNG Rules provide that on termination of the exploration licence or mining lease, the area and any wells contained in it must be delivered in good order and condition.\(^{48}\) For six months after the licence or lease ends, the former licensee or lessee can remove or dispose of any petroleum recovered during the licence or lease period, along with stores, equipment, tools and machinery and any improvements on the land covered by the licence or lease that the state government permits.\(^{49}\) The stores, petroleum, equipment, tools, machinery and other improvements to land that are not removed or disposed of can be sold at auction by the government.\(^{50}\)

As per the terms of the PSCs and RSCs, the contractors are required to remove all equipment and installations from the contract area in a manner as agreed with the Indian government pursuant to an abandonment plan. The contractor is required to prepare and submit a proposal to a management committee (comprising members of the Indian government and the contractor) for site restoration including abandonment plan and requirement of funds for site restoration, annual contribution.\(^{51}\) Further, the contractor is obligated to perform all necessary site restoration activities as under any specific guidelines, rules or regulations that has been formulated by the Indian government in relation to site restoration.\(^{52}\) In this regard, the site restoration and abandonment guidelines for petroleum operations have been issued by the Indian government, which prescribes provisions for obligations regarding decommissioning of offshore and onshore production sites.\(^{53}\)

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\(^{48}\) PNG Rules, Rule 22(1).

\(^{49}\) PNG Rules, Rule 22(2).

\(^{50}\) PNG Rules, Rule 22(3).

\(^{51}\) Model PSC, NELP-IX, Article 14.10; Model RSC, Article 14.8.

\(^{52}\) Model RSC, Article 4.

\(^{53}\) Site Restoration and Abandonment Guidelines for Petroleum Operations (April 2018).
direct investment (FDI) is permissible under the ‘automatic route’ (i.e., without the approval of the Indian government for exploration and production in oil and gas fields). Accordingly, a foreign company can undertake operations in the oil and gas sector either by itself or as a consortium with an Indian partner. A foreign company can undertake exploration and production activities in India without incorporating a company in India. Most foreign companies operating in this sector have setup a project office. The setting up of a project office is regulated under the Foreign Exchange Management (Establishment in India of a branch office or a liaison office or a project office or any other place of business) Regulations, 2016, as may be amended from time to time.

ii Capital, labour and content restrictions

As discussed above, 100 per cent FDI is permitted under the FDI policy and as per the provisions of FEMA, certain restrictions can be placed on the transactions based on their classification as current account transactions and capital account transactions. Current account transactions are permissible unless specifically restricted by the Indian government and all capital account transactions are specifically prohibited unless specifically permitted by the Indian government.

With respect to local content and employment to Indian citizens, the PSCs and RSCs provide that: (1) the contractor shall, to the maximum extent possible, employ (and require the operator and its subcontractors to employ) Indian citizens having appropriate qualifications and experience; and (2) give preference to the purchase and use of goods (equipment, materials and supplies) that are manufactured, produced or supplied in India subject to their timing of delivery, quality and quantity required, price and other terms.

iii Anti-corruption

The Prevention of Corruption Act, 1988 (PoCA) is the primary legislation for prevention of corruption in India. As per the amendment of July 2018 to PoCA, commercial organisations including companies that are either incorporated or undertaking business in India can be specifically charged as bribe givers and are punishable with fine. The Central Vigilance Commission (CVC) is the apex vigilance institution and is free from any executive control. The CVC, pursuant to the mandate granted to it under the Central Vigilance Commission Act, 2003, can conduct inquiries into allegations of offences committed under the PoCA by certain categories of public servants, government companies, societies and local authorities etc. The Black Money (Undisclosed Foreign Income and Assets) and Imposition of Tax

54 ‘Consolidated FDI Policy (effective from 28 August 2017)’, D/o IPP F. No. 5(1)/2017-FC-1, Department of Industrial Policy and Promotion Ministry of Commerce and Industry, Government of India.

55 As per the FEMA, ‘Capital account transaction’ means a transaction which alters the assets or liabilities, including contingent liabilities, outside India of persons resident in India or assets or liabilities in India of persons resident outside India, and includes transactions referred to under the provisions of FEMA; and ‘current account transaction’ means a transaction other than a capital account transaction and without prejudice to the generality of the foregoing such transaction includes: (1) payments due in connection with foreign trade, other current business, services, and short-term banking and credit facilities in the ordinary course of business; (2) payments due as interest on loans and as net income from investments; (3) remittances for living expenses of parents, spouse and children residing abroad; and (4) expenses in connection with foreign travel, education and medical care of parents, spouse and children.

Act, 2015 regulates the undisclosed foreign income and assets and imposes penal taxes on undisclosed foreign income and assets. Additional criminal liabilities have also been included under the legislation for non-disclosure of foreign assets and wilful attempts to evade taxes.

The Prevention of Money-laundering Act, 2002 (PML Act) and the Prevention of Money-Laundering (Maintenance of Records) Rules, 2005 prohibit and criminalise money laundering activities in India. Under the PML Act, ‘money laundering’ is defined as any process or activity connected with the proceeds of a crime listed in the schedule to the PML Act, and projecting or claiming it as untainted property.57 In order to prevent money laundering activities, the PML Act requires all banks, financial institutions and persons engaged in certain designated activities, to maintain records of all transactions undertaken. An operator of an upstream oil and gas block does not qualify as a reporting entity under the PML Act and the PML Rules. The Companies Act, 2013 also contains provisions with respect to statutory audits, corporate governance requirements, annual filing requirements among others that, inter alia, seek to prevent fraud and instances of money laundering. Further, pursuant to Section 216 of the Companies Act, 2013, the Indian government has the power to initiate investigation to find out the real beneficiary of a financial transaction undertaken by a company.

IX CURRENT DEVELOPMENTS

Some of the current developments in the sector are as follows.

The Indian government has been focusing on the implementation of the HELP regime. Under HELP, three bidding rounds have been completed whereby 87 blocks have been awarded to successful bidders. In these bidding rounds, minimum work programme and revenue share were biddable parameters with ‘revenue share’ having a weightage of 50 per cent. In February 2019, the government approved a ‘Policy framework on reforms in exploration and production of oil and gas’ pursuant to which the parameters under the policy would be applicable from the fourth bidding round. The policy focuses on exploration and highlights a shift from revenue maximisation to production maximisation.58 Some of the key reforms include the following:

a for Category I basins (that have established production): an increase in weightage of minimum work programme and decrease in weightage of revenue share for evaluation of bids, a ceiling of 50 per cent on revenue share at higher revenue point and a reduction in timelines for completion of minimum work programme;

b for Category II and III basins (that have contingent and prospective resources respectively): the award of exploration blocks solely on work programme and no production and revenue sharing (except in case of windfall gain);

c the grant of concessional royalty if production commences within four years in the case of onshore and shallow water blocks, and within five years for deep water and ultra-deep water blocks; and

57 Section 3 of the PML Act.
the constitution of a committee of external eminent persons or experts for dispute resolution. Parties under existing contracts may also choose to refer disputes and differences to the committee provided that the parties agree in writing and agree not to invoke arbitration under the applicable host government contract.

Additionally, the Discovered Small Fields Bid Round, 2016, has been concluded, wherein the approval for award of 31 contract areas (including 23 onshore and eight offshore areas) of discovered small fields has been granted. These contracts have been awarded under the revenue sharing model. Owing to the success of the first round, the Indian government in August 2018 had put on offer 59 unmonetised discoveries forming part of 25 contract areas under Discovered Small Fields Bid Round-II. Out of these, 23 (including 14 onshore and nine offshore areas) contract areas have been awarded.59

The government, on 10 October 2018, also issued a ‘Policy framework to promote and incentivise enhanced recovery methods for Oil and Gas’ to provide incentives to adopt (1) enhanced recovery, (2) improved recovery, and (3) unconventional hydrocarbon production methods.60 The main objective of the policy is to encourage and incentivise contractors engaged in the upstream oil and gas sector to adopt the aforementioned methods and techniques to enhance oil and gas production from the blocks.

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INDONESIA

Darrell R Johnson and Fransiscus Rodyanto

I INTRODUCTION

Indonesia’s proven oil reserves at the end of 2018 amounted to 3.2 billion barrels, with production at 39.5 million tonnes per annum. With respect to gas, Indonesia’s proven gas reserves at the end of 2018 were 97.5 trillion cubic feet, with production amounting to 62.9 million tonnes per annum.²

Oil and gas business activities in Indonesia are divided into the upstream sector (exploration and exploitation) and the downstream sector (processing, transportation, storage, and trading).

In 2017, Indonesian President Joko ‘Jokowi’ Widodo issued a regulation³ classifying a number of upstream oil and gas projects as national strategic projects in an effort to increase Indonesian oil and gas production. Classifying these as national strategic projects allows the government, through the Coordinating Ministry for Economic Affairs, to make sure these projects can be put on stream immediately by expediting the infrastructure required for the projects and the issuance of regulations for their implementation. The national strategic upstream oil and gas projects are:

<table>
<thead>
<tr>
<th>No.</th>
<th>Project name</th>
<th>Operator</th>
<th>Onstream schedule</th>
<th>Expected production</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.</td>
<td>Abadi Field Project</td>
<td>Inpex Masela, Ltd</td>
<td>2027</td>
<td>10.5 million tonnes of gas per annum</td>
</tr>
<tr>
<td>2.</td>
<td>Indonesia Deepwater Development</td>
<td>PT Chevron Pacific Indonesia</td>
<td>2024</td>
<td>1.120 million standard cubic feet of gas per day and 40,000 barrels of oil per day</td>
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<tr>
<td>3.</td>
<td>Jambaran-Tiung Biru Field</td>
<td>PT Pertamina EP Cepu</td>
<td>2021</td>
<td>190 million standard cubic feet of gas per day</td>
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<tr>
<td>4.</td>
<td>Tangguh Train-3</td>
<td>BP Berau BV</td>
<td>2020</td>
<td>3.8 million tonnes of LNG per annum</td>
</tr>
</tbody>
</table>

The Indonesian oil and gas industry, like the global industry, has experienced significant difficulties due to the collapse of global oil prices. While oil prices are beginning to return to more normal levels, the government still faces the problem of a lack of new reserve discoveries. Part of this is because of the overall struggles of the global industry, but it would also be difficult to ignore the role of domestic regulatory and bureaucratic issues, specifically for foreign investors. To attract new business players to the upstream oil and gas industry, President Jokowi, through the Minister of Energy and Mineral Resources (MEMR), has

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¹ Darrell R Johnson is senior of counsel and Fransiscus Rodyanto is a partner at SSEK Legal Consultants.


³ Presidential Regulation No. 58 of 2017 regarding Amendment to Presidential Regulation No. 3 of 2016 regarding Acceleration of the Implementation of National Strategic Projects (16 June 2017).
attempted to clarify and simplify the regulatory regime of the oil and gas industry. These efforts include the issuance of tax incentives and facilities, the revocation of exploration permit requirements, and the relaxation of restricted positions for expatriate employment, as discussed in greater detail below.

In general, upstream oil and gas business activities by oil companies are based on a contract, known as a production sharing contract (PSC), between the government, (through the Special Task Force for Upstream Oil and Gas Business Activities (SKK Migas), and the oil company as a PSC contractor. Up until 2017, there was only one form of PSC, with a cost-recovery mechanism, called a cost recovery PSC. In January 2017, the MEMR introduced a new PSC scheme based on a gross production split without a cost-recovery mechanism, called the gross split PSC.

Other major recent developments include:

- **a** MEMR Regulation No. 15 of 2018 regarding Post-Operation Activities in Upstream Oil and Gas Business Activities (MEMR Reg 15/2018), which requires PSC contractors to carry out post-operation activities and deposit funds for post-operation activities in a joint account of SKK Migas and the PSC contractor;
- **b** MEMR Regulation No. 42 of 2018 regarding the Priority to Use Crude Oil for Meeting Domestic Needs (MEMR Reg 42/2018), which requires PSC contractors to prioritise offering their crude oil portion to Pertamina, an Indonesian state-owned oil and natural gas corporation, before exporting the crude; and
- **c** Government Regulation No. 1 of 2019 on Export Proceeds from Exploitation, Management and/or Processing Activities of Natural Resources (GR 1/2019), which requires foreign exchange proceeds derived from the export of natural resources, including oil and gas, to be placed in a special account in an Indonesian foreign exchange bank.

The above developments have become an issue for existing PSC contractors whose PSCs do not provide these requirements and indeed specifically allow funds from oil and gas sales to be held and retained abroad.

## II LEGAL AND REGULATORY FRAMEWORK

### i Domestic oil and gas legislation

**Main legislation specific to upstream oil and gas, including summary of key provisions**

The upstream oil and gas sector in Indonesia is mainly regulated by Law No. 22 of 2001 regarding Oil and Natural Gas (the Oil and Gas Law). Further provisions are regulated under Government Regulation No. 35 of 2004 regarding Upstream Oil and Natural Gas Business Activities, as amended most recently by Government Regulation No. 55 of 2009 (GR 35/2004).

In general, the Oil and Gas Law grants the government the exclusive right to oil and gas exploration and exploitation, and requires all private companies that wish to explore and exploit oil and gas resources to enter into cooperation contracts with the government through SKK Migas. Such cooperation contracts most often take the form of a PSC.

There are currently two types of PSCs used for Indonesian upstream oil and gas business activities. Before 2017, all PSCs contained a cost recovery scheme, where PSC contractors could obtain reimbursement of their operating costs through the production of oil and gas. In mid-January 2017, the government introduced gross split PSCs with no cost recovery...
arrangements. Under a gross split PSC, the government allowed PSC contractors a higher production split than that allowed under the cost recovery scheme but all costs had to be borne by the PSC contractors.

The key provisions of the Oil and Gas Law include the following: (1) the government’s entitlement to oil and gas resources up to the delivery point; (2) SKK Migas’ control over the management of oil and gas operations; (3) all capital and risks of oil and gas operations are to be borne by PSC contractors; (4) one company can only hold one oil and gas working area; (5) the term of a PSC is 30 years, which can be extended a maximum of 20 years; and (6) PSC contractors are obligated to provide 25 per cent of their production share to fulfil domestic demands.

ii Regulation

Regulatory agencies with responsibility for upstream oil and gas

The regulators’ powers

The MEMR, through the Directorate General of Oil and Gas (DGOG), oversees affairs in the energy and mineral resources sector, including supervision of the implementation of oil and gas business activities, preparation of policies for the upstream oil and gas business sector, determination of cost-recoverable and non-cost-recoverable activities in the upstream oil and gas business, and issuance of approvals related to upstream oil and gas activities, such as the first plan of development (POD), the transfer of participating interests, and direct and indirect change of control of the entities holding a PSC.

With the issuance of the Presidential Regulation No. 9 of 2013 regarding Management of Upstream Oil and Gas Activities, as amended by Presidential Regulation No. 36 of 2018, the upstream sector is managed and supervised by SKK Migas. In general, SKK Migas has the right to organise the management of upstream oil and gas activities, to the extent the management is in accordance with the relevant PSC. The Head of SKK Migas reports directly to the President. In performing its duties, SKK Migas is supervised by a supervisory committee, consisting of the MEMR, a Deputy MEMR, a Deputy Minister of Finance (MOF) and the Head of the Capital Investment Coordinating Board.

Currently, a draft oil and gas law is being finalised by the House of Representatives. One of the anticipated changes in the new law includes the establishment of a Specific Oil and Gas Business Entity (BUK Migas), which will take over the current authorities of SKK Migas and also manage downstream oil and gas activities.

PSC contractors’ activities are subject to audit by the government. The auditing authority rests with the Agency for Finance and Development Supervision (BPKP). Based on GR No. 60 of 2008 regarding the government’s internal management system, the BPKP has the authority to audit the state treasury as part of an internal government audit. These audits include state revenue and expenses including the allocation of cost-recovery costs under the state budget. With respect to the audit of income tax obligations, a joint audit will be conducted by BPKP, SKK Migas, and the Directorate General of Taxation, based

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4 Initially, the government through the Oil and Gas Law granted the authority over the management of upstream oil and gas operations to the Implementing Body of Upstream Oil and Gas Activities (BP Migas). However, a Constitutional Court Decision in 2012 disbanded BP Migas by declaring that its authority was unconstitutional. Afterward, the authority was transferred to a newly established entity, SKK Migas, through the issuance of Presidential Regulation No. 9 of 2013 regarding Management of Upstream Oil and Gas Activities, as amended by Presidential Regulation No. 36 of 2018.
on MOF Regulation No. 34/PMK.03/2018 regarding Implementing Guidelines for Joint Audits of the Implementation of Cooperation Contracts in the Form of Production Sharing with Recovery of Operating Costs in the Upstream Oil and Gas Business.

iii Treaties

While Indonesia does not recognise foreign court decisions, international arbitration awards can be enforced in Indonesia through mechanisms provided in Law No. 30 of 1999 regarding Arbitration and Alternative Dispute Resolution. In general, Indonesia has bound itself to enforce foreign arbitral awards if (1) the award is rendered by a tribunal in a country bound by the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the Convention) or a bilateral treaty with Indonesia; (2) the dispute is commercial in nature, as that term is understood under Indonesian law and the Convention; and (3) the award does not contravene Indonesian law or notions of public order or policy.

International treaties and other multinational agreements are binding upon Indonesia after ratification, which may be done by way of a law to be approved by the House of Representatives, or by way of a presidential regulation to be further implemented by a ministerial regulation, which will be notified to the House of Representatives. All regulations and decrees issued afterwards must not deviate from the provisions of the international treaty or the national regulation enacted in light thereof. Therefore, once an international treaty is binding upon the government, regulatory policy or activity shall develop in accordance with the international treaty. Indonesia is a party to, among others, the United Nations Convention on the Law of the Sea (UNCLOS), the 1987 Montreal Protocol, and the International Convention on Civil Liability for Oil Pollution Damage and the protocols and amendments thereof.

Indonesia has entered into many bilateral tax treaties with other countries to avoid the imposition of double taxation in both countries. As of 2019, Indonesia has 66 double tax treaties with contracting states including Australia, France, Japan, Malaysia, Singapore, the United Arab Emirates and the United States.

III LICENSING

The right to explore oil and gas is provided by the execution of cooperation contracts, generally based on a production sharing scheme through a PSC between the government, through SKK Migas, and the company that wins the right to the working area covered by the PSC. Pursuant to MEMR Regulation No. 35 of 2008 regarding Procedures for the Stipulation and Tender of Oil and Gas Working Areas, a working area can be offered either through a direct offer or a tender. In a direct offer, a company that performs a technical assessment through a joint study with the DGOG will receive the right to match the highest bidder of the tender round. Most new working areas are awarded through a tender process.

A PSC is granted for 30 years, typically comprising six plus four years of exploration and 20 years of exploitation. A PSC that has entered into the exploitation phase shall be subject to cost recovery. The production output of the traditional cost recovery PSC is subject to a first tranche petroleum (FTP) requirement where 10 per cent of oil and gas production shall be given to the government first and the remaining portion will be distributed between the PSC contractor and the government based on the production split proportions set out in each PSC, cost recovery and certain taxes.
In 2017, MEMR Regulation No. 8 of 2017 regarding gross split PSCs, as amended by MEMR Regulation of 52 of 2017, introduced a gross split production sharing scheme through a gross split PSC. The gross split is agreed through negotiations with SKK Migas, and the production output is split at gross without FTP or cost recovery, stipulated at the beginning of a field’s development and subject to fluctuation depending on certain variables and progress components.

In general, GR 35/2004 provides that a PSC should at least contain the following provisions: state revenues, the working area and its relinquishment, obligatory funding expenses, the transfer of ownership of oil and gas production, the contract period and contract extension requirements, settlement of disputes, the obligation to supply crude oil or natural gas (or both) for domestic needs, post-mining operation obligations, occupational health and safety, environmental management, the transfer of rights and obligations, reporting requirements, field development plans, preferential utilisation of domestic goods and services, the development of the surrounding community and a guarantee of the rights of nearby traditional communities and the prioritisation of the use of Indonesian workers.

Below is a table summarising brief key differences between cost recovery and gross split PSCs.

<table>
<thead>
<tr>
<th>Description</th>
<th>Cost recovery PSCs</th>
<th>Gross split PSCs</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production sharing split</td>
<td>Depending on each PSC, typically 65:35 between the government and the PSC contractor for oil, and 60:40 between the government and the PSC contractor for gas.</td>
<td>57:43 between the government and the PSC contractor for oil, and 52:48 between the government and the PSC contractor for gas, both of which can be increased based on: • variable components (i.e. working area status, field location, reservoir depth, infrastructure availability, reservoir type, CO₂ content, H₂S content, specific gravity, local content achievement, production phase); and • progressive components (i.e. oil or gas price and cumulative oil or gas production). It has been reported that one gross split PSC (for a mature field) was set at 42.5:57.5 between the government and a PSC contractor.*</td>
</tr>
<tr>
<td>Approvals required</td>
<td>Approvals are provided for work programmes and budgets (WP&amp;B) and the POD, and the Authorisation for Expenditure (AFE)</td>
<td>Approvals are provided for the POD.</td>
</tr>
<tr>
<td>Recovery of costs</td>
<td>All allowable current costs as well as amortised exploration and capital costs</td>
<td>None.</td>
</tr>
<tr>
<td>Procurement of goods and services</td>
<td>Regulated under the prevailing working guidelines issued by SKK Migas</td>
<td>Managed independently by each PSC contractor, not based on SKK Migas working guidelines.</td>
</tr>
</tbody>
</table>

The continuation of operations following the expiration of the term of a relevant PSC is regulated under MEMR Regulation No. 23 of 2018 regarding the Management of Oil and Gas Working Areas with Expiring PSCs, as most recently amended by MEMR Regulation No. 3 of 2019. This regulation provides that upon the expiry of a PSC, a PSC may either be taken over by Pertamina, extended, jointly operated by Pertamina and the PSC contractor, or tendered to the public.
**IV PRODUCTION RESTRICTIONS**

Oil and gas production remains owned by the state until its possession is delivered at the point of export or other delivery point. Once it reaches the point of export or other delivery point, the PSC contractor is entitled to any production of oil and gas based on the production split as regulated under the PSC.

The PSC contractor can take its share of the oil and gas production in kind. For oil production, the PSC contractor may take its oil production share in kind and sell it with the option not to commingle the sale with the government’s share of oil production. For gas production, in practice, the PSC contractor's and the government’s share of production are sold jointly.

Exports of oil and gas are subject to the fulfilment of the Domestic Market Obligation (DMO) and the initial domestic offering under MEMR Reg 42/2018. This regulation requires PSC contractors or their affiliates to offer their crude oil portion to Pertamina or holders of the crude oil processing licence, or both, through a negotiation process on a business-to-business arrangement no later than three months before commencing the export recommendation period for the PSC contractor’s entire portion of crude oil. Through the negotiation process, Pertamina may directly appoint a PSC contractor for the purchase of the crude oil, which may be made in the form of a long-term contract with a term not to exceed 12 months.

In January 2019, the government issued GR 1/2019. This regulation requires foreign exchange proceeds derived from the export of natural resources, including oil and gas, to be placed in the Indonesian financial system through a special account in an Indonesian foreign exchange bank, which must be licensed by the Financial Services Authority. The Indonesian branch offices of overseas banks do not satisfy this requirement. The placement of the export proceeds in a special account must be carried out no later than the end of the third month after the registration of export declaration. The funds in the special account can only be utilised by the PSC contractor for certain payments, such as customs, loans, imports, profits or dividends, and other purposes permitted by the Indonesian Investment Law (namely Law No. 25 of 2007 regarding Capital Investment).

A PSC contractor is required to fulfil the DMO by supplying oil or gas, or both, to meet domestic needs. The participation of the PSC contractor is determined on a prorated basis in accordance with its share of total oil and gas production. Typically, the amount of the PSC contractor’s participation is 25 per cent of the oil and gas production, subject to stipulation by the MEMR. In the past, there was no DMO requirement related to gas production. A DMO requirement for gas was introduced in PSCs that were signed after the issuance of the Oil and Gas Law.

The value of oil to determine the sharing of production and for tax purposes must be not less than the Indonesian crude price (ICP). With respect to gas, the relevant gas sales contract is based on negotiations on a field-by-field basis between SKK Migas, buyers and individual producers. There is a requirement that the determination of gas prices by a PSC contractor must follow the considerations provided under MEMR Regulation No. 6 of 2016 regarding Provisions and Procedures for Determining the Allocation, Utilisation and Price of Gas, namely the economics of a particular gas field, domestic and international gas prices, and the added value of the domestic utilisation of gas. After determining the gas price, it must be submitted to the MEMR, through SKK Migas, for approval.
V ASSIGNMENTS OF INTERESTS

PSCs contain different approval requirements for the transfer of participating interests, depending on when they were entered into. For a transfer to an affiliated company, some PSCs do not require any approval. For a transfer to a non-affiliated company, PSCs require either the approval of the MEMR, the MEMR and SKK Migas, or the MEMR through SKK Migas. As noted, the different approval requirements depend on the generation of the signed PSC.

For the sake of unification, the MEMR issued MEMR Regulation No. 48 of 2017 regarding Business Supervision in the Energy and Mineral Resources Sectors (MEMR Reg 48/2017), which requires prior approval from the MEMR, through SKK Migas, to transfer a participating interest to affiliated or non-affiliated companies. In practice, the government currently refers to the transfer of participating interest approval requirements in MEMR Reg 48/2017 rather than those set forth in individual PSCs.

It is to be noted that GR 35/2004 and MEMR Reg 48/2017 prohibit a PSC contractor from transferring its majority participating interest to a non-affiliated party within the first three years of the PSC contractor’s exploration period.

A change of control through the transfer of a majority of the shares of a PSC contractor, on the other hand, does not always require the approval of the MEMR (through SKK Migas). A change of control can take one of two forms, namely a direct change of control and an indirect change of control. MEMR Reg 48/2017 defines ‘direct control’ as the direct ownership by a parent company being one level above through the ownership of a majority of the shares having voting rights. It is commonly understood that ‘indirect control’ means transfer of shares by a parent company beyond one level above that owns a majority of the shares with voting rights in a PSC contractor.

Only PSCs signed in 2008 and later require approval for a direct and indirect change of control, either from the MEMR, through SKK Migas, or from both the MEMR and SKK Migas. MEMR Reg 48/2017 requires the prior approval of the MEMR, through SKK Migas, for a direct change of control and notification to the MEMR, through SKK Migas, for an indirect change of control, which is typically given after the transaction has been completed. In practice, the government currently refers to MEMR Reg 48/2017 and not PSCs for the approval and notification requirement for direct and indirect changes of control.

The government does not have a right of first refusal or preferential purchase rights upon a transfer of a participating interest or a change of control. Other than imposing a final tax to be paid out of the consideration for any transfer of a participating interest or change of control (i.e., 5 per cent for a transfer during the exploration stage and 7 per cent for a transfer during the exploitation stage), the government does not impose any other requirements with respect to the consideration for any transfer of a participating interest or a change of control. Therefore, the consideration can be agreed between the parties in the transfer documentation.

A PSC contractor is required, under MEMR Regulation No. 37 of 2016 regarding the Requirement to Offer a 10 per cent Participating Interest in an Oil and Gas Block (MEMR Reg 37/2016), to offer through SKK Migas a 10 per cent participating interest to a regionally owned business entity (BUMD) or state-owned business entity (BUMN) after the first commercial discovery. In essence, MEMR Reg 37/2016 regulates that following the first approval of a POD, SKK Migas will notify the governor of the relevant working area. Within a period of one year, the governor must prepare a BUMD and submit a letter to SKK Migas indicating the appointment of the BUMD. SKK Migas will deliver the letter to the relevant PSC contractor requesting it to start the offer process to the BUMD. If the BUMD rejects
the PSC contractor’s offer (or if the governor does not submit the letter to SKK Migas), the PSC contractor must offer the 10 per cent participating interest to a BUMN. There is no regulation that establishes the purchase price or the valuation method for the 10 per cent participating interest.

VI  TAX

Taxes that are applicable to PSCs include income tax, value added tax, import duties, regional taxes and other levies. Each PSC may stipulate whether the tax laws and regulations applicable at the time the PSC was executed shall apply or whether the PSC shall follow changes to tax laws and regulations that are issued over time. Currently, the income tax rate is 25 per cent. VAT has a rate of 10 per cent, which is imposed on the provision of services and may be reimbursed with respect to cost recovery PSCs. Branch profits tax (BPT), which is assessed on the after-tax profits of a PSC contractor’s permanent establishment (i.e., a foreign entity as discussed below), also applies and has a rate of 20 per cent, subject to reduction under an applicable tax treaty. If the PSC contractor is a business entity (i.e., an Indonesian entity as discussed below), the BPT is not applicable; however, its disbursements of dividends are subject to a withholding tax of 20 per cent, from which an exemption can be obtained if (1) the dividend is derived from retained earnings of the business entity, or (2) the recipient of the dividend is a legal entity holding at least 25 per cent of the shares in the business entity.

In addition, PSC contractors are required to pay non-tax state revenues such as exploration and exploitation fees and bonuses, including signing bonuses and production bonuses, which vary depending on the PSC.

Currently, tax arrangements for cost recovery PSCs are regulated under Government Regulation No. 79 of 2010, as amended by Government Regulation No. 27 of 2017 (GR 79/2010). Tax arrangements applicable for gross split PSCs are regulated under Government Regulation No. 53 of 2017 regarding Tax Treatment for Upstream Oil and Gas Business Activity through Gross Split PSCs (GR 53/2017).

In general, both GR 79/2010 and GR 53/2017 regulate the taxation of the production sharing income and non-production sharing income of PSC contractors. Both Regulations allow certain tax incentives and tax facilities. The tax facilities under GR 79/2010 and GR 53/2017 are similar. During both the exploration and exploitation stages, there is an exemption from import duty for the import of goods used in the context of petroleum operations, an exemption from VAT or Luxury Goods Sales Tax for certain goods and services used in the context of petroleum operations, a reduction in the Land and Building Tax (PBB) amounting to 100 per cent, which is applicable during the exploration stage, and a reduction of subsurface PBB amounting to 100 per cent, which is applicable during the exploitation stage. Tax facilities in the exploitation stage will be granted by the MOF based on its consideration of project economics. GR 79/2010 provides tax incentives including a DMO holiday (with no time limit specified), a range of tax incentives as long as they are in accordance with the prevailing tax laws and a range of non-tax state revenue incentives including the use of state-owned assets for upstream activities.
VII  ENVIRONMENTAL IMPACT AND DECOMMISSIONING

PSC contractors are required to comply with the provisions of occupational health and safety, environmental management, and community development regulations. In the exploration stage, PSC contractors must complete an environmental monitoring and environmental management report (UKL/UPL). In the exploitation stage, PSC contractors must further conduct an environmental assessment (AMDAL), which must be approved by the relevant government authority. PSC contractors are also required to make periodic reports to the relevant government authority regarding their compliance with the UKL/UPL or AMDAL. In addition, Law No. 32 of 2009 regarding Protection and Management of Environment requires PSC contractors to obtain an environmental licence from the Minister of Environment and Forestry. While the DGOG is responsible for supervising the implementation of health, safety and environment (HSE) regulations in the oil and gas sector and imposing sanctions for non-compliance, it designates mining inspection enforcement teams to examine the work safety compliance of oil and gas businesses. If the facilities and techniques satisfy work health and safety standards, the DGOG will issue certifications for installations and equipment. In the event that a company does not comply with applicable HSE rules, it will be subject to various administrative sanctions ranging from warnings to the revocation of its licence.

The Oil and Gas Law highlights post-operation obligations as a means of ensuring environmental management and protection, and GR 35 obligates contractors to allocate funds for post-operation activities. In 2018, the MEMR issued MEMR Reg 15/2018 on abandonment and site restoration activities, or post-operation activities. This Regulation requires PSC contractors to carry out post-operation activities before or on the expiry of the PSC. Post-operation activities include well-plugging, site restoration and managing the disposal of equipment, installations and facilities. These post-operation activities must be initially reported to SKK Migas through the submission of a WP&B (if the PSC is in the exploration stage) or through a POD (if the PSC is in the exploitation stage). PSC contractors are also required to deposit funds for post-operation activities in a joint account between SKK Migas and the PSC contractor in an Indonesian state-owned bank. The deposited funds must be in accordance with the estimated costs in the post-operation activities plan submitted to SKK Migas. Other specific decommissioning obligations include land reclamation and the dismantlement of facilities that are no longer used.

VIII  FOREIGN INVESTMENT CONSIDERATIONS

i  Establishment

Timing and procedure for establishment of a local entity or branch of a foreign entity.

Under the Oil and Gas Law and GR 35/2004, upstream oil and gas business activities may be carried out by a business entity or a permanent establishment (PE). A business entity is a legal entity established under the laws of Indonesia and operating and domiciled in Indonesia. It may be in the form of a state-owned enterprise, a regional administration-owned company, a cooperative, a small-scale business or a private business entity. A PE is a business entity established and existing outside the territory of Indonesia that engages in activities within the territory of Indonesia and is subject to prevailing Indonesian laws and regulations. An offshore subsidiary holding the participating interest in a PSC is considered a PE.

A business entity can be in the form of a wholly Indonesian-owned company (PMDN) or a partially or wholly foreign-owned company (PMA). Please note that under the Oil and
Gas Law, only one PSC may be granted to each company, meaning that one company cannot hold a participating interest in more than one PSC. However, several companies can own participating interests in a single PSC.

Before a PMDN or PMA can be established, it must meet the minimum capital requirements, which are significantly higher for a PMA. The establishment of a PMDN is less complicated; it can freely determine its line of business and may freely modify or change its line of business by simply amending its articles of association. A PMA must comply with foreign ownership requirements by referring to the prevailing negative investment list issued by the government. In the current negative investment list, upstream oil and gas activities are open to 100 per cent foreign ownership. The process for establishing a PMDN and PMA consists of the preparation of a deed of incorporation by a notary, approval of the deed by the Minister of Law and Human Rights, and the issuance of a taxpayer registration number (NPWP). With the establishment of the single-window licensing platform, called the online single submission (OSS) system, through the issuance of Government Regulation No. 24 of 2018 regarding Electronic Integrated Business Licensing Services (GR 24/2018), a PMDN and PMA in the oil and gas sector must be registered in the OSS system to obtain a business identification number (NIB). The establishment process can take a total of three to four weeks.

The establishment of a PE, on the other hand, is significantly simpler. Other than a requirement to obtain an NPWP, it only has to register with the OSS system to obtain an NIB, which is required by common practice despite GR 24/2018 not specifically requiring a PE to do so. In total, the establishment process can take three to four weeks.

**ii Capital, labour and content restrictions**

In the Indonesian oil and gas sector, capital refers to funds that are disbursed during the operation of the PSC. For cost recovery PSCs, the only restriction on the movement of funds is that a PSC contractor’s funds during the implementation of the PSC can only be disbursed to the extent it is in accordance with the yearly WP&B or AFE, or both, approved by SKK Migas. Any excess of funds requires a separate approval from SKK Migas. Gross split PSCs do not contain any restriction on the utilisation of funds during the implementation of PSC operations as the budgets are not approved by SKK Migas.

Bank Indonesia Regulation No. 17/3/PBI/2015 regarding the Mandatory Use of Rupiah (PBI 17/2015) restricts most transactions within the Indonesian territory from being carried out using foreign currency. Bank Indonesia Circular Letter No. 17/11/DKSP was issued as an implementing regulation for PBI 17/2015 and it exempts oil and gas infrastructure projects from the required use of rupiah for transactions. To obtain the exemption, the project owner must seek confirmation from the relevant ministry and obtain a waiver letter from Bank Indonesia.

SKK Migas Working Guideline No. PTK-007/SKKMA0000/2017/S0 (Revision 04) Book Two regarding Guidelines for the Implementation of Goods/Services Procurement requires business players to prioritise local goods, services, technology, and design and engineering, so long as they are of comparable quality, price and availability. Indonesian-made equipment must be purchased if it meets the requirements, even if the cost of the equipment is higher than foreign-made equipment. Local goods must be given preference if their price is within 15 per cent of the lowest tender price and within 7.5 per cent for local services. Goods, services, technology, and design and engineering can be imported if they are not produced domestically. These Guidelines do not apply to gross split PSCs.
Indonesia

PSCs require that PSC contractors give preference to qualified Indonesian personnel and train such personnel for staff positions, including in administration and executive management. The Oil and Gas Law also requires PSC contractors to prioritise Indonesian personnel. PSC contractors may employ expatriates if the expertise is unavailable in Indonesia. In 2018, the government relaxed the restricted positions for expatriates in the oil and gas sector by revoking MEMR Regulation No. 31 of 2013 regarding the Procedures to Utilise Expatriates in Oil and Gas Activities. This is supervised by way of expatriate and local manpower utilisation plans submitted by the PSC operator to SKK Migas for its review and approval.

iii Anti-corruption

The relevant anti-corruption laws and regulations in Indonesia consist primarily of the Indonesian Criminal Code, Law No. 11 of 1980 regarding Bribery and Law No. 31 of 1999 regarding the Eradication of Criminal Acts of Corruption (the Corruption Law). The Corruption Law applies to government officials or any other person who commits an illegal act to enrich himself or herself or who favours himself or herself or abuses power, opportunity or facilities, which in either case may harm state finances and the national economy. Any person who accepts or makes any gift in kind or payment in view of a government official’s position or authority is guilty of an act of criminal corruption, whether or not a loss is suffered by the state as a result.

Despite having laws and regulations for the prevention of corruption in Indonesia, anti-corruption efforts have proven difficult to implement. Historically, major corruption cases have resulted in the issuance of new regulations, in the hope they would eradicate corruption practices in the future. One example of this involves Pertamina, which in the past served as both regulator and operator, prompting the issuance of the Oil and Gas Law to end Pertamina’s regulatory rights.

Research by the professional services firm Ernst & Young found that the highest risk of corruption was among vendors that provide goods and services to PSC contractors, during the procurement process and related to permitting and licensing. In 2013, the head of SKK Migas was arrested for taking bribes from a Singaporean oil company as part of a tender. Also, the complicated procedures for obtaining the numerous exploration licences required have created an environment conducive to bribery, corruption and extortion. In February 2018, the MEMR issued regulations to revoke past regulations related to licensing and simplify the number of exploration licences required.

A recent major corruption case has caused some legal uncertainty, in particular as to the line between bad business decisions and graft. In June 2019, the former president director of Pertamina was sentenced to eight years in prison for her involvement in alleged graft related to Pertamina’s investment in an Australian block, which ultimately resulted in losses to the company and caused state losses amounting to 568 billion rupiah. Some observers say there was a lack of legal evidence to prove graft and that the losses may simply have resulted from a bad investment. This begs the question as to the extent that bad business decisions in the oil and gas industry can be criminally charged.

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5 https://www.cipe.org/legacy/publication-docs/CIPE%20AntiCorruption%20Guidebook%200815.pdf.
IX CURRENT DEVELOPMENTS

A draft of a new oil and gas law is being prepared by the House of Representatives. This new oil and gas law is widely expected to change the oil and gas regulatory framework, with the proposed changes including the establishment of BUK Migas to replace SKK Migas, increased privileges for Pertamina in acquiring work areas, contracts and licensing mechanisms in the upstream sector, the prescribed maximum period for exploration activities, and an obligation to dedicate production to the domestic market through a safeguarding business entity established by the law.

The largest reserve in almost two decades was recently discovered, in the Sakakemang Block in South Sumatra. According to preliminary estimates, the discovery holds at least 2 trillion cubic feet of recoverable gas resources. As the discovery was made only recently, the relevant block will require further exploration and evaluation before actual production can begin, in about 10 to 15 years.

In 2018, Pertamina, through its subsidiaries, took over several expiring PSCs from PSC contractors, including the East Kalimantan and Attaka PSC from Chevron Indonesia Company, the Rokan PSC from PT Chevron Pacific Indonesia and the Mahakam PSC from Total E&P Indonesie. In 2019, the Corridor PSC in South Sumatra was granted an extension, in which ConocoPhillips (Grissik) Ltd, Talisman Corridor Ltd (Repsol), and Pertamina Hulu Energi Corridor will have the right to the Corridor PSC until 2043, with the PSC adjusted from a cost recovery PSC to a gross split PSC.

Also recently, the government announced the results of the first phase of oil and gas working area tenders for 2019. Three exploration blocks (Anambas, West Ganal and West Kaimana), and two production blocks (Selat Panjang and West Kampar) were tendered. For the second phase, three exploration blocks (Kutai, Bone and West Ganal) and one production block (West Kampar) were tendered. The third phase of oil and gas working area tenders for 2019 is now open and will be closed on 25 October 2019. For the third phase, four blocks (East Gebang, West Tanjung I, Belayan I and Cendrawasih VIII) were tendered.
Chapter 17

IRAQ

Christopher B Strong

I INTRODUCTION

Having only recently become open to foreign investment in its upstream sector after years of sanctions, the Republic of Iraq is emerging as an important area of focus for international oil companies. While currently beset by a number of challenges, including low oil prices and ISIS activity, Iraq's combination of massive existing fields in need of redevelopment combined with significant exploration upside offers unique opportunities for companies that are willing to undertake the challenges of investing there.

This chapter provides an overview of the legal regime in federal Iraq as it relates to oil and gas investments, provides a brief update on recent updates in Iraq's upstream sector, and also provides a case study of the Basrah Gas Project, a recently completed project in Iraq's midstream sector that illustrates a potential framework for foreign investment in this important aspect of Iraq's petroleum industry.

II LEGAL AND REGULATORY FRAMEWORK

i Constitutional framework

The basic legal framework for the oil and gas sector in the Republic of Iraq is set forth in the Constitution of Iraq, which was approved by the Iraqi people by referendum on 15 October 2005 and entered into force in 2006. The relevant provisions of the Constitution provide as follows.

Article 111

Oil and gas are owned by all the people of Iraq in all the regions and governorates.

Article 112

First: The federal government, with the producing governorates and regional governments, shall undertake the management of oil and gas extracted from present fields, provided that it distributes its revenues in a fair manner in proportion to the population distribution in all parts of the country, specifying an allotment for a specified period for the damaged regions that were unjustly deprived of them by the former regime, and the regions that were damaged afterwards in a way that ensures balanced development in different areas of the country, and this shall be regulated by a law.

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Second: The federal government, with the producing regional and governorate governments, shall together formulate the necessary strategic policies to develop the oil and gas wealth in a way that achieves the highest benefit to the Iraqi people using the most advanced techniques of the market principles and encouraging investment.

ii Draft oil and gas law

As referenced above, Article 112 of the Constitution of Iraq requires the enactment of a law to regulate the oil and gas sector. To date, however, no such law has been enacted.

In February 2007, an initial draft oil and gas law was approved by the Council of Ministers and later revised in April of 2007. Because of differences over the terms of the draft law, the 2007 draft law was never enacted.

A revised draft of the oil and gas law was presented to the Council of Ministers in 2011. Among its salient points are the following:

a the establishment of a Federal Oil and Gas Council (FOGC), which would act as the main body for overseeing the Iraqi petroleum sector. The membership of the FOGC would consist of:

- the relevant Deputy Prime Minister;
- the Minister of Oil;
- the Minister of Finance;
- the Minister of Planning;
- the Governor of the Central Bank of Iraq;
- a ministerial-level representative of the Kurdistan region (and any other region formed pursuant to the Constitution subsequent to the enactment of the oil and gas law);
- representatives from each producing governorate not included in a region;
- the heads of the Iraq National Oil Company and the Oil Marketing Company (SOMO) (and other relevant companies); and
- up to three experts specialised in matters relating to oil and gas, finance or economics;

b the delegation of the following responsibilities to the FOGC:

- approving petroleum industry policies, field development plans and pipeline plans;
- endorsing regulations and guidelines for the negotiating and granting of exploration, development and production contracts;
- endorsing models for exploration development and production contracts;
- approving exploration, development and production contracts;
- approving the funding entity and deciding on transfers of shares among holders of exploration, development and production contracts;
- oversight of the Iraq National Oil Company, the Ministry of Oil and relevant regional authorities; and
- setting production levels;

c the establishment of the Iraq National Oil Company, which will:

- manage, operate and develop (through its subsidiary companies) currently producing fields;
- participate in exploration, development and production operations within Iraq on behalf of the government; and
- manage and operate pipelines and export facilities;
d provision for the relevant authority in the Kurdistan region (or any other region that may be established pursuant to the Iraqi Constitution subsequent to the enactment of the oil and gas law) to participate in petroleum related matters by:

- making policy recommendations to the relevant federal authorities;
- participating with the Ministry of Oil in the procedures for licensing rounds in the region (other than for currently producing fields and discovered but undeveloped fields located near currently producing fields);
- cooperating with the Ministry of Oil in the supervision of petroleum operations within the region; and
- attending negotiations conducted by the FOGC;

e provision for the entry of exploration, development and production contracts with private companies (both Iraqi and foreign), including principles for the granting of such contracts, and topics to be included in all such contracts, including:

- establishing the principles of national control and Iraq’s ownership of all petroleum resources;
- an initial period of four years, with up to two extensions of two years each and additional periods to determine the commercial value of a discovery and evaluate discovered but undeveloped fields;
- a development period of up to 20 years from the date of approval of the development of a field;
- an obligation to develop a field development plan for each commercial discovery, submit the same for approval by the competent body (the Ministry of Oil, the Iraq National Oil Company, or the appropriate regional body) and endorsement by the FOGC;
- a requirement that the Ministry of Oil will have the exclusive right to receive and market all produced petroleum, and transport the same through pipelines;
- a requirement to give preference to the purchase of Iraqi products and services in petroleum operations;
- requirements for the employment and training of Iraqi nationals;
- a requirement to support Iraqi institutions in research and development activities relating to petroleum operations; and
- observance of international standards with respect to the protection of the environment and the prevention of pollution; and other environmental requirements. Importantly, the draft oil and gas law does not specify the form that petroleum contracts must take, and thus leaves open the possibility that production sharing contracts may be permitted in the future;

f a clear right for licence holders to transfer profits outside of Iraq (after payment of relevant taxes);

g a requirement that petroleum revenues be ‘distributed fairly among the people’, as regulated by a separate law; and

h establishment of a future fund in which a percentage of petroleum revenues will be deposited to ensure the rights of future generations.
iii Law of Private Investment in Crude Oil Refining

Another Iraqi law relevant to the oil and gas sector is the Law of Private Investment in Crude Oil Refining (Law No. 64 of 2007, as amended by Law No. 10 of 2011) (the Refining Law).

The purpose of the Refining Law is to encourage private sector investment in Iraq's refining sector, and it specifically allows the private sector to establish crude oil refineries, possess, operate and manage their facilities, and to market their products.

Under the terms of the Refining Law, all applications by private sector entities to invest in the Iraqi refining sector and enjoy the privileges established under the Law are to be submitted to the Ministry of Oil, which will form a specialised committee to review such applications. The Refining Law also allows the Ministry to 'enter into contracts of any international common form in the field of refineries' (which should allow most of the typical foreign investment structures such as BOO, BOOT, etc., to be implemented) as well as to own up to 25 per cent of the refining company.

To encourage private sector investment in the refining sector, the Refining Law offers the following incentives:

\(a\) The Ministry of Oil is obligated to supply crude oil to the refining company at a price equal to the international FOB export price for Iraqi crude less a discount of 5 per cent; provided that the discount will not be less than US$4 per barrel or more than US$8 per barrel. The discount will apply for a period of 50 years.

\(b\) The refining company is entitled to sell its products both internally in Iraq and for export and to determine the price at which its products are sold in accordance with international market prices. The Ministry of Oil will have first priority to purchase all products produced by the refinery, subject to paying international market prices.

\(c\) The refining company is entitled to establish and operate stations for the sale of gasoline and other oil products.

\(d\) Although the refining company is not entitled to own land, the Ministry of Finance is obligated to lease the land necessary for the refinery for a period of up to 40 years (extendable) and at an annual rate of rent to be agreed by the refining company and the Ministry of Finance. The lease will be exempt from the requirements of the Law of Selling and Leasing Property of the State (Law No. 32 of 1986).

\(e\) The refining company is entitled to use public facilities such as export terminals and pipelines in accordance with a contract to be signed between it and the Ministry of Oil or other relevant ministries.

\(f\) The refining company is entitled to all of the benefits stipulated in the Investment Law (No. 13 of 2006), including:

- a 10-year tax holiday from commencement of operations;
- a three-year exemption on import duties for imported assets, with a subsequent exemption for spare parts and parts required for expansions;
- the right to repatriate capital and salaries;
- the right to open and maintain offshore bank accounts;
- the right to employ non-Iraqis if the refining company is unable to employ suitably qualified Iraqi nationals (subject to a requirement in the Refinery Law that at least 75 per cent of employees must be Iraqi nationals); and
- the right to provide for international arbitration in its commercial contracts.

In addition to the incentives noted above, the Refinery Law imposes a number of requirements on companies seeking to invest in the refining sector, including the following:
all refineries must employ ‘highly advanced technology’, and heavy oil products cannot exceed 20 per cent of total production;

\( b \) the refining company must construct, operate and maintain a pipeline connection from the refinery site to the Iraqi crude oil pipeline network;

\( c \) the refining company is not entitled to trade in crude oil or in products produced by state-owned refineries;

\( d \) the refining company is responsible for ensuring the supply of electrical power and all other utilities necessary for the operation of the refinery;

\( e \) the refining company must submit periodic financial and technical reports to the Ministry of Oil in accordance with the form prepared by the Ministry of Oil and instructions issued by the Minister of Oil;

\( f \) the refining company must observe all laws and regulations relating to the environment and industrial safety; and

\( g \) as mentioned above, at least 75 per cent of the employees of the refining company must be Iraqi nationals.

iv Treaty network

Iraq is not a party to the 1958 Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention), but it is a signatory to the 1983 Riyadh Convention for Judicial Cooperation (the Riyadh Convention). Under the terms of the Riyadh Convention, judgments rendered in one contracting state may be enforced in the courts of another contracting state, subject to the exclusions set forth in the Riyadh Convention.

III LICENSING

i Types of instruments and key licence terms

The principal contracts used for the licensing of petroleum interests in Federal Iraq are the technical service contract (TSC), which is used for the redevelopment of producing fields, and the development and production service contract (DPSC), which is used for the development of discovered but undeveloped fields.

Under both TSCs and DPSCs, the contractor is remunerated on the basis of cost recovery and a per-barrel remuneration fee. This represents a key difference between the contracts used in Federal Iraq and the production sharing contracts found in other parts of the world, where the contractor is remunerated on the basis of cost recovery plus a share of ‘profit petroleum’ (generally, the portion of petroleum production remaining after the contractor has received its allocation of cost recovery petroleum). The size of the remuneration fee varies between blocks, with producing blocks generally receiving a lower fee and exploration blocks generally receiving a higher fee. The remuneration fee also varies in accordance with an ‘R-factor’, under which a ratio of the contractor’s cash receipts to its expenditures is periodically calculated, and as the ratio increases the remuneration fee decreases. Importantly, the remuneration fee does not take into account oil prices, which means that the contractor receives no upside from higher oil prices and it not exposed to downside as a result of lower prices. Its return is based solely on its ability to meet the production targets specified under the contract.

Under both TSCs and DPSCs, the contractor only becomes eligible to recover its costs and receive its remuneration fee once it has met the eligibility criteria specified in the agreement; provided that certain costs defined as ‘supplementary costs’ (which generally
include signature bonuses, costs for remediation of pre-existing environmental conditions and de-mining, and costs for certain facilities as specified in the TSC or DPSC) can be recovered more quickly. For TSCs, the eligibility criteria are satisfied either upon achieving a specified level of production over a period of 30 days or the lapse of a specified period (generally three years) after the approval of a rehabilitation plan, while for the DPSCs the eligibility criteria are similar, except that instead of achieving a specified level of production the contractor is generally required to first achieve commercial production. Under both contracts, the eligibility criteria for recovery of costs and receipt of remuneration fees provide strong incentives for the contractor to achieve production targets as rapidly as possible.

Cost recovery and the remuneration fee are payable to the contractor in crude oil or, at the contractor’s option, cash; provided that supplementary costs (as described above) are payable in cash or, at the option of the Iraqi partner to the agreement, in crude oil.

The term under both the TSC and the DPSC is generally 20 years, with an extension available in the event of any prolonged period of force majeure.

TSCs all generally provide for a plateau production target to be achieved within a specified period of time. Over the past few years it has become apparent that many of the plateau production targets that were initially contemplated in the TSCs are not practicable given the existing state of Iraq’s oil export facilities and other technical and logistical impediments. Accordingly, the Ministry has been in the process of renegotiating the TSCs to establish more realistic plateau production targets.

TSCs and DPSCs are governed by Iraqi law, with disputes generally resolved in accordance with international arbitration.

ii Contract awards
To date, awards of TSCs and DPSCs in federal Iraq have been conducted through a transparent and open public bidding process conducted by the Ministry of Oil’s Petroleum Contracts and Licensing Directorate (PCLD). Prospective bidders must pre-qualify with the PCLD before submitting a bid. Four licensing rounds have been held to date. Since June 2014, bids for a special licensing round involving the integrated development of the Nasiriya oilfield and a 300,000 barrel per day refinery have repeatedly been delayed but Iraq’s Oil Minister, Mr Allaibi, has recently called for the administration delays offering the project to be reduced so that it could be restored.

IV PRODUCTION RESTRICTIONS
Iraq is a member of OPEC and has indicated that it will begin complying with OPEC production quotas at some point in the near future, although the date upon which it will begin complying and the production quota to which it would be subject have yet to be determined. Iraq’s quota at the time of the first Gulf War (when it was officially excluded from OPEC’s quota system) was 3.8 million barrels. The effect on the TSCs and DPSCs of any future agreement by the Iraqi government to comply with OPEC production quotas is unclear.
V ASSIGNMENTS OF INTERESTS

Under the terms of the TSCs and DPSCs, companies are not entitled to assign any of their rights or obligations to any person other than a 100 per cent affiliate without the prior written consent of their Iraqi counterparty. For these purposes, the TSCs also generally provide that a direct or indirect transfer of shares or other ownership interests constitutes an assignment.

Given that the TSCs and DPSCs have all been awarded relatively recently, there has not been much history to date of the government’s approach to transfers of interests. Anecdotal evidence relating to the few examples where interests under TSCs or DPSCs have been transferred indicate a willingness on the part of the government to allow transfers, particularly where the proposed transferee is technically and financially qualified, but the government nevertheless retains broad discretion in choosing whether to consent to transfers of interests and in setting the conditions for its consent.

VI TAX

Foreign oil companies operating in Iraq are taxed in accordance with the Law of Income Tax on Foreign Oil Companies Working in Iraq (Law No. 19 of 2010) (the Oil Tax Law) and its accompanying regulations (Regulation No. 5 of 2011) (the Tax Regulations).

The Oil Tax Law provides that income earned in Iraq from contracts signed with foreign oil companies and their subsidiaries, branches and subcontractors working in Iraq in the field of oil and gas extraction, production and related industries will be taxed at a rate of 35 per cent. The Tax Regulations go on to clarify that the types of contracts on which the 35 per cent tax rate is applicable include:

- contracts for the exploration, development and production of exploration blocks and oil and gas fields (i.e., TSCs);
- seismic survey contracts;
- contracts for the drilling of wells;
- contracts for the reclamation of wells;
- contracts for well services including casing, cementing, stimulation, electrical logging and completion;
- contracts for surface installations of oil and gas extraction and production operations;
- contracts for water injection facilities;
- contracts for flow pipes;
- contracts for gas treatment facilities;
- contracts for cathodic protection;
- contracts for engineering surveys and quality control;
- contracts for the drilling of water wells; and
- other activities relating to the extraction process through the point of export.

Pursuant to the Tax Regulations, the Ministry of Oil is required to deduct 35 per cent from the revenues due to foreign oil companies, and the foreign oil companies are required to deduct 7 per cent of amounts payable to their subcontractors. All amounts so deducted are to be held on deposit by the State Commission of Taxes and reconciled during the final taxation process.

For matters not specified in the Oil Tax Law or the Tax Regulations, the Law on Income Taxation (No. 113 of 1982) will apply.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Iraq’s principal legislation in relation to environmental issues is the Law on Protection and Improvement of the Environment (Law No. 27 of 2009) (the Environmental Law). The Environmental Law sets forth broad requirements relating to the prevention of pollution and the management of hazardous waste. It also imposes the following specific requirements on entities involved in the exploration and extraction of petroleum and natural gas:

- to take necessary measures to limit the dangers and risks resulting from petroleum operations;
- to take necessary measures to protect earth, air, water and underground reservoirs from pollution and destruction;
- to take necessary precautions to dispose of produced salt water through safe environmental methods;
- to prevent spills of oil and refrain from injecting oil into subsurface areas that are used for human and agricultural purposes; and
- to provide the Environmental Ministry with information about the causes of any fires, explosions, breakdowns, accidents and leakage of crude oil and gas from wells and pipelines.

In addition to the requirements of the Environmental Law, the TSCs and DPSCs contain provisions addressing environmental issues in petroleum operations, including the following:

- a requirement to conduct petroleum operations with ‘due regard for the protection of the environment and the conservation of natural resources’ and to adopt best international petroleum industry practices in conducting and monitoring its operations and take all necessary steps to prevent environmental damage, prevent harm to livelihood or quality of life in surrounding communities;
- a requirement to carry out an environmental study to determine existing environmental conditions within the contract area to serve as a baseline for determining any environmental damage that may be caused by the contractor;
- a requirement to carry out an environmental impact study to establish the likely effect on the environment from conducting petroleum operations and to recommend measures for mitigating the environmental impact of petroleum operations;
- prior to conducting drilling activities, to prepare a contingency plan for dealing with spills, blowouts, fires, accidents and emergencies resulting from petroleum operations;
- upon expiry or termination of the agreement, to remove all equipment and installations from the contract area pursuant to an agreed abandonment plan; and
- around the middle of the term of the agreement, to prepare a plan relating to site restoration, including a decommissioning plan.

Except in the case of gross negligence or wilful misconduct, all costs incurred in relation to protection of the environment or in remediating damage to the environment are cost recoverable. In addition, costs incurred in relation to remediating preexisting environmental conditions and approved in advance are also recoverable as supplementary costs.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Foreign investors in the upstream oil and gas sector can invest through a foreign entity with an Iraqi branch. Establishment of a local entity is not required.

Under the terms of the PSCs and DPSCs, the entity designated as the ‘lead contractor’ is additionally required to establish and maintain an office in Baghdad.

ii Anti-corruption

The main legislation in Iraq with respect to anti-corruption matters is contained in the Iraqi Penal Code. Article 310 of the Iraqi Penal Code provides:

Any person who gives, offers, or promises a public official or agent [a gift, benefit, honour or promise thereof to carry out any duty of his employment, or to refrain from doing so] is considered to be offering a bribe.

Any person who mediates for a person who offers or accepts a bribe in order to offer, seek, accept, receive or promise such bribe, is considered to be an intermediary.

The person who offers a bribe as well as the intermediary is punishable by the penalty prescribed by law for a person who accepts such bribes.

Article 19(2) of the Iraqi Penal Code defines a ‘public official’ as ‘any official, employee or worker who is entrusted with a public task in the service of the government or its official or semi-official agencies belonging to it or placed under its control’.

A person convicted of an offence under Article 310 is punishable by imprisonment for a term of up to 10 years plus a fine of up to 500 Iraqi dinars.

IX CURRENT DEVELOPMENTS

i Pending contract renegotiation

The recent significant decline in oil prices, combined with a need for Iraq to devote a significant portion of its budget to combat militants from the Islamic State, has created a significant strain on Iraq’s budget. As a result, as has been widely reported in the industry press, officials from the Ministry of Oil have contacted their IOC partners and asked them to propose revised terms to their upstream agreements that would result in greater cash flow to Iraq over the short to medium term. Among the proposals that have been floated to achieve this are (1) deferral of cost reimbursement, (2) linking remuneration fees to oil prices rather than calculating them as a fixed fee per barrel, (3) linking remuneration fees to cost reductions, and (4) reducing the cap on the percentage of revenues that can be used to pay cost reimbursement and remuneration fees to the IOCs, which currently is set at 50 per cent under most of the upstream agreements.

Other topics that may be discussed include adjustments to plateaus and contract durations, as well as increasing the participation levels of state-run Iraqi companies that have generally been decreased during previous rounds of renegotiations.

The renegotiation process has been delayed, and some of the previous urgency may have dissipated given the stabilisation of oil prices, but reports indicate that the Ministry of Oil would still like to engage with its IOC partners on these issues.
One of the more notable recent projects in Iraq’s upstream sector is the Basrah Gas Project, which commenced operations in May 2013. Set forth below is a case study of the project:

**Strategic background**

The principal goal of the Basrah Gas Project is to capture and utilise associated gas produced from three major fields in southern Iraq – Rumaila, Zubair and West Qurna (Phase I). Because of a lack of processing and transportation infrastructure, a significant portion of the associated gas produced from these fields (over 750 million cubic feet per day on average) has historically been flared. This not only represents a significant waste of a valuable resource, but also has a substantial negative impact on the environment. This adverse environmental impact is exacerbated by the fact that, because of the poor state of repair of the separators in the three fields, crude oil and other liquids are included in the flared gas stream, increasing the carbon content and resulting in the ‘black flares’ that are an all too common sight in the Basrah region.

Through a combination of rehabilitating the existing gas processing and transportation infrastructure and investing in new infrastructure, the Basrah Gas Project will reduce, and eventually eliminate, the flaring of associated gas from the three major fields. This will have the benefit of providing a source of dry gas for power generation and industrial development, capturing LPG and condensate (which will enable Iraq to become a net exporter of LPG), reducing costs currently incurred by the Iraqi government to import fuel oil for power generation and LPG, and reducing air pollution and carbon emissions.

**Legal structure**

Basrah Gas Company (the legal entity through which the Basrah Gas Project is being implemented) is organised as a mixed limited liability company under the Iraqi Companies Law No. 21 of 1997. A mixed limited liability company is a unique type of entity under Iraqi law that allows both public and private sector entities to be shareholders. Although the provisions allowing for mixed limited liability companies have been part of Iraqi law for a number of years, Basrah Gas Company is the first mixed limited liability that has been formed.

The shareholders in Basrah Gas Company are South Gas Company (a state-owned entity under the direction of the Ministry of Oil), which holds 51 per cent of the equity interests, and subsidiaries of Shell and Mitsubishi, which own 44 per cent and 5 per cent respectively. Management of Basrah Gas Company is overseen by a higher management committee with members appointed by each of the shareholders. Under Iraqi law, limited liability companies do have boards of directors, but the shareholders in Basrah Gas Company were able to create a body with analogous powers through a contractual agreement as reflected in a shareholders’ agreement. Management positions are filled with appointees from South Gas Company and Shell, with an intention that as time goes on expatriate managers will gradually be phased out in favour of Iraqi nationals.

Following formation of Basrah Gas Company, and immediately prior to its commencement of operations, South Gas Company contributed existing gas processing and transportation infrastructure to Basrah Gas Company at an agreed valuation (as determined by an independent appraiser). The contribution of assets excluded rights to the underlying real estate, which was instead leased to Basrah Gas Company under a long-term agreement.

The contribution of assets was deemed to constitute a shareholder loan from South Gas Company to Basrah Gas Company in an amount equal to the appraised value of the assets.
Going forward, Shell and Mitsubishi will be obligated to make capital contributions (in the form of shareholder loans) to Basrah Gas Company until their combined contributions are equivalent in value to the assets contributed by South Gas Company. After that point, all shareholders will contribute capital sufficient to fund Basrah Gas Company’s capital expenditure programme on a pro rata basis in accordance with their shareholding percentages. All capital contributions will be in accordance with a work programme and budget that will be jointly developed and agreed by the shareholders in the manner contemplated by the Basrah Gas Company shareholders’ agreement.

**Commercial structure**

Under the TSCs for the Rumaila, Zubair and West Qurna (Phase I) fields, the operators are required to deliver all associated gas that is not used for petroleum operations to South Oil Company, a state-owned entity under the direction of the Ministry of Oil. South Oil Company will transfer the associated gas to South Gas Company, which will in turn sell the gas to Basrah Gas Company under a long-term raw gas supply agreement. Basrah Gas Company will then process the gas and sell the resulting dry (processed) gas, LPG and condensate back to South Gas Company, which will then on-sell the products in the domestic market. Once LPG production in Iraq is sufficient to satisfy domestic demand, Basrah Gas Company will also be able to sell excess LPG for export. As the Oil Marketing Company of the Republic of Iraq (SOMO) has the exclusive legal right to export petroleum products from Iraq, Basrah Gas Company and SOMO have entered into an export agency agreement under which SOMO will act as Basrah Gas Company’s export agent. The agreement also provides to the establishment of a joint marketing committee between Basrah Gas Company and SOMO to determine marketing strategy and act, in effect, as Basrah Gas Company’s export marketing department.

Once gas production in Iraq is sufficient to satisfy domestic demand, Basrah Gas Company will also have the right (subject to certain conditions) to develop the first project to export LNG from Iraq. As with LPG, the LNG will be sold through an export agency arrangement with SOMO, and Shell has the right to purchase all of the LNG produced by the project’s first LNG train.

**Challenges**

As a first-of-its-kind project, the Basrah Gas Project faced a number of challenges. Although the mixed limited liability format is recognised under Iraqi law, such a company had never been formed before. The transfer of state-owned assets into a company with private sector ownership also presented new issues, as did the lease of state-owned real estate and the capitalisation of Basrah Gas Company via shareholder loans. In fact, the list of ‘firsts’ that the project presented from an Iraqi perspective is so extensive that it would be beyond the scope of this chapter to discuss them all. But through patience, persistence and cooperation, the participants in the project were able to work through the myriad issues and develop a legal and commercial framework that should form the basis for lasting success. Importantly, the Basrah Gas Project should also serve as a template for other projects involving Iraq, particularly those that are contemplated to be structured as partnerships between state-owned entities and foreign investment and those that contemplate the refurbishment and expansion of state-owned assets.
I IRAQI KURDISTAN

Florian Amereller and Dahlia Zamela

I INTRODUCTION

The Republic of Iraq, including the Kurdistan Region of Iraq (KRI), is a country vested with many easily exploitable oilfields. The exploration and production of oil in Iraq started as early as the 1920s. The Iraqi oil sector was fully nationalised in 1975. After several years of war and sanctions, Iraq, against the backdrop of its post-conflict setting, besieged by competing political, ethnic and sectarian factions, corruption and turmoil, aims to replace the former state monopoly on oil and gas with private development.

The KRI has been particularly successful in this regard. Starting oil and gas activities only in 2006, the Kurdistan regional government (KRG) concluded more than 50 production-sharing contracts (PSCs) with international oil companies (IOCs). Initially the contracting partners were minor oil companies such as Gulf Keystone, Genel and Western Zagros. Gulf Keystone discovered the giant Shaikhan field with 14 billion barrels of oil in place (subsequently adjusted downwards). It was one of the world’s largest onshore discoveries in more than 20 years. In 2012, ExxonMobil pioneered as the first major IOC, followed by Chevron, Total and Gazprom.

The Kurdistan Region Ministry of Natural Resources (MNR) estimates the reserves at 45 billion barrels of oil and at 25 trillion cubic feet (tcf) of proven gas reserves and up to 198 tcf of largely unproven gas. If the KRI were an independent country, the amount of oil and gas reserves would place it among the top 10 oil-rich countries in the world. However, the region is still an integral part of the Republic of Iraq even though it enjoys semi-autonomy.

Both the KRG and the central government in Baghdad remain at odds over the authority to administer and dispose of oil being produced in the KRI at a current estimated production level of 426,000 barrels per day (bpd). In the course of these quarrels, the central government has repeatedly withheld the payments of federal budget portions allocated to the KRI. In turn, the KRG continued and expanded its independent oil exports to Turkey. The low world market oil prices and the Kurdish peshmerga’s and Iraqi army forces’ fight against the terrorist group ISIS created a severe financial crisis in the KRI.

In 2016, owing to the strained financial situation of the KRI, the central government and the KRG again began to jointly export crude oil from the Kirkuk fields to Ceyhan in Turkey. The parties continued negotiations to finally reach a comprehensive revenue-sharing deal involving the entire oil and gas reserves of Iraq but with little success.

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In 2017, and after three years of ISIS controlling huge swathes of land in northern Iraq, Mosul, the last major stronghold of ISIS in Iraq was liberated, and the existence of ISIS in northern Iraq has been substantially reduced. However, this has unfortunately not resulted in the desired stability to the region and Baghdad and the KRI remain at odds over the regions’ oil reserves and the rights of the KRI to export crude oil independently of Baghdad and SOMO, the Iraqi oil marketing organisation.

Following a very rocky 2016, where the KRI was behind on payments to major IOCs, and involved in major military operations to liberate Mosul, in 2017 the KRI took major steps to remedy the situation and bolster confidence in the KRI from the IOCs and the international community. Most importantly, settlement agreements were reached with several IOCs. Further, agreements were entered into with Russian Rosneft, despite objections from Baghdad, to manage and develop the Turkey pipeline in addition to agreements for cooperation in the entire hydrocarbons production chain including exploration and development of five blocks, production and logistics. Rosneft further agreed to finance Kurdish crude oil. A new deal was signed in early 2018 focusing on developing the gas sector in the KRI, including a new gas pipeline. Furthermore, Rosneft will reportedly start geological explorations in the KRI later in 2019.

On the political front, the KRI, after its leading role in liberating both Kirkuk and Mosul and its apparent successes in the oil and gas sector, held a referendum for independence on 25 September 2017. The positive outcome was at the very least expected to give the KRI additional footing and leverage in any future negotiations with Baghdad regarding oil and gas in the Kurdish-controlled regions of northern Iraq, especially given the supportive stance of Kirkuk. However, soon after the referendum, Iraqi forces retook Kirkuk and control of the oilfields from the Kurds, cutting the KRI’s revenues nearly by half. Losing control over the oilfields meant reliance on Baghdad for income once again.

Exports from Kirkuk were halted after the post-referendum military offensive by the central Iraq forces, which then diverted outputs to local refineries. On 16 November 2018, exports from Kirkuk to the Ceyhan pipeline resumed. The central government exported up to 105,000bpd in June 2019 from Kirkuk, most of which was transported via Ceyhan. There have been ongoing discussions for months regarding the security and military situation in Kirkuk, and although there has been some cooperation over the past year, the Kirkuk issue still remains to be resolved. Adding to the tensions is the KRG’s failure to contribute 250,000bpd to the central government in exchange for its share of the federal budget as agreed in the 2019 budget. As of July 2019, there had been attempts by a faction of the Iraqi parliament to amend the 2019 budget and cut transfers to the KRG if the latter does not deliver the required amount of oil. However, this garnered few votes, and the KRG will receive a limited budget allocation regardless of whether it abides by its obligation or not, as the 2019 budget law appears to be more lenient than previous annual budgets in this regard.

In 2012, the central government filed a case against the KRG challenging the latter’s independent oil exports. The case was continuously postponed owing to a procedural loophole that prevented the court from hearing the case without the attendance of a KRG representative. This finally changed in April 2018 when the KRG attended the court. Since then, proceedings have been slow and the ruling constantly delayed, with the most recent delay owing to a missing signature from the Iraqi Prime Minister Adil Abd al-Mahdi on revising filings submitted to court.

Amidst internal conflict between the different Kurdish political parties resulting from many factors, including the independence referendum, former KRI president Masoud
Barzani’s resignation on 29 October 2017, the financial difficulties and the disputes with central government amongst others, the KRI held its parliamentary elections in September 2018. No single party won the majority of the Kurdish parliamentary seats. At the same time Mr Barham Salih was elected the president of Iraq. More recently, the Kurdistan Parliament elected former KRI Prime Pinister and Masoud Barzani’s nephew, Nechirvan Barzani, as President of the KRI on 28 May 2019, and Masoud Barzani’s son, Masrour Barzani, as Prime Minister on 10 June 2019. Both have expressed their determination in helping to improve relations between the KRG and central government.

II LEGAL AND REGULATORY FRAMEWORK

Iraq’s legal framework for the petroleum industry is quite ambiguous. Pursuant to the Iraqi Constitution, ‘oil and gas are owned by all the people of Iraq in all the regions and governorates’. However, the exploration and production of oil and gas are not governed by the Iraqi Constitution. It only states that ‘the central government, with the producing governorates and regional governments, shall undertake the management of oil and gas extracted from present fields, provided that it distributes its revenues in a fair manner in proportion to the population distribution in all parts of the country . . . and this shall be regulated by a law.’

The Iraqi Constitution only refers to ‘present fields’ where the management of present fields falls under the shared jurisdiction, while the management of other oil and gas resources that are not ‘present fields’ are not expressly addressed in the Constitution. Nonetheless, the term ‘present fields’ does not reflect common concepts of the oil industry such as ‘proven – probable – possible’, ‘developed – undeveloped’ or ‘producing – non-producing’. That said, the KRG maintains that present fields within the meaning of the Iraqi Constitution refers only to the oil and gas fields that were producing at the time of enactment of the Iraqi Constitution in 2005. All other oil and gas resources (i.e., fields not producing or even not discovered in 2005) are not encompassed. The KRG takes the position that non-producing fields (as of August 2005) do not fall within the shared jurisdiction of the central government and the KRG, and, therefore, the KRG has exclusive jurisdiction over such fields. Hence, the KRG regards itself as the competent authority to regulate all oil and gas resources in the Kurdistan region other than ‘present fields’. The central government in Baghdad rebuts this interpretation of the Iraqi Constitution and believes that the KRG lacks the requisite constitutional authority to sign contracts with foreign oil companies, which it deems illegal.

Pursuant to Article 112(1) of the Constitution, the foregoing varying interpretations should have been regulated by a law creating a comprehensive and fair framework for the management of the Iraqi oil and gas sector, including the rights and competencies of the governorates and regions to have an active role in the management and a share of the revenues. For years, the KRG and the central government failed to agree on a unified federal oil and gas law in implementation of the Iraqi Constitution. Finally, in 2018, a new Iraqi National Oil Company Law No. 4/2018 (the INOC Law) was passed by the Iraqi parliament and came into force in April 2018. While the INOC Law contains some provisions that appear to implement some of the requirements of the Constitution and to liberate the oil and gas sector, the INOC Law is far from a federal oil and gas law as envisioned by the constitution.

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as it does not address in any detail the management and cooperation between the central government and the KRG with respect to oil and gas from present or future fields. The INOC Law was immediately challenged on the basis of the constitutionality of some of its provisions. In January 2019, the Federal Supreme Court found that a number of the INOC Law provisions were unconstitutional, effectively rendering the INOC Law impossible to implement without first amending or replacing the unconstitutional Articles.

A decision of the Federal Supreme Court is also pending in the proceedings initiated by the central government in 2012 challenging the KRG’s right to independently export crude oil from the KRI. In 2014, the court refused to grant the Federal Ministry of Oil an injunction against the KRG prohibiting it from exporting crude oil independently on the basis ‘that [granting such an injunction] would give an impression of a premature decision on the subject matter of the proceedings and the decision that shall be issued by the court’ which would contravene the judicial “context/norms”. The final decision of the Federal Supreme Court on the matter, whether positive or negative will have far reaching implications on the oil and gas landscape of the KRI and Iraq as a whole.

i Domestic oil and gas legislation

The Iraqi Constitution gives the regions the right to legislate on any matters that do not fall within the exclusive jurisdiction of the central government4 and, pursuant to the Kurdistan National Council (the predecessor to the current Kurdistan parliament) Decision No. 11/1992, federal laws passed after 1992 are not applicable in the KRI unless specifically adopted pursuant to a KRI law. The Constitution further provides that where a conflict exists between a federal law and a regional law, the regional law shall prevail.5

Premised on the foregoing, in 2007 the KRI legislator passed its own Kurdistan Oil and Gas Law – No. 22/2007 (KOGL). The KOGL applies to all petroleum operations in the KRI. No federal legislation, and no agreement, contract, memorandum of understanding or other federal instrument that relates to petroleum operations, applies in the KRI except with the express agreement of the relevant authority of the KRG.6 Hence, the federal Iraqi legislation and regulations with respect to petroleum operations is not applied in the KRI.

The MNR oversees all oil and gas matters in the KRI. The Minister of Natural Resources may license petroleum operations (i.e., activities including prospecting, exploration for, development, production, marketing, transportation, refining, storage, sale or export of petroleum; or construction, installation or operation of any structures, facilities or installations for the transportation, refining, storage, and export of petroleum, or decommissioning or removal of any such structure, facility or installation7) to third parties8 after approval of the Regional Council for the Oil and Gas Affairs of the Kurdistan Region – Iraq (the Regional Council) (which consists of all relevant ministers of the KRG’s cabinet9 identified in Section II.ii). The MNR shall encourage public and private sector investment in petroleum operations.10

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4 Article 115 Iraqi Constitution.
5 Article 121(2) Iraqi Constitution.
6 Article 2 KOGL.
7 Article 1 No. 18 KOGL.
8 Article 3(4) KOGL.
9 Article 4 KOGL.
10 Article 9(1) KOGL.
The central government in Baghdad asserts that the KOGL, as well as all petroleum contracts entered into by the KRG, including PSCs as well as the recent Rosneft agreements, are unconstitutional and, therefore, invalid. Based on this position, the central government has in the past repeatedly refused to pay the KRG the full share of the oil revenues generated by SOMO and stopped payments to the KRG altogether in April 2014. Negotiations to finally settle this ongoing dispute continue.

In April 2013, the KRI adopted the ‘Law of identifying and obtaining financial dues to the Kurdistan Region – Iraq from federal revenue’ (the Financial Rights Law). The Financial Rights Law grants the KRG the right to independently export crude oil produced in the KRI if the central government fails to pay the KRG its share of revenues (including oil revenues), budget items, other national allocations and reparations. However, the central government denounces independent Kurdish oil export as ‘smuggling’. Prior to the enactment of the INOC Law, the central government took the view, based on its interpretation of the Iraqi Constitution and existing federal legislation, that SOMO has the sole authority to sell hydrocarbons internationally and all oil proceeds must be deposited with the Development Fund of Iraq (DFI) established pursuant to United Nations Security Council Resolutions (UNSCR), including UNSCR No. 1483 and in accordance with Section 5(1) of the Financial Management Law (CPA Order 95). The DFI was originally administered by the CPA but has since transferred to the federal Minister of Finance, reporting to the Council of Ministers, which shall take advice from the governor of the Central Bank.11 Article 3 of the INOC law, which permitted the INOC to sell hydrocarbons and to remit profits to the state treasury, not the DFI, has been found to be among the provisions of the INOC Law that the Supreme Court has held to be unconstitutional. Furthermore, based on the 1992 KRG Decree and the fact that oil and gas management and revenues are not captured by the exclusive authorities of the central government as provided in the Constitution, the KRI does not recognise the INOC Law as applicable to the KRI.

In the meantime and notwithstanding the constitutionality or lack thereof of the INOC Law, the central government had initiated several legal proceedings prior to the enactment of the INOC Law against entities involved in the independent export and sale of oil produced in the KRI, including the government of Turkey and its state-owned pipeline operator BOTAS, and several shipping companies. These actions by the central government have severely raised the risk assessments by many players in the market and scuttled many other intended oil sales by the KRG.

Based on the foregoing and the KRG’s continued autonomous sales of hydrocarbons despite objections from the central government, the KRI’s parliament passed the Kurdistan Oil and Gas Fund Law No. 2/2015 (KOGFL) pursuant to the KOGL. The KOGFL provides for the establishment of a monetary fund (the KOG Fund) to be managed by a board appointed by the KRG Council of Ministers after an absolute majority approval of the parliament.12 All proceeds from any hydrocarbon activity in the KRI or related to that activity, including allocations from the federal budget that are directly attributable to hydrocarbons, are to be deposited with the KOG Fund. Monies accounted for in the KOG Fund are to be remitted to the KRG Ministry of Finance to be spent in accordance with the KRG Budget. In addition, under the KOGFL monies in the fund shall be distributed according to the KOGL and with

11 Section 5(4)(a) CPA 95.
12 Article 15 KOGL.
specific allocations to a ‘future generation fund’ to be established, to the KRG budget, the social security fund, the agricultural infrastructure fund and the environment fund, as well as a US$2 per barrel allocation for each province from which the revenues were derived.

ii Regulation
The regulatory agencies competent for overseeing upstream oil and gas activities in the Kurdistan region are:

a the Iraqi Kurdistan parliament: the Kurdish parliament is the legislative body of the KRI and passes its laws;
b the KRG: the KRG governs the KRI in accordance with the laws enacted by the Kurdistan parliament;
c the Regional Council: the Regional Council consists of the Prime Minister, the Deputy Prime Minister, the Minister of Natural Resources, the Minister of Finance and Economy and the Planning Minister; it mainly formulates the general principles of petroleum policy, prospect planning and field development and approves petroleum contracts; and
d the Ministry of Natural Resources of the Kurdistan Region: the MNR oversees and regulates all petroleum operations in the KRI and it negotiates and signs PSCs on behalf of the KRG jointly with the Prime Minister representing the Regional Council.

Other agencies and ministries such as the Social Security Directorate, the Residency Directorate and the Ministry of Agriculture and Water and Irrigation have regulatory oversight for their areas of competence that fall within the activities of IOCs operating in the KRI.

iii Treaties
Pursuant to the Iraqi Constitution, the central government in Baghdad has the sole authority to sign and ratify international treaties and agreements. Iraq has signed several investment and other bilateral agreements with India, Iran, Japan, Jordan, Kuwait, Mauritania, South Korea, Sri Lanka, Syria, Tunisia, Turkey, the United Kingdom, Vietnam and Yemen, among others, some of which have not yet come into force as they are pending ratification by the Iraqi Council of Representatives. In addition, Iraq has entered into bilateral free trade agreements with the United Arab Emirates, Oman, Qatar, Algeria, Egypt, Jordan, Lebanon, Syria, Tunisia, Yemen and Sudan. In 2010, Iraq concluded bilateral investment treaties with France, Germany, and Italy. The bilateral investment treaties with France and Germany were ratified by the Iraqi Council of Representatives in 2012. As far as we are aware, the treaty with Italy has not yet been ratified.

On 11 July 2005, Iraq and the United States penned a Trade and Investment Framework Agreement. The Iraqi government ratified the agreement in December 2012. The aim of this agreement is to promote and facilitate investment and trade between the two countries. At present, the United States does not have a bilateral investment treaty with Iraq.

With regard to judicial cooperation and dispute resolution, Iraq, including the KRI, is a signatory state of the Riyadh Arab Agreement for Judicial Cooperation of 1983 (the Riyadh

13 Article 4 KOGL.
14 Article 24(1) KOGL.
15 Article 6(1) KOGL.
16 Article 107(1) Iraqi Constitution.
Convention). According to the Riyadh Convention, each contracting party shall recognise the judgments made by the courts of any other contracting party in civil cases having the force of res judicata and shall enforce them in its territory. Nonetheless, judgments made against the government or against any of its employees in respect of acts undertaken in the course of duty or exclusively on account thereof are exempted. The same applies to awards of arbitrators.

In December 2012, the website of the Iraqi Council of Representatives announced that the Council of Representatives had ratified the Convention on the Settlement of Investment Disputes between States and Nationals of Other States (the ICSID Convention). The ICSID Convention entered into force in Iraq on 17 December 2015.

On 6 February 2018, Iraq officially voted in favour of accession to the 1958 New York Convention, which applies to the recognition and enforcement of foreign arbitral awards. However, it has yet to be approved by the Iraqi parliament.

III LICENSING

To date, the KRG has signed more than 50 PSCs with IOCs. Not only did the region until very recently offer security and stability (and remarkably continues to, post ISIS and the subsequent economic crisis), the terms and conditions of the PSCs are more favourable to private investors than the technical services contracts (TSCs) and development and production services contracts (DPSCs) signed by the Federal Iraqi Ministry of Oil.

The MNR has the discretion over whether to invite applicants for licensing or to award licences based on direct negotiation. In all cases, an applicant or invitee must demonstrate technical and financial capability. It also needs to have a record of compliance with the principles of good corporate citizenship, and a commitment to the Ten Principles of the United Nations Global Compact.

Key features of the PSC are to be negotiated with the MNR based on the Model PSC published by the KRG, which includes that:

a a signature bonus and a capacity-building bonus are payable by the contractor once the PSC becomes effective;
b the KRG has the right to participate in the PSC through one of its public companies with a stake of up to 25 per cent after commercial discovery. The contracting partner is usually a consortium consisting of an IOC and a carried Kurdish national company with an undivided interest of between 20 and 25 per cent in the PSC. The Kurdish public company may, at its discretion, assign part or all of its government interest to a third party.

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17 Article 25(b) Riyadh Convention.
18 Article 25(c) Riyadh Convention.
19 Article 37 Riyadh Convention.
20 Article 26 KOGL.
21 Article 24 KOGL.
22 The Model PSC is available at www.krg.org/pdf/3_krg_model_psc.pdf.
23 Article 32.1 Model PSC.
24 Article 32.2 Model PSC.
25 Article 4.1 Model PSC.
26 Article 4.3 Model PSC.
the term of the PSC varies in accordance with advancement. The exploration period lasts for five years (comprising an initial sub-period of three years and a second sub-period of two years) and may be extended for a further two years.\textsuperscript{27} Upon commercial discovery, the development period extends to 20 years with two possible extension periods of five years each;\textsuperscript{28}

d preference is to be given by the IOC to local employment,\textsuperscript{29} subcontractors\textsuperscript{30} and materials;

e capacity building of local employment including training, funding, education and secondment of government employees is required. All reasonable training costs for Iraqi personnel are recoverable petroleum costs;\textsuperscript{31}

f during the exploration period, an annual surface rent of US$10 per square kilometre is payable. However, this exploration rental is, as it constitutes petroleum costs, recoverable.\textsuperscript{32} Twenty-five per cent of the initial contract area, excluding production areas, shall be relinquished at the end of the initial term next to an additional 25 per cent of the remaining contract area, excluding production areas, at the end of each extension period;\textsuperscript{33}

g in the event of a commercial discovery, a production bonus is payable\textsuperscript{34} in addition to a recurring royalty (i.e., a portion of petroleum produced).\textsuperscript{35} Usually, the royalty rate for export crude oil and natural gas is set at 10 per cent;

h once commercial production commences, the contractor is entitled to recover all petroleum costs (e.g., production costs, exploration costs, development costs and decommissioning costs) incurred from the hydrocarbons produced.\textsuperscript{36} The remaining ‘profit petroleum’ is split between the KRG (through its public company) and the contractor pursuant to the quotas stipulated in the PSC;\textsuperscript{37} and

i during the exploration period, the contractor may terminate the PSC at the end of each contract year.\textsuperscript{38} Once the development period has been entered into, the contractor has the right to terminate the PSC at any time.\textsuperscript{39}

Unlike the TSCs and DPSCs offered by the central Iraqi Ministry of Oil, the PSC provides the contractor with a share in the petroleum discovered and, therefore, an interest in the value of the petroleum produced. PSCs concluded by the KRG have not been approved by the central Iraqi Ministry of Oil and are disputed by the central government in Baghdad.

\textsuperscript{27} Article 6.2 Model PSC.
\textsuperscript{28} Article 6.10 and 6.12 Model PSC.
\textsuperscript{29} Article 23.1 Model PSC.
\textsuperscript{30} Article 22.2 Model PSC.
\textsuperscript{31} Article 23.7 Model PSC.
\textsuperscript{32} Article 6.3 Model PSC.
\textsuperscript{33} Article 7.1 Model PSC.
\textsuperscript{34} Article 32.3 and 32.4 Model PSC.
\textsuperscript{35} Article 24.1 Model PSC.
\textsuperscript{36} Article 25.3 and 25.4 Model PSC.
\textsuperscript{37} Article 26 Model PSC.
\textsuperscript{38} Article 45.3 and 7.4 Model PSC.
\textsuperscript{39} Article 45.4 Model PSC.
IV PRODUCTION RESTRICTIONS

At present, the MNR does not impose any restrictions on the exploration, development and production of hydrocarbons (cost and profit oil) in the KRI. As per the PSC, the contractor shall be entitled to receive and export freely any available petroleum (cost and profit oil) to which it is entitled under the agreement.

Through the PSC, the KRG reserves oil for local markets. Upon written request of the MNR, any amounts of crude oil produced that the KRG deems necessary to meet the KRI’s internal consumption requirements must be sold and transferred to the KRG at the international market price. All contractors active in the KRI must be treated equally in this regard.40

With the Financial Rights Law (mentioned in Section II), the KRI lawmaker has again confirmed the right to export crude oil independently of the central government if and to the extent the latter fails to pay the KRG its share of oil revenues and exploration costs.

The central government in Baghdad strongly objects to all such efforts by the KRI to explore and produce crude oil independently of the Federal Ministry of Oil in Baghdad.

Moreover, there are still severe practical limitations on the export of oil produced in the KRI. Although the pipeline capacity has been greatly increased and should nominally be sufficient to transport the current production output, a steady flow of export oil is not guaranteed, as the pipelines are often subject to sabotage or illegal drainage.

V ASSIGNMENTS OF INTERESTS

The KOGL provides that the relevant contract relating to petroleum operations shall specify the rights of the MNR to approve, or be notified of any assignment (in any form, whether by transfer, conveyance novation, merger, etc.) and changes in control of any contracting entity.41

In practice, and based on the Model PSC published by the MNR, PSCs normally give the KRG the right to approve any assignment, whether to an affiliate, another contracting entity or to a third party. In the case of a transfer or assignment to a third party, however, the contractor must present reasonable evidence of the assignee’s technical and financial capability.42 This requirement is not applicable to an assignment to an affiliate or to another contracting entity.

Neither the KOGL nor the Model PSC provide for a right of first refusal or any other pre-emptive rights of the KRG.

The change of control provisions contained in the Model PSC apply to any direct or indirect change of control of a contracting entity, in which the market value of such entity’s participating interest in this contract represents more than 75 per cent of the aggregate market value of the assets of such entity and its affiliates that are subject to the change in control.43

40 Article 16.15 Model PSC.
41 Article 30 KOGL.
42 Article 39.2 Model PSC.
43 Article 39.6 Model PSC.
An entity that is subject to a change of control as defined above must obtain the prior written consent of the KRG. This consent is not required if the change of control is to an affiliate or another contracting entity. Under the PSC it is not required to provide evidence of the new controlling entity’s financial or technical capability.

Typically, the KRG does not expect nor does it receive any consideration as a condition to granting approvals for an assignment or a change of control. On the contrary, the Model PSC specifically provides that any assignment or change of control ‘will not give rise to any tax, imposition or payment whatsoever in the Kurdistan Region, whether currently existing or which may become applicable in future’.44

The Model PSC provides that an assignee must enter into an agreement whereby the assignee undertakes to be bound by the terms of the PSC in the then-current form.

VI TAX45

According to the KOGL all persons associated with ‘petroleum operations’ are liable for all applicable taxes of the KRG, including: (1) surface tax; (2) personal income tax; (3) corporate income tax; (4) customs duties and other similar taxes; (5) windfall profits or additional profits tax; and (6) any other tax, levy or charge expressly included in its petroleum contract.46

Based on the above, upstream oil and gas operations would be subject to the tax laws and regulations applicable to all commercial activities in the KRI, in particular the Federal Income Tax Law No. 113/1982 as adopted and amended in Kurdistan pursuant to the KRG Law No. 26/2007 as amended from time to time (KRG ITL). According to the KRG ITL, all commercial activities are subject to a flat corporate income tax rate of 15 per cent on profits.

The current KOGL does not contain any tax exemption for IOCs and other upstream operators active in the KRI. It does, however, provide that a petroleum contract may exempt a contractor from tax by law. No such law has been enacted to date. A draft oil and gas tax law has been under discussion, which aims to exempt all IOCs, their subcontractors and foreign personnel from any income tax and social security contributions for several years.

In the absence of an oil and gas tax law and as an incentive for major IOCs to invest in the KRI, the Model PSC is structured to provide the IOCs, their affiliates and subcontractors involved in petroleum operations with a de facto tax exemption. In this regard, Articles 31.1 and 31.2 of the Model PSC provide for several rights and obligations related to taxes in connection with the PSC as follows.

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44 Article 39.4 and 39.6 Model PSC.
45 There is considerable controversy as regards the KRG’s constitutional right to legislate on matters relating to taxation. According to Article 110(3) of the Iraqi Constitution, ‘formulating fiscal policy’ falls within the exclusive jurisdiction of the federal government. The KRG’s interpretation of this article distinguished between ‘formulating policy’ and ‘regulating taxes’ where the latter falls within the competencies of the regional government. In practice, this question has not been subject to judicial review and the federal government has not imposed nor collected any taxes in the KRI since 1992.
46 Article 40 KOGL.
i Rights and obligations of the contractor entities

These include the following.

a The IOC, each contracting entity, its affiliates and any subcontractor are exempt from all taxes as a result of their income, assets, and activities under the PSC effectively for the entire duration of the PSC, including but not limited to taxes on income from movable capital, any taxes on capital gains, and any fixed taxes on transfers.47

b The IOC is exempt from any withholding tax, surface tax, windfall tax and additional profits tax as provided in Article 44 KOGL.48

c The IOC is subject to corporate income tax on its income from petroleum operations.49 Payment of such income tax shall be made by the KRG throughout the entire duration of the contract.

d The IOC must provide appropriate tax returns in accordance with applicable law together with a calculation of the amount of income tax due.50

e Each contracting entity shall pay or withhold the personal income tax and social security contributions with respect to its employees.51

Notwithstanding that the model and all signed PSCs exempt a subcontractor from taxes, in practice these exemptions have not been implemented with regard to subcontractors that remain subject to all applicable taxes in the KRI. While the foregoing is not consistent with the terms of the PSC, it is consistent with applicable laws.

Furthermore, in July 2017, the MNR issued decree 3773 which exempts all foreign employees from income tax on the wage they earn in the KRI.

ii Obligations of the government

a The government shall indemnify each contracting entity against any liability to pay any taxes assessed or imposed upon such contracting entity that relate to the tax exemptions granted by the PSC.52

b The government shall pay all income tax on behalf of the contracting entity directly to the KRG tax authorities from the government’s share of profit petroleum and provide the contracting entity with a tax clearance certificate.53

According to the Iraqi Constitution no tax may be imposed nor an exemption made except pursuant to a law.54 Therefore, in our assessment the exemption provided under the PSC may not legally bind the KRI tax authorities; a view widely shared by the Ministry of Finance. In order to effect the tax exemption, the PSC provides for a contractual assumption of the IOC’s income tax liability by the KRG, which is obliged to pay taxes on behalf of the IOC from its

47 Article 31.1 Model PSC.
48 Article 31.4 to 31.7 Model PSC.
49 Article 31.2 Model PSC.
50 Article 31.2 Model PSC.
51 Article 31.8 Model PSC.
52 Article 31.1 Model PSC.
53 Article 31.2 Model PSC.
54 Article 28(1) Iraqi Constitution.
share of profit petroleum, and to indemnify the IOC against a tax liability from which the IOC is exempt pursuant to the terms of the PSC. This results in a de facto exemption for income tax arising under the PSC.

In addition, the PSC further provides for an exemption from customs duties and any other import duties, fees or taxes and an obligation on the government to indemnify the IOC in the event any such duties, fees or taxes are imposed on the IOC.

The PSC also provides that the IOC is obliged to withhold and pay personal income tax and social security contributions on behalf of its employees pursuant to applicable law. Several IOCs negotiated the inclusion of the phrase ‘in respect of its employees who are Iraqi nationals’. While initially the competent authorities did not pursue IOCs in connection with their foreign employees, during the past few years, a number of IOCs have been required to pay all labour-related taxes and social security contributions for both local and foreign employees active in the KRI. One of the contentious issues in passing the KRG draft oil and gas tax law is whether to exempt foreign employees from personal income tax and social security contributions.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Both the KOGL and the Model PSC contain similar provisions pertaining to health, safety and environment. In addition to the requirement for all applicants for a PSC to include conditions for protecting the environment, preventing, minimising and remedying pollution, an IOC is required under the PSC to adhere to prudent international petroleum industry practice with regard to environmental protection as well as applicable laws. IOCs are also required to make payments towards an Environment Fund.

The KRG Law of Environmental Protection and Improvement No. 8/2008 regulates environmental matters such as the protection of water, soil, air and biodiversity, and is applicable to oil and gas operations. In accordance with Articles 4 to 6 of the Law, the Ministry of Environment in the KRI established an Environmental Protection and Improvement Council to oversee and supervise all environmental matters. In 2010, an independent Environmental Protection and Improvement Board was established in the KRI by Law No. 3/2010, which replaced the Environmental Protection and Improvement Council and the Ministry of Environment and has assumed the oversight and supervisory role for the enforcement of Law No. 8/2008.

In addition to specific obligations related to standards for the protection of water, soil, air and biodiversity, any person conducting any activity that has an environmental impact must obtain prior approval from the Environmental Protection and Improvement Board.

Non-compliance with the obligations of the Environment Law may result in no less than one month of imprisonment or fines of between 150,000 and 200 million Iraqi dinars, or both. In addition to the specific penalties provided for in the Law, anyone who causes environmental damage shall be subject to civil compensation and responsibility for removing or correcting the damage.

As regards environmental requirements in connection with decommissioning, the IOC must present a decommissioning plan to the management committee at least 24 months

55 Article 37.1 Model PSC.
56 Article 37(1)(10) KOGL and Article 23.8 Model PSC.
57 Article 42 KRG Environment Law No. 2/2008.
before the estimated date of the end of commercial production including environmental considerations. The IOC has the right, but not the obligation, to create a ‘decommission reserve fund’ during the last 10 years of the PSC’s term. Amounts paid towards the fund shall be recoverable by the IOC as petroleum costs in accordance with the terms of the PSC.58

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The KOGL requires that any IOC operating in the KRI pursuant to a PSC shall establish an office in Kurdistan.59 The term ‘office’ as used does not specify whether the ‘office’ must be a branch office or a separate local legal entity such as a subsidiary LLC. In practice, however, the MNR gives preference to the registration of branch offices.

The procedure for registering a branch entails submission by the parent company of the following documents legalised up to the level of the Iraqi consulate in the country of issuance:

a corporate documents of the IOC (certificate of establishment, commercial register extract, statutes, etc.);

b letter of intent or shareholders’ resolution approving the establishment of the branch and an undertaking that the IOC shall assume all liabilities and obligations of the branch;

c power of attorney granted to the person to be appointed manager of the branch plus a copy of his or her passport;

d evidence of the business premises in KRI; and

e last audited financial statements of the IOC.

The above documents are to be submitted to the Register of Companies along with evidence of registration on the MNR Approved Vendor List (an online registration platform)60 or a decision by the MNR approving this registration. In addition to the foregoing, the branch must appoint a local accountant and lawyer admitted to the relevant Kurdish accountant syndicate and bar association respectively.

The approval and certificate of registration of the branch is usually issued within two to three weeks of the date of submission of the completed set of documents to the Register of Companies.

ii Repatriation of foreign currency

At present there are no foreign currency exchange restrictions applicable in the KRI and foreign companies are free to repatriate funds without restriction. Notwithstanding the foregoing, anti-money laundering requirements imposed by the Iraqi Central Bank and applied by private and public banks may result in delays in receiving and transferring funds into and out of the KRI.

58 Article 38.1 Model PSC.
59 Article 46 KOGL.
60 https://www.mnronline.com/Online/Registration/
The PSC further confirms that the IOC is entitled to convert into dollars or any other foreign currency any Iraqi dinars received from petroleum operations and to freely transfer the same abroad and to pay any subcontractor and its expatriate personnel in foreign currency.

iii Preference to local resources

In addition to the KOGL requiring that IOCs give preference to local manpower from the KRI and other parts of Iraq provided that they have the necessary qualifications, the same obligation also applies to subcontractors. This is also mirrored in both the Iraqi Labour Law applicable in the KRI and the Model PSC. The IOC is required to provide training to local employees and, where possible, ‘to maximise knowledge transfer to the people of the region’. Training may include scholarships, funding for education and secondment of government employees to the IOC. The IOC must provide a training plan and advance funding to the government for recruitment and secondment of government-selected local personnel. Costs for training contained in the training plan and advance funding are recoverable as petroleum costs under the PSC.

The Model PSC entitles the IOC to hire foreign personnel whenever the personnel from the KRI and other parts of Iraq do not have the requisite technical capability, qualifications or experience. However, it does not specify whether the IOC or the KRG shall have the discretion to determine whether local manpower is sufficiently qualified. Therefore, to a large extent, the discretion is left to the IOC. The IOC is required to obtain residency permits from the KRG Ministry of the Interior for all foreign personnel. The permit is only granted based on the approval of the MNR.

As with employment, IOCs and their subcontractors are required to give preference to partnering with local companies and using local products and materials. It is noteworthy that in selecting IOCs the government is entitled to give preference to IOCs that partner with local companies. The training programme submitted by the IOC is also one of the considerations in selecting IOCs.

iv Anti-corruption

The Republic of Iraq is frequently listed among the 10 most corrupt countries in the world by Transparency International. Kurdish officials, worried that this ranking in the corruption index could reflect badly on the KRI, launched a strategic good governance and transparency campaign as early as 2009 in cooperation with the international consulting firm PricewaterhouseCoopers.

Since then, the Kurdistan Region Presidential Anti-Corruption Committee has frequently investigated government actions and government projects, in particular in the

61 Article 29.4 Model PSC.
62 Article 29.9 Model PSC.
63 Article 44(1) KOGL and 23.1 Model PSC.
64 Article 45 KOGL and 23.4 Model PSC.
65 Article 45 KOGL.
66 Article 23.2 Model PSC.
67 Article 23.3.1 Model PSC.
68 Article 23.3 Model PSC.
69 Article 44(2) KOGL.
construction and contracting sector. Consequently, the PSCs provide that any reasonably proven violation of the anti-corruption laws applicable in the KRI shall render the PSC void *ab initio*.

While certain compliance issues regarding doing business in Kurdistan remain, based on the above it seems reasonable to exempt the KRI from the general corruption ranking of Iraq.

IX  CURRENT DEVELOPMENTS

In particular, two factors have characterised the development of the KRI hydrocarbons industry.

On the one hand, the relative security of the region (following the removal of IS) has been outstanding in comparison with central Iraq and had a vastly positive effect on commercial development. Large oil companies and the commercial sector were drawn to the KRI by the economic prospects of the region and were reassured by the absence of terrorist or military attacks. The success of the Peshmerga and Iraqi forces against ISIS in northern Iraq has returned confidence to the region as more companies have started investing once again. For example, UAE-based independent gas company Dana Gas announced a new oil discovery in its KRI fields and a 74 per cent increase in revenue through the consortium Pearl Petroleum (majority owned by Dana Gas) in the first half of 2019. Pearl Petroleum also signed a 20-year gas sale agreement with the KRG earlier this year that would facilitate increased gas production, evidencing its flourishing relations with the KRG.

On the other hand, the lack of a working infrastructure to independently transport hydrocarbons out of the KRI has left many players questioning the sustainability of the KRI’s efforts to establish a prosperous oil industry.

The lack of technical midstream capabilities has been largely rectified. The new pipeline designed to transport oil directly from the Taq Taq oilfield in the KRI to Turkey was finished in December 2013. In July 2014, amid the turmoil created by terrorist attacks of the ISIS terrorist group in northern Iraq, the KRG connected the Khurmala Dome southwards to the oilfields in the disputed territories near Kirkuk by a new pipeline. This allowed the KRG to exploit the vast oil resources of Kirkuk and enabled it to transport oil through the central Iraqi pipeline network to Iraq’s south. Talks between the KRI and Iran for a pipeline capable of transporting up to 250,000bpd of oil from KRI to Iran failed, with Iran reaching agreements with Baghdad instead to transport oil from Kirkuk to Iran.

Despite the development of the above technical capabilities to transport crude oil from the territory of the KRI, the efforts of the central government to prevent independent oil exports from the KRI through widespread legal action against parties involved in these export and sales activities have had serious consequences on the financial situation of the KRI. Kurdish oil is currently regarded as toxic by many oil traders, and it remains difficult for the KRG to find off takers for its oil.

To enable the KRI to continue to develop despite the extreme financial constraints, the KRI parliament passed a law permitting the KRG to raise funds through sovereign borrowing. The Law to Raise Funds Through Borrowing by the Kurdistan Region (Debt Law) was enacted in June 2015. The law allows the KRG to raise funds through the incurrence of debt or issuing guarantees up to an aggregate amount of US$5 billion for the purpose of financing investment projects approved by the KRI’s parliament. Owing to low oil prices and the central government raising doubts as to the competence of the KRI raising independent sovereign debt, the KRI has to date not been successful in placing any bonds on the basis of the Debt Law.
Kirkuk oil exports have resumed through Ceyhan. The KRG has steadily been paying off its debts. The central government took some steps to ease tensions last year, such as lifting a month-long international flight ban imposed on the KRI after the independence referendum and paying a percentage of the overdue salaries of KRG employees. However, the 2018 budget law’s decrease of KRG’s allocation to 12.67 per cent and criticism of KRG’s non-fulfilment of its oil transfer obligations in the 2019 budget law have continued the bitter dispute over the KRG’s share in revenues. Although there have been efforts to strengthen relations, including Prime Minister Abd al-Mahdi’s more cooperative stance towards the KRG, it remains to be seen what actions the new KRG and central government administrations will take to finally settle remaining disputes.
I  INTRODUCTION

Before the Mexican Constitutional amendment in the energy sector known as the Energy Reform was published, private parties were prevented from exploring and extracting hydrocarbons in Mexican territory. All oil and gas development in the country was conducted by Petróleos Mexicanos (Pemex), Mexico’s state oil and gas company. It operated as a vertical monopoly, controlling all oil and gas projects.

In December 2013, an amendment to the Mexican Constitution monumentally changed the legal nature of Pemex to a state productive company, changing the future of the Mexican petroleum industry. Likewise, this amendment now allows our nation to carry out exploration and extraction of hydrocarbons through allocations made to state productive companies and agreements with the latter or with private companies. Moreover, in order to comply with the purpose of the aforementioned allocations and agreements, the state productive companies may also enter into agreements with private companies. However, the hydrocarbons in the subsoil remain the property of the state.

Now Pemex can carry out the exploration and extraction of hydrocarbons on its own, with the support of its subsidiaries and affiliates, or by entering into agreements, alliances or associations with national or international, public or private individuals or corporations. In spite of the radical change in the legal landscape in 2013 for Mexican hydrocarbon exploration and production, Pemex produced 1.8 million barrels of crude oil per day in March 2018, a decrease of 7.6 per cent from the previous year. Pemex’s natural gas production stood at 4,645 million cubic feet per day on average during March 2018, an annual decrease of 13.7 per cent.

On the other hand, as of the enactment of the Energy Reform, 108 exploration and extraction contracts have been awarded. Therefore, a tangible positive investment impact because of the Energy Reform is expected in the medium term.

II  LEGAL AND REGULATORY FRAMEWORK

Following the Constitutional amendment, a number of laws and regulations were issued to give effect to the Energy Reform and to implement, among other things, the opening of the Mexican oil and gas sector to private investment. This ended Pemex’s monopoly over the exploration and extraction of oil and gas reserves in Mexico.

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The amendment’s changes to upstream activities are primarily implemented through the Hydrocarbons Law (LH), Hydrocarbons Law Regulations, Hydrocarbons Revenue Law (LIH), Law of the Coordinated Regulatory Bodies on Energy Matters (LORCME), Law of the National Agency for Industrial Safety and Environmental Protection of the Hydrocarbons Sector (LASEA), regulations and administrative guidelines from the Ministry of Energy (SENER), the National Hydrocarbons Commission (CNH), the Energy Regulatory Commission (CRE) and the Hydrocarbons Industrial Safety and Environmental Protection Agency (ASEA).

i Domestic oil and gas legislation
As mentioned above, the hydrocarbons in the subsoil are property of the state. Now with the Energy Reform, allocations of hydrocarbons can be made to state productive companies and to private companies through exploration and extraction agreements. These agreements are to be awarded through public bidding proceedings. The LH provides for four types of exploration and extraction agreements: (1) services agreements; (2) licence agreements; (3) profit sharing agreements; and (4) production sharing agreements.

A services agreement implies, for contractors, the provision of services not giving rise to a supra-subordination relationship. Therefore, no labour relationship is generated between the contractor and the state. They only mutually seek to generate an economic benefit.

The licence agreement gives contractors the right to extract hydrocarbons owned by the state in a specific area at contractors’ exclusive cost and risk. Contractors shall have the right to the onerous transfer of the hydrocarbons produced provided that, in accordance with the terms of the contract, they are up to date in the payment of the corresponding considerations in favour of the state.

The profit sharing agreement constitutes an association between the state and a private company to carry out exploration and extraction activities. Once hydrocarbons are extracted, the state is exclusively entitled to sell them.

The production sharing agreement gives the contractor ownership of a percentage of the production of hydrocarbons once they have been extracted from the subsoil and quantified in the facilities identified in the contract.

The LH further regulates the hydrocarbon industry’s activities in the national territory, including the recognition and surface exploration of land and sea, hydrocarbons treatment, refining, disposal, commercialisation, transportation and storage.

The LIH establishes the calculation of the income that the Mexican state will receive from the exploration and extraction of hydrocarbons carried out through the allocations to state productive companies and exploration and extraction agreements. It regulates the considerations established, and the provisions on administration and supervision of financial aspects of such agreements, as well as the obligations on transparency and accountability regarding the resources referred to in the LIH.

The LORCME regulates the organisation and functioning of the CNH and the CRE. Finally, the LASEA establishes the ASEA, and determines its attributes, authority, scope of action and activities.
Regulation

The SENER is in charge of establishing, conducting and coordinating Mexican energy policy and supervising compliance. In addition, in the hydrocarbon industry, the SENER grants and revokes assignments, establishes technical guidelines for bidding processes, is in charge of the technical design of agreements, establishes the areas that may be subject to assignments and agreements and awards assignments and grants permits, for oil treatment and refining and natural gas processing. The SENER establishes the coordination mechanisms with the National Centre of Natural Gas Control (CENAGAS), so that the actions of this National Centre are compatible with the sectoral programmes.

Under the Constitution, the executive will count with coordinated energy agencies, the CNH and CRE.

The CNH

In accordance with the LORCME, the CNH has the power to supervise recognition and surface exploration, the exploration and extraction of hydrocarbons, the tender and signing of agreements for the exploration and extraction of hydrocarbons and technical administration of the assignments and agreements for the exploration and extraction of hydrocarbons.

The CRE

Pursuant to the LORCME, the CRE, among others, is responsible for regulating and promoting the efficient development of transport, storage, distribution, compression, liquefaction and regasification activities, as well as the sale to the public of oil, natural gas, liquefied petroleum gas, petroleum products and petrochemicals.

The ASEA

In accordance with LASEA, the ASEA regulates the environmental protection of soil and wild flora and fauna affected by exploration and the extraction, transportation, storage and distribution of hydrocarbons, in order to avoid or minimise the environmental impact of these activities. Likewise, the ASEA has the power to regulate, supervise and sanction in matters of industrial safety, operational safety and environmental protection, in connection with the sector’s activities, and to issue or deny licences, authorisations, permits and registrations for environmental matters.

CENAGAS

Finally, in accordance with the Decree by which CENAGAS was established, this national centre is considered a decentralised public body of the federal public administration that is responsible for the management, administration and operation of SISTRANGAS, the National Integrated System of Natural Gas Transportation and Storage. CENAGAS shall guarantee the continuity and security of the natural gas supply in Mexican territory.

ii Treaties

Mexico is a contracting party to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention). Mexico has also entered into bilateral arbitration treaties with Italy, Brazil and Colombia.

Mexico has entered into multiple reciprocal investment agreements, including with the following countries: Argentina, Australia, Austria, Bahrain, Belarus, Belgium, China, the
Mexico

Czech Republic, Cuba, Denmark, Finland, France, Germany, Greece, Iceland, India, Italy, Korea, Kuwait, the Netherlands, Panama, Portugal, Singapore, Slovakia, Spain, Sweden, Switzerland, the United Kingdom, Trinidad, Turkey and Uruguay. Mexico is also party to a number of trade agreements that establish investment protection rules such as the North America Free Trade Agreement with the United States and Canada.

Mexico has entered into treaties for the prevention of double taxation with several countries, including the following: Argentina, Australia, Austria, Bahrain, Brazil, Canada, China, Colombia, Germany, India, Italy, Luxembourg, Peru, Russia, Spain and the United Kingdom.


III LICENSING

The rights to explore and extract hydrocarbons are granted by service, licence, profit sharing and production sharing agreements. These agreements are granted through bid rounds carried out by the CNH.

Under the LH, the bid rules for each bidding process will provide that the corresponding contract for exploration and extraction may be formalised with Pemex, other state productive companies, and private entities, individually, in a consortium, or a joint venture. The alliances or associations can be made under schemes that allow greater productivity and profitability, including modalities in which they can share costs, expenses, investments and risks, as well as profits, production and other aspects of exploration and extraction. The SENER establishes the contracting model for each contract area that best serves to maximise the state’s income, with the opinions of the Ministry of Finance and Public Credit (SHCP) and the CNH. The bidding process will begin with the publication of the call in the Official Gazette of the Federation.

Those interested in submitting proposals must comply with the pre-qualification criteria on technical, financial, execution and experience elements, under the terms indicated in the guidelines established by the SENER for this purpose. The awarding mechanism may be, among others, an ascending auction, a descending auction or an auction at the first price in a sealed envelope, in which case the envelopes must be presented and opened in the same public session. Proposals may be presented and analysed through electronic means. Bidding criteria must include tiebreaker criteria, which will be included in the corresponding bid rules.

The SHCP will determine the time and conditions under which the minimum and maximum acceptable values for the variable that integrates the economic proposal will be revealed during the bid. The economic proposal shall be understood as the offer submitted by the bidders, prepared in accordance with bid rules. Finally, the corresponding decision must be published in the Official Gazette of the Federation.

As an exception, it will not be necessary to carry out a bidding process and a contract for exploration and extraction may be awarded directly to the owners of mining concessions.

The federal executive, through the CNH, may administratively rescind contracts for exploration and extraction and recover the contractual area for certain serious causes. Some of these causes include the following:
a for more than 180 calendar days, the contractor does not initiate or suspends the activities foreseen in the exploration or development plan for extraction in the contractual area, without justified cause or authorisation from the CNH;

b the contractor does not comply with the minimum work commitment, without justified cause, in accordance with the terms and conditions of the exploration and extraction contract; or

c the contractor partially or totally assigns the operation or the rights conferred in the exploration and extraction contract without prior authorisation.

If the contractor cures the default before the CNH issues the respective resolution, the rescission procedure initiated will not have effect. The exploration and extraction contract will establish the causes for termination and rescission thereof.

IV PRODUCTION RESTRICTIONS

Pursuant to the Mexican Constitution, in the case of oil and solid, liquid or gaseous hydrocarbons, in the subsoil, the property of the state is inalienable and imprescriptible, and no concessions will be granted. However, with the purpose of obtaining income for the state that contributes to the long-term development of the state, as already mentioned, the Mexican state will carry out the activities of exploration and extraction of oil and other hydrocarbons through allocations to state productive companies and agreements with the latter or with private companies.

Exports and imports of hydrocarbons must comply with the Foreign Trade Law, the Foreign Trade General Rules (as issued by the tax authorities every year) and a number of Mexican official standards (NOMs) regarding product specifications, such as quality standards. Furthermore, those interested in the export or import of hydrocarbons shall request their registration beforehand, before the Hydrocarbons Sector of the National Import/Export Registry. Additionally, these activities are subject to a special permit granted by the SENER.

All of the activities related to hydrocarbon matters are subject to special permits (i.e., storage, commercialisation, distribution, transportation, among others). The state productive companies or private investors that intend to conduct such activities are obliged to request the corresponding permit appropriate to the development activity.

In addition to the aforementioned, under the LH, hydrocarbons, oil products and petrochemicals shall meet quality specifications, as well as testing, sampling and verification methods applicable to qualitative characteristics, and volume in the transportation, storage, distribution and retail activities.

The CRE, with the opinion of the Federal Commission of Economic Competition (COFECE), establishes the rules to which the holders of transportation, storage, distribution, retail and commercialisation permits of hydrocarbons, and the users of said products and services, must adhere. The foregoing is to promote the efficient development of competitive markets in these sectors. Among other things, these provisions may establish the strict legal separation between the permissive activities or the functional, operational and accounting separation of the same. These provisions contemplate the cases in which the persons who are the owners of capital stock of end users, producers or marketers of hydrocarbons and who use pipeline or storage transportation services subject to open access, may participate in the capital stock of the permit holders that provide these latter services. The aforementioned imply that the cross-participation does not affect competition, market efficiency and effective open access.
Finally, according to the LH, the CRE is the responsible authority for periodically issuing the tariffs regarding all hydrocarbon matters except for the sale prices of liquefied petroleum gas, diesel and gasoline, which should be settled by market conditions from time to time.

V ASSIGNMENTS OF INTERESTS

As mentioned before, state productive companies or private investors are able to request permits for the development of activities in the hydrocarbons sector. Likewise, permit holders are allowed to assign their permits under the LH. These transactions are subject to approval from the CRE or the CNH in the case of exploration and production agreements prior to the assignment.

Certain requirements have to be met, among which the following stand out: the permits should be valid, the assignor has to comply with all its obligations and the assignee must meet the requirements to be a permit holder and comply with its obligations. In each case, the authorities are required to verify the technical and economic capacity of the assignee. Nevertheless, the authorities have to ask for an opinion from the COFECE, since an assignment can possibly involve antitrust matters.

According to the LH, a resolution should be issued no longer than 90 days after the request is filed. If no resolution is reached by the responsible authority in that term, it is understood that the assignment is approved.

On the other hand, transactions regarding the assignment of corporate and operational control within the companies holding the permits described before are subject to a special and prior authorisation by the CRE. For this kind of assignment, the assignee must prove its technical capacity to perform the activities under the agreement that is to be assigned. If the parties fail to request the corresponding authorisation, different penalties and fines can be applied, as well as the annulment of the assignment.

VI TAX

As mentioned earlier, in Mexico there are four types of agreements for exploration and extraction of hydrocarbons that can be entered into: (1) services agreements; (2) licence agreements; (3) profit sharing agreements; and (4) production sharing agreements. Depending on the characteristics of each agreement, different government take will become applicable as well as the consideration received by the contractor or the state productive company.

i Services agreement

In a services agreement, a private contractor is hired to work on a defined project and paid in cash without retaining any right to any resulting production. Therefore, the contractor is only liable for tax on the income generated by its services to the government.

ii Licence agreement

Under the licence agreement, the contractor is entitled to the extracted oil and gas production, after payment of the government take, which in this case is composed of: (1) the initial signing fee; (2) the contracting quota for the exploratory phase; (3) the royalty; and (4) the rate on the contractual value of hydrocarbons.
### iii Profit sharing agreement

Under this type of agreement, the contractor is entitled to recover authorised expenses, costs and investments incurred in connection with the agreement upon success into the exploration and extraction phases, as well as a percentage of the operational profit. In this case, the government take is composed of: (1) the contractual quota for the exploratory phase; (2) royalty payments; and (3) the agreed percentage of operational profits.

### iv Production sharing agreement

In accordance with this agreement, the contractor is entitled to a percentage of the oil and gas production and optionally to the recovery of the authorised expenses, costs and investments incurred in connection with the agreement upon success in the exploration phase. The government take is composed of: (1) the agreement quota for the exploratory and extraction phase; (2) royalty; and (3) the agreed percentage on operational profit.

In addition, contractors must pay the tax on hydrocarbons exploration and extraction activities, which is payable on a monthly basis, as follows:

<table>
<thead>
<tr>
<th>Phase of activities</th>
<th>Monthly tax (pesos)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Exploratory phase</td>
<td>1,500 per square kilometre</td>
</tr>
<tr>
<td>Production phase</td>
<td>6,000 per square kilometre</td>
</tr>
</tbody>
</table>

Mexican law provides for special rules for companies involved in the exploration and production activities that supersede general rules. For example, new rules were incorporated into the LIH regarding permanent establishment taxation.

A permanent establishment is deemed to exist if foreign tax residents perform hydrocarbon exploration and extraction related services in Mexico for 30 days or more, during a 12 month period. In such cases, permanent establishment taxation is triggered on the attributable income. The same rule becomes applicable to foreign tax residents receiving salary payments from abroad. If they work in Mexico for more than 30 days within any 12-month period, then the salary is subject to Mexican source taxation.

It is important to note that the aforementioned rules are contained within Mexican domestic law and thus can be overridden by tax treaty disposition, providing for longer periods to trigger permanent establishment taxation or employee taxation.

Finally, the LIH allows for more beneficial depreciation rates than those contained within the Income Tax Law for property used in oil and gas exploration and extraction activities, as follows:

- **a** 100 per cent of invested amounts in exploration, secondary and enhanced oil recovery, as well as for non-capitalised maintenance;
- **b** 25 per cent of investments in the exploration and development of oil and gas deposits; and
- **c** 10 per cent of amounts invested in infrastructure for storage and transportation required under the agreement, for example for oil and gas pipelines, terminal, transportation or storage tanks.

The deductible amounts for each taxable year may be limited in accordance with the rules contained within the agreement entered into between the contractor and the government.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

It is important to bear in mind that in Mexico all three levels of government share responsibilities to protect the environment and that variables, such as (1) the location of projects and (2) the communities that may be affected by them, will be determinants to identify the applicable legislation to which they will be subject.

The ASEA becomes the Ministry of Environment and Natural Resources’ (SEMARNAT) specialist unit for all activities involving oil and gas. As mentioned before, among other powers, the ASEA is responsible for directing environmental policy and the creation of systems and specific guidelines for performing these activities. Moreover, the ASEA will come to replace the PROFEPA (the Federal Attorney for Environmental Protection) in its functions of inspection and monitoring compliance with environmental matters.

The ASEA has also assumed among its responsibilities the issuance of authorisations and permits on several environmental matters that used to be distributed in several other SEMARNAT departments. This is how the ASEA came to be in charge of reviewing and authorising permissions that have an impact in a wide range of environmental issues through a ‘sole attention office’. While this might accelerate project response times, it also poses a challenge for the agency with regard to the integration of a multidisciplinary group of public officers to review and authorise all these permits.

Matters regarding the management of water resources in the hydrocarbons sector will remain under the strict supervision of the CONAGUA (the National Water Commission) and the provisions of the National Waters Law and its regulations, as well as the applicable NOMs.

Pursuant to LASEA, decommissioning is the stage of partial or total removal, disassembly, reuse or disposal of equipment and accessories from a facility dedicated to activities for the hydrocarbons sector. Site abandonment is the final stage of a project, typically after the decommissioning of a facility, where the site is left in a safe condition in a definitive way and there are no recognised environmental conditions on the site, or a remediation process has been successfully performed.

The particular characteristics that must be met during these two stages may vary based on the specific activities undertaken during the project, although in all cases it must be referred to in the environmental impact authorisations. However, there are general provisions that indicate the minimum specifications to which the projects are subject to for this stage. Some of these general conditions include: giving notice of abandonment of facilities, providing adequate handling or disposal for all the waste generated during this final stage in order to ensure that the site is free of environmental liabilities and concluding any permit, authorisation, registration or concession issued on behalf of the project holder.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

In all the bidding processes carried out in Mexico for exploration and extraction of hydrocarbons, only Mexican companies may sign the corresponding agreements. In contrast, for the pre-qualification process (in which the experience and capacities of each stakeholder will be evaluated), the bid rules allow a foreign company to participate. However, as mentioned before, it will be necessary to incorporate a Mexican company for the purposes of signing the agreement of reference. Thus, investors may not establish a branch of a foreign corporation as contracting party.
Moreover, companies may participate in the bidding processes individually, in consortium or through a joint venture. In the latter case, the joint venture agreement shall have been entered into pursuant to Mexican laws. Likewise, a consortium will be understood as two or more state productive companies or private companies that jointly submit a proposal within the bidding process for the awarding of the corresponding agreement.

The process for the establishment of a local entity is as follows.

a) A permit from the Ministry of Economy approving the local entity’s name must be obtained.

b) At least two partners are required for the incorporation of a local entity. These members can be either companies or individuals.

c) A set of by-laws and articles of incorporation containing the general corporate governance and management rules of the local entity should be drafted.

d) Once the permit is granted, the powers of attorney are duly granted and formalised and the by-laws drafted, the attorneys-in-fact will appear before a Mexican notary public to request the formalisation of the articles of incorporation and by-laws. The notary public shall issue an incorporation deed, which shall be registered before the corresponding Public Registry of Commerce.

e) The local entity shall be registered before the Federal Taxpayers’ Registry.

f) If the local entity has foreign investment, within 40 business days of the date of the issuance of incorporation deed, the local entity shall be registered before the National Registry of Foreign Investment.

The timing for the establishment of a local entity is approximately one month. In practice, a local entity can start operations once it has been registered before the Federal Taxpayers’ Registry.

ii Capital, labour and content restrictions

Employees in the oil and gas industry have the same rights and obligations as in any other industry or business sector in Mexico. Employers must have an employment contract in place for each employee, regardless of whether the employee is covered by a collective bargaining agreement.

Employers must comply with minimum benefits set forth in the Mexican Federal Labour Law (FLL) at the time of hiring employees such as: (1) 15 days’ salary as Christmas bonus, payable every year by December 20; (2) annual vacation period according to employee’s seniority; (3) 25 per cent of salary corresponding to vacation days as vacation premium; (4) overtime paid at double rate for the first nine hours of work exceeding the normal shift; (5) double salary for work on rest days and holidays; (6) 25 per cent of salary if an employee is required to work on Sundays as a regular workday; (7) profit sharing based on the employer’s 10 per cent taxable income in a fiscal year (January–December); and (8) statutory severance if terminated without cause. Benefits may be enhanced in terms of the applicable collective bargaining agreement and its annual negotiation between the employer and the corresponding trade union.

Similar to any other employer in Mexico, oil and gas companies must hire nine Mexican nationals for each non-Mexican individual. General managers are not considered for the 9:1 ratio required by the FLL, and in the case of technicians and professionals, the law requires them to be Mexican nationals, unless it can be demonstrated that there are no
candidates with the capabilities and experience of foreign workers intended to be hired. In this latter case, the FLL provides that foreign workers may be hired on a temporary basis, without specifying the term of employment.

Foreign workers may render services if a Mexican legal entity hires them, provided the company obtains the employer certificate required by the National Immigration Institute in advance, and the foreign worker files for and obtains a temporary resident work visa. This immigration permit will allow the foreign individual to earn salary and benefits out of a Mexican payroll and contribute for medical coverage from the Mexican Social Security Institute. Another alternative for a foreign worker to render services in Mexico is obtaining a temporary resident visa for non-remunerated activities, which will allow the individual to earn salary and benefits from his or her home country without necessarily becoming an employee for Mexican purposes. Several labour and tax aspects need to be carefully reviewed for this latter alternative.

iii Anti-corruption

Mexico has a National Anti-corruption System (SNA), which is the coordination body between the authorities of all the competent government entities for the prevention, detection and sanction of administrative responsibilities and acts of corruption. The public policies established by the SNA should be implemented by all public entities. Likewise, the rules for this coordination are established in the General Law of the National Anti-corruption System. The aforementioned Law is of recent creation, published in the Official Gazette of the Federation on 18 July 2016.

With the SNA, Mexico intends that anti-corruption strategies are carried out in an inter-institutional coordination framework. This is intended to prevent the carrying out of isolated, uncoordinated and ineffective actions, as has occurred in Mexico prior to the creation of the SNA. Therefore, since the SNA is an integral and transversal system to combat corruption, one of the bodies that integrates it is the Citizen Participation Committee. This Committee is composed of five citizens of probity and prestige who have stood out for their contribution to transparency, accountability or their fight against corruption. Likewise, the SNA shall be replicated in all federal entities, whose integration, attributions and operation shall be developed by the laws of each of the aforementioned entities.

IX CURRENT DEVELOPMENTS

So far, four rounds have been carried out in Mexico. Round Zero worked as the first previous mechanism of market diversification and opening. This round was only applicable to Pemex, since it consisted in evaluating which projects and reserves would continue under the development of the now state productive company, either by itself or through farmouts.

Round One was structured in four bids and comprised five production sharing agreements and 33 licence-type agreements. According to the CNH, during Round One 38 areas of 55 tendered were awarded.

Round Two had four bids. In the first, 10 of the 15 contract areas located in shallow waters of the Gulf of Mexico were awarded. The second bid was composed of 10 contractual areas under a licence agreement modality, three of which have been abandoned and seven of which were awarded. In the third bid, which includes 14 contractual areas, all were awarded. In the fourth bid round, 19 of the 29 blocks offered were awarded.
Finally, Round Three constituted three bids. In the first bid, 16 of the 35 contractual areas offered were awarded. However, since then, Mexico went through a change in its executive power, and the current government decided to suspend the second and third bids of Round Three. In May 2019, the head of the Office of the Presidency, Alfonso Romo, informed the Mexican press that the government continues to evaluate the results of the rounds to determine if they will be reactivated in the future.

For now, it is important to mention that the results of the rounds have been positive. State revenues accumulated up to March 2019 reached US$1,692 million dollars. In May 2019, oil production reached 73.4 MBPD and natural gas production 186.4 MMSCFD.

On the other hand, on 16 July 2019, Pemex presented its 2019–2023 Business Plan, which established Pemex’s strategic path for the next few years.

Under the plan, farmouts were not included. However, Pemex will permit private investment in hydrocarbon production by means of integrated services of exploration and extraction agreements lasting between 15 and 25 years to ensure that the investor receives the payment for the total amount of its expenses with a profit margin.
Chapter 20

NEW ZEALAND

Paul Foley

I INTRODUCTION

New Zealand’s geological history has endowed it with rich petroleum resources, only a small proportion of which have been tapped. These largely unexplored petroleum resources represent one of the country’s most significant economic opportunities.

New Zealand’s producing oil and gas fields are primarily located in the Taranaki basin on the west coast of the North Island.

i Oil

In 2018, oil prices rose and fell sharply but continued to recover after the lows of 2016. Total oil consumption increased 3.1 per cent between December 2017 and March 2018. In the same quarter, petrol imports were up 26.6 per cent and diesel imports were up 6.8 per cent, while indigenous crude oil production was down 11.4 per cent largely because of the shutdown of the Pohokura field after a small leak was discovered in an offshore pipeline.

Most of the oil produced by New Zealand is exported, owing to its high quality and the configuration of New Zealand’s sole domestic refinery. In the December 2017 to March 2018 quarter, the domestic refinery saw output of regular petrol increase by 33 per cent, diesel increase 6.5 per cent and jet fuel increase 14.5 per cent, while premium petrol decreased 6.8 per cent.

ii Gas

In 2019, gas use for power generation was down 16 per cent in the year from March 2018 to March 2019, with overall gas supply constrained by ongoing long-term maintenance at one of New Zealand’s largest gas fields, Pohokura. Production of gas is dominated by the Pohokura and Maui fields, which are responsible for over half of New Zealand’s domestic gas production.

1 Paul Foley is a consultant at MinterEllisonRuddWatts.
New Zealand does not currently export natural gas, and lacks LNG facilities, but natural gas is a vital input into the domestic energy market. Direct consumption of natural gas by consumers is low, with use by households accounting for only a small percentage of total use. Gas used for electricity generation and cogeneration has continued to fall, with the share of electricity generated from renewable sources continuing to rise.7 Natural gas is transmitted throughout the North Island through high-pressure gas transmission pipelines which connect to medium and low-pressure gas distribution pipelines. These pipelines connect the oil fields of Taranaki with industry and consumers throughout the North Island.

iii Government policy towards the sector
A change of government in November 20178 has seen a shift in focus regarding the oil and gas sectors in New Zealand, especially in relation to offshore exploration. In November 2018, Parliament passed the Crown Minerals (Petroleum) Amendment Act, removing the ability to issue new permits for offshore oil or gas exploration, and restricting future block offers to onshore locations.

This legislation does not affect current permit holders (who will be entitled to continue to explore for and produce any commercial quantities of hydrocarbons that are discovered). Onshore block offers are set to continue with the current 2018 block offer having closed in August 2019.9

The decision to no longer grant new permits for offshore exploration was stated to be in support of the government’s goal of New Zealand becoming a net zero-emission economy by 2050, with an interim goal of making New Zealand’s electricity system 100 per cent renewable by 2035. The decision was subject to significant criticism at the time for failure to sufficiently identify how the change contributes to the desired outcome (as in the absence of other actions that reduce use, there will simply be an increase in the net imports of hydrocarbons).

The government introduced the Climate Change Response (Zero Carbon) Amendment Bill in June 2019, which encapsulates these goals. The Bill is currently before the Environment Select Committee.

In 2011, the then government released the New Zealand Energy Strategy 2011–21, Developing our Energy Potential. The strategy sets out how the government intends to help develop New Zealand’s energy resources. In 2017, the government released the New Zealand Energy Efficiency and Conservation Strategy 2017–22, Unlocking our energy productivity and renewable potential. The strategy supports the New Zealand Energy Strategy 2011–21 and sets out the objectives, actions and targets for energy efficiency and renewable energy for the next five years. The ongoing validity of these policy statements is questionable in light of the changes made by the new government.

Several reforms to oil and gas regulation were passed in 2013. Experience under those reforms is limited and ongoing changes to the detailed rules of operating in the sector are expected to continue for the foreseeable future, particularly in light of the current government’s stance on the oil and gas sector.

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7 Ministry of Business, Innovation & Employment, Energy in New Zealand 2016 (Ministry of Business, Innovation & Employment) at 44.
8 The government now comprises a coalition between the Labour, Greens and New Zealand First political parties.
9 The Block Offer 2018 is limited to areas within the onshore Taranaki region.
II LEGAL AND REGULATORY FRAMEWORK

i Background

Constitutional structure

New Zealand is a constitutional monarchy, where decision-making power is distributed across three branches of government: Parliament, the Executive and the judiciary. Parliament makes the law, the Executive administers the law and the judiciary interprets the law through the courts.

New Zealand has no single written constitution or any form of law that is higher than the laws passed in Parliament. The legal rules of New Zealand are contained in a number of sources, concentrated in legislation passed by Parliament and court decisions made by judges.

Regional and local government

Regional and local government decision-making is an important consideration for investors in the oil and gas sector. New Zealand has 11 regional councils and 67 territorial authorities. Regional and local government make decisions and set the direction for promoting the social, cultural, environmental and economic wellbeing of their communities within the parameters set by central government.

Ownership of oil and gas

The Crown owns all of New Zealand’s in-ground petroleum resources, and has exclusive sovereign rights to petroleum resources in New Zealand’s Exclusive Economic Zone and Continental Shelf. A permit must be obtained from the Crown to carry out any prospecting, exploration or mining activities. If extracted in the course of activities authorised by a permit, ownership of petroleum passes to the holder of that permit.

Domestic oil and gas legislation

New Zealand’s oil and gas sector is governed by the Crown Minerals Act 1991 (CMA). The CMA sets the broad legislative policy for prospecting, exploration and mining of minerals, which includes petroleum, in New Zealand. The CMA is administered by NZ Petroleum & Minerals (NZP&M), which is a branch of the Ministry of Business, Innovation & Employment. The Continental Shelf Act 1964 extends the application of the CMA to include petroleum in the seabed and subsoil of the continental shelf.

The CMA is supplemented by important pieces of subordinate legislation, including the:

a Minerals Programme for Petroleum 2013, which establishes the policies, procedures and provisions relating to petroleum that are to be applied under the CMA. The CMA requires functions and powers exercised under the CMA to be carried out in a manner that is consistent with the policies, procedures and provisions of any relevant minerals programme;

b Crown Minerals (Royalties for Petroleum) Regulations 2013, which cover royalties and royalty reports for petroleum mining permits issued after 24 May 2013;

Crown Minerals (Petroleum) Regulations 2007, which specify the information that permit or licence holders must supply and includes forms for applying for, transferring and surrendering permits;

Crown Minerals (Petroleum Fees) Regulations 2016, which outline the fees payable for petroleum under the CMA;

Crown Minerals (Royalties for Minerals Other than Petroleum) Regulations 2013, which cover royalties and royalty reports on mining permits;

Crown Minerals (Minerals other than Petroleum) Regulations 2007, which cover requirements and procedures for permit applications, permit changes applications, royalty returns and payments, reporting to the Crown on prospecting and exploration and lodging core and samples with the Crown; and

Crown Minerals (Minerals Fees) Regulations 2016, which outline the fees payable for minerals and coal under the CMA.

The government has signalled a probable review of these rules and regulations in light of its policy to no longer issue new offshore prospecting or exploration permits.

Environmental legislation relevant to the oil and gas sector is discussed at Section VII. The most important statutes are the Resource Management Act 1991 (RMA) and the Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012 (EEZCSA).

New Zealand has developed an internationally competitive royalty regime. The regime stipulates that mining permit holders pay either an *ad valorem* royalty or an accounting profit royalty, whichever is greater in any given year. The royalty rates are either:

- a 5 per cent *ad valorem*, that is 5 per cent of the net revenue obtained from the sale of petroleum; or
- b 20 per cent of the accounting profit of petroleum production.¹³

**Regulation**

NZP&M is the regulatory body with primary responsibility for oil and gas regulation in New Zealand. Other agencies involved in regulating the sector include district and regional councils, the Environmental Protection Authority (EPA), WorkSafe New Zealand, Maritime New Zealand and the Department of Conservation (DOC).

NZP&M’s role includes managing the permitting regime, managing regulatory compliance and collecting Crown revenue. NZP&M also consults with Māori stakeholders and provides the public with information about regulation of the industry.

**Treaties**

New Zealand is a signatory to the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards 1958 and the United Nations Convention on the Law of the Sea 1982. New Zealand is party to a number of trade treaties and international conventions, including the New Zealand–China Free Trade Agreement, Australia and New Zealand Closer Economic Relations and the Trans-Pacific Strategic Economic Partnership. New Zealand has a network of 40 double tax agreements in force. These include agreements with Australia, China, the United Kingdom and the United States.

III LICENSING

i Overview
The main instruments required to undertake petroleum activities in New Zealand are:

a a permit under the CMA;
b the required consents under the RMA or the EEZCSA; and
c if necessary, an access arrangement with the land owner and occupier.

The CMA separates mining operations into three stages: prospecting, exploration and mining. A permit under the CMA is required for each of these stages.\textsuperscript{14}

ii Prospecting
Petroleum prospecting permits (PPP) are required for prospecting activities such as desktop studies, grab sampling and geophysical, aerial and seismic surveys. An application for a PPP is submitted in respect of an area nominated by the applicant, and is assessed on the applicant’s technical and financial capability to undertake the proposed work and on the applicant’s record of compliance. Prospecting permits are granted on the basis that prospecting will increase knowledge of New Zealand’s petroleum resources; if the proposed prospecting is unlikely to materially add to existing knowledge, a permit will only be granted if special circumstances exist.\textsuperscript{15}

Prospecting permits are typically non-exclusive and are granted on the basis that the holder has no subsequent right to obtain an exploration or mining permit.\textsuperscript{16} They are granted for a maximum four-year period, with no right of extension.

iii Exploration
A petroleum exploration permit is required for activities such as seabed sampling, detailed seismic surveying and the drilling of exploration wells. Exploration permits are allocated in an annual tender process known as a petroleum exploration permit round (or block offer).\textsuperscript{17}

The geographical scope of future block offers has been substantially reduced by the Crown Minerals (Petroleum) Amendment Act, which prevents offshore block offers altogether and, for 2018, limits onshore block offers to acreage in the Taranaki region. See more discussion of government policy in Section I.

The block offer is a competitive allocation process. In the majority of cases the permit will be allocated to the party proposing an exploration programme that has the best information-gathering value and that is most likely to find petroleum deposits in a timely manner, provided that the programme is technically appropriate and credible.\textsuperscript{18} Where there is high prospectivity and particularly strong competitive interest, the permit may instead be allocated to the party that makes the highest cash bid (subject to the party meeting other requirements).

Regardless of the method of allocation, NZP&M will assess each applicant’s technical and financial capability and compliance history. A high-level assessment will

\textsuperscript{14} Crown Minerals Act 1991, Section 8.
\textsuperscript{16} Minerals Programme for Petroleum 2013, at 4.2.3 and 6.2.5.
\textsuperscript{17} Minerals Programme for Petroleum 2013 at 7.2.
\textsuperscript{18} Minerals Programme for Petroleum 2013, at 7.2.3.
also be undertaken to determine whether an applicant is likely to meet health, safety and environmental legislative requirements. Exploration permits are granted for up to 15 years, depending on their location, but may be extended for appraisal activities.19 Any exploration permit granted is subject to the conditions advertised in the Notice of Permit Round, or agreed upon by the Crown and the person seeking the permit.20 Exploration permits include a subsequent right to apply for a mining permit.21 Permit holders must notify NZP&M as soon as practicable, and not later than 20 working days after making a discovery of petroleum.22

iv Mining
Petroleum mining permits (PMP) authorise the holder of a permit to mine petroleum in a particular area.23 Exploration Permit holders who have discovered petroleum in the exploration area are entitled to exchange their permit for a mining permit provided that they can satisfy the Minister that they have discovered a petroleum field and can satisfy certain requirements in the CMA and Petroleum Programme.24 A mining permit can be granted for up to 40 years.25

v Iwi and hapū consultation
NZP&M will consult with local Māori iwi and hapū (tribes and family groups) before issuing a prospecting, exploration or mining permit. This is consistent with the Crown’s obligations under the Treaty of Waitangi and Treaty settlements. Permit holders have an obligation to provide NZP&M with an annual report detailing the permit holder’s engagement with iwi or hapū in the area to which the permit relates.26

vi Information sharing
Permit holders of all types have an obligation to collect and share particular information with NZP&M.27 In the case of exploration and mining permits, NZP&M will make this information publicly available five years after it is collected, or when the permit to which it relates expires. Information obtained under a prospecting permit will generally not be made publicly available until 15 years after it is collected, unless the information is collected by a non-speculative prospector and a block offer for the area to which the prospecting permit relates has closed.

19 Crown Minerals Act 1991, Sections 35(3) and 35(4); Minerals Programme for Petroleum 2013 at 7.8.
20 Minerals Programme for Petroleum 2013, at 7.3.
22 Minerals Programme for Petroleum 2013, at 7.11.1.
26 Crown Minerals Act 1991, Section 33C.
vii  Revocation of permits

A permit may be revoked if a condition of the permit, the Act or the regulations has been contravened, or if a payment is overdue.28 Prior to revocation, the permit holder must be given a notice specifying the grounds for revocation and given an opportunity to remedy these grounds or provide a reason why the permit should not be revoked or transferred.

In February 2019, Parliament passed the Crown Minerals Amendment Act, which, among other things, extended the grounds for revocation of tier 1 permits. Under this Act, a tier 1 permit may be revoked if a change of control of a permit holder occurs without the prior consent of the relevant minister.29

Tier 1 permits are required for all prospecting, exploration or mining operations that relate to petroleum, as well as for complex, higher-risk-and-return mineral operations.

viii  Access to land

A permit under the CMA does not give the permit holder any rights to access the land to which the permit relates.30 The permit holder must enter into an access arrangement with the land owner before it can commence prospecting, exploration or mining.31 There is an exception to this rule for minimum impact activities which, subject to conditions, may be carried out without an access arrangement provided that written notice is provided to the land owner and occupier.32 An access arrangement must be made with the relevant minister to access the common marine or coastal area since the passing of the Crown Minerals Amendment Act in February 2019, which reflects the government’s stance of restricting new permits for offshore exploration.33

Access to minerals on Crown-owned land has special challenges, particularly when the land is administered by the DOC. The CMA provides that an access arrangement in respect of Crown land can be entered into by the land-holding minister, which in most cases is the Minister of Conservation. An access arrangement cannot be granted in respect of any land listed in Schedule 4 of the CMA, except in very limited circumstances.34 Schedule 4 protects land that has been given a high conservation status and includes most National Parks and Marine Reserves.

Where the land in question is administered by the DOC, a range of information is required to be submitted with the application, including an assessment of the environmental effects of the activity. In practice, the DOC will not grant an access arrangement until a permit under the CMA and all necessary consents under the RMA have been obtained.

Once an access arrangement has been agreed then an Authority to Enter and Operate must be obtained before prospecting, exploration or mining can commence. Further information, including current insurance details, may need to be provided to the DOC before authority will be granted. An Authority to Enter and Operate can be granted for up to 12 months at a time, after which it will need to be renewed.

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29 Crown Minerals Amendment Act 2019, Section 8
33 Crown Minerals Act 1991, Section 54A.


IV  PRODUCTION RESTRICTIONS

Restrictions on production entitlements (if any) are set in mining permit conditions. There are no general restrictions on exports of oil and gas from New Zealand nor are there any requirements for sales of production into the local market. However, the Minister of Energy and Resources does have the power under the CMA to require a permit holder to refine or process in New Zealand any petroleum that the permit holder extracts.35 Where permit holders are required to refine or process in New Zealand, the Minister may make a further order prohibiting that petroleum from being exported.36

New Zealand has one domestic refinery located in the North Island and owned by a publicly listed company. It principally refines imported crudes.

There are no laws regulating oil and gas price setting in New Zealand. However, price setting is subject to competition law and the provisions of the Commerce Act 1986 will apply generally to oil and gas pricing. See more discussion of the Commerce Act at Section VIII.iv.

V  ASSIGNMENTS OF INTERESTS

Petroleum and oil transfers

Petroleum prospecting permit holders can transfer or assign their interest if the relevant minister consents. The minister must be satisfied as to the transferee’s technical and financial capability to assume the permit interest. This may also require the provision of a guarantee from the parent entity of the incoming permit holder. There is a small fee payable – currently NZ$2,530 including goods and services tax. Once the relevant criteria are satisfied, no other payments are required to complete the assignment.

An application for consent must be made within three months of the date of the agreement assigning the interest. This time limit and a similar process also applies to changes of control of a permit holder. An exception to this applies to a change of control application relating to a tier 1 permit holder, as these changes of control are required to be made to the relevant minister at least three months before the date on which the proposed change of control takes place. Failure to obtain consent before a change of control takes place provides grounds for the relevant minister to revoke the permit of the operator.37

The government generally does not have a right of first refusal or preferential purchase right in the event of a transfer.

Depending on the value of the transaction and whether and land is involved, the assignment of an interest may also give rise to further consent requirements (discussed in Section VIII).

VI  TAX

i  Taxation overview

Oil and gas companies operating in New Zealand will pay income tax and goods and services tax (GST). There is no capital gains tax in New Zealand, although certain instances of acquiring and disposing of assets may be taxable, including the disposal of petroleum mining assets. There is no stamp duty in New Zealand.

Income tax

A New Zealand-resident company is taxed in New Zealand on its worldwide income, whether derived locally or from overseas. A non-resident company operating in New Zealand is only subject to tax on income sourced from New Zealand. This includes offshore activity within the Exclusive Economic Zone. The corporate income tax rate in New Zealand is 28 per cent, although some entities may have different tax rates.

Company losses can be carried forward if certain levels of ownership are maintained, and dividends paid may have imputation credits attached to them (designed to prevent double taxation). Certain business expenses may be deductible, including exploration costs, development costs and removal or restoration costs.

Withholding taxes

In New Zealand, withholding taxes may be required to be withheld and paid to the Inland Revenue Department on some payments (for example, payments of interest, royalties or dividends, or payments made to non-resident contractors). There are different rates for resident withholding tax and non-resident withholding tax, and different rates apply for different types of payment.

ii  Tax treaties

New Zealand has 40 double tax treaties, which generally follow the Organisation for Economic Co-operation and Development (OECD) model and can override the application of domestic New Zealand tax rules in some situations. There are a further 21 countries (mostly offshore financial centres) that have concluded Tax Information Exchange Agreements (TIEAs) with New Zealand. Out of these, 19 are in force.

iii  Other tax considerations

Goods and services tax is generally chargeable on supplies of goods and services made in New Zealand. GST is generally imposed at 15 per cent, but certain supplies of certain goods or services can be exempt, or have GST charged at zero per cent.

New Zealand has transfer pricing and thin capitalisation rules that can apply to all businesses with non-resident owners. The New Zealand transfer pricing rules are modelled on guidelines developed by the OECD.

In addition, specific tax rules (and exemptions) may apply to certain oil and gas industry participants and to specific petroleum exploration expenditure, petroleum development expenditure or petroleum mining assets.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Resource Management Act 1991 (RMA)
Most mining operations located onshore or within 12 nautical miles of New Zealand’s territorial limit will require resource consent under the RMA in addition to a permit under the CMA.

The RMA is the principal environmental and development statute in New Zealand. Under the RMA, local authorities are largely responsible for the enforcement of environmental rules and the issuing of individual resource consents. Whether resource consent is required depends on the activity taking place and on local councils’ district or regional plans. The consent process weights potential benefits for the community against potential impacts on the environment and other interests.

A resource consent application must be accompanied by an assessment of the effects that the activity is likely to have on the environment. In the case of mining activities, several expert reports may be required to satisfy this requirement.

ii Marine and Coastal Area (Takutai Moana) Act 2011
The Marine and Coastal Area (Takutai Moana) Act 2011 provides for the special status of the common marine and coastal area as an area that is incapable of ownership. The common marine and coastal area is the area extending from the line of mean high-water springs (essentially the high-tide mark) to the 12-nautical-mile territorial limit.

The Act guarantees public access to the common marine and coastal area and recognises and protects customary interests within it. Interests can take the form of protected customary rights or customary marine title. Customary marine title confers on the title group a set of rights to influence what activities take place in the area and the management of these activities. Customary marine title has significant implications for the mining sector as it will be necessary to negotiate with iwi to obtain access to a customary titled area.

A number of applications have been made since the Act was passed in 2011, but no customary marine titles areas have yet been established. Applications closed in April 2017.

iii Emissions trading scheme
To address New Zealand’s obligations under the Kyoto Protocol, the government has established an emissions trading scheme. Oil and gas that is used in New Zealand is covered by the scheme. Exports of oil and gas are, consistent with international practice, not subject to the regime.

iv The Exclusive Economic Zone
The Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012 (EEZCSA) came into force on 28 June 2013. The Act established a legislative framework for environmental management in New Zealand’s Exclusive Economic Zone and Continental Shelf, with the purpose of promoting sustainable management of the natural resources in this area. It applies to activities taking place more than 12 nautical miles from the coastline.

The Act classifies activities as permitted, discretionary or prohibited. The classification depends on the degree of harm or potential harm from an activity. Marine consents from the Environmental Protection Agency (EPA) are required for those activities that are not
permitted. Marine consent applications must also include an impact statement, which will be publicly notified by the EPA. Similar to resource consents, the marine consent process weighs the potential benefits and impacts of an activity.

The Act was amended by the Exclusive Economic Zone and Continental Shelf (Environmental Effects) Amendment Act 2013, which enables existing petroleum operators to continue operating while a decision is made on their consent application or applications, and any subsequent objections or appeals are determined. To benefit from this provision, existing operators must submit a marine consent application to the EPA and have it accepted as complete nine months before their Crown minerals mining permit or privilege expires.

v  Code of Conduct for Minimising Acoustic Disturbance to Marine Mammals from Seismic Survey Operations

This Code was issued by the Department of Conservation in 2013 and established a regime to minimise the impact of seismic surveys on marine mammals. It is a condition of the grant of a marine permit under the EEZCSA that permit holders comply with the Code. The Code is also open to voluntary adoption and represents industry best practice.

vi  Maritime Protection Rule Part 131

The Environmental Protection Authority administers the Maritime Rule Part 131, which provides rules for offshore installations. Part 131 requires operators to develop an oil contingency plan which must be individually approved for all offshore installations before drilling can begin.

vii  Decommissioning

Oil companies and contractors contemplating the decommissioning of facilities and infrastructure need to obtain approval to remove or discard a structure. Approval is obtained either through the marine consenting process (EEZCSA) or resource consenting process (RMA). Under the Health and Safety at Work (Petroleum Exploration and Extraction) Regulations 2016, a safety plan must also be provided to WorkSafe New Zealand for approval before a production facility can be retired. Wells must also be plugged in accordance with regulations.

Recent changes to the EEZCSA have introduced the concept of a decommissioning plan in relation to decommissioning offshore facilities. These changes do not apply until the date on which the first decommissioning plan regulations made under Section 29E come into force. A decommissioning plan must identify the offshore installations, structures, submarine pipelines, and submarine cables that are to be decommissioned, fully describe how they are to be decommissioned, and include any other information required by the regulations. All New Zealand’s offshore fields remain in production so decommissioning is yet to take place in our marine environment. However, the Tui Area oil field in the Taranaki Basin is likely to be decommissioned by 2025.
VIII  FOREIGN INVESTMENT CONSIDERATIONS

i  Establishment

When choosing to enter New Zealand, foreign investors can:

a  register a branch of an overseas company on the New Zealand register;
b  incorporate a different entity such as a partnership or limited partnership; or
c  incorporate a New Zealand subsidiary of an overseas company.

Incorporating a limited liability company in New Zealand is a relatively quick and easy
process. If all the information is at hand (which may include identification information
required for anti-money laundering purposes), the process can take as little as one to three
business days.

Companies are not required to have a constitution, but will need at least one shareholder,
one director and a registered office address in New Zealand.

Under recent changes to company law legislation, all New Zealand companies are
required to have at least one director who is resident in New Zealand, or resident in, and
a director of a company resident in, Australia (a prescribed country). The list of prescribed
countries may be expanded in the future.

ii  Capital, labour and content restrictions

There are no generally applicable restrictions on the movement of capital or access to foreign
exchange in New Zealand. Oil and gas operators are permitted to hire foreign workers,
provided that immigration and employment requirements are met. There are no local content
or local hiring requirements.

iii  Overseas Investment Act 2005

The New Zealand government regulates foreign investment though the Overseas Investment
Act 2005 (OIA). Under the OIA an overseas person must obtain consent for a transaction
which will result in overseas investment in 'significant business assets' or 'sensitive land'.

An overseas investment in significant business assets is defined as:

a  acquiring 25 per cent or more of rights or interests in securities if the consideration, or
the value of the securities or the New Zealand assets of the target and its 25 per cent or
more subsidiaries, exceeds NZ$100 million; or
b  establishing a business (that is carried on for more than 90 days in any year, whether
consecutively or in aggregate) or acquiring property used to carry on a business if the
consideration exceeds NZ$100 million.38

An overseas investment in sensitive land may include an investment involving farmland,
certain types of reserves and conservation land, and land adjoining the foreshore, if this land
exceeds the area prescribed in the OIA.39 A permit under the CMA or a licence under the
Continental Shelf Act is not considered an interest in land for the purpose of the OIA.

Consent will generally be granted to an overseas investment where the overseas person can demonstrate that they have the business experience, acumen and financial commitment to make the investment successful and that the investment will, or is likely to, benefit New Zealand.

iv Competition

Entrants into the New Zealand oil or gas markets should also consider whether their investment will trigger any requirements under the Commerce Act 1986. The Commerce Act prohibits acquisitions that would have the effect, or likely effect, of substantially lessening competition in a market.\textsuperscript{40}

v Anti-corruption

New Zealand has a reputation for being a country with a transparent system of government and low levels of corruption. In 2018, New Zealand was ranked number two, being the second-least corrupt country in Transparency International’s corruption perceptions index.

Bribery and corruption are offences in relation to both the private sector\textsuperscript{41} and the public sector.\textsuperscript{42} The Anti-Money Laundering and Countering Financing of Terrorism Act 2009 requires financial institutions and casinos to take steps to prevent money laundering and the financing of terrorism. New Zealand ratified the United Nations Convention against Corruption in 2015.

IX CURRENT DEVELOPMENTS


The Crown Minerals Amendment Bill was enacted on 18 February 2019. The Act has made a number of changes to the Crown Minerals Act 1991, including:

\begin{itemize}
  \item[a] extending the grounds for revocation of permits issued to include situations where a change of control of a tier 1 permit holder has occurred without the prior consent of the relevant minister;
  \item[b] introducing offences for failure to obtain prior consent for a change of control of a tier 1 permit holder from the relevant minister and failure to notify the relevant minister upon a change of control occurring in the case of permit holders who are not tier 1 permit holders;
  \item[c] clarifying the access provisions for land set out in Schedule 4. Under the Act, a permit holder may prospect, explore or mine on or in land to which the permit relates only in respect of land that is not subject to a customary marine title order or agreement, or in accordance with an access arrangement agreed in writing between the permit holder and the relevant minister or ministers; and
  \item[d] introducing new offences for breaches of change of control requirements in the Act, as well as quantifying the fines that apply to certain offences.
\end{itemize}

\textsuperscript{40} Commerce Act 1986, Sections 27–29.
\textsuperscript{41} Secret Commissions Act 1910.
\textsuperscript{42} Crimes Act 1961.
As indicated in Section I, this amendment along with the Crown Minerals (Petroleum) Amendment Act 2019 provides the legislative framework for the government’s ban on new offshore permits.

ii Permit changes and withdrawals

Under the current permit regime, the Crown is able to attach conditions to any permit it grants. Invariably, this will result in a permit incorporating a time-based work programme under which the holder commits to undertake certain work by a series of set dates.

Holders may be given the option after completing certain work (e.g., acquisition of seismic data and its processing) of committing to complete the next defined task (such as the drilling of a well) or of surrendering the permit.

The sharp downturn in oil prices in 2016 reduced the financial incentive for permit holders to fulfil these conditions and the potential for farm-in partners to be found to contribute to the cost of complying with the work programme obligations. Changes to conditions and extensions of time to complete work are permitted under the Act and it is expected that the number of such applications submitted to NZP&M increased. To amend the conditions of a permit, permit holders must apply to NZP&M at least 90 days before a permit condition is due to have been completed. Applications must be supported by sufficient justification for the change to be approved.

Where the change involves a total withdrawal from a permit before committed work is done, the permit holder can be required to complete that work or, if released from that obligation in that instance, the holder’s future ability to obtain permits in New Zealand may be adversely affected.

iii Trans-Pacific Partnership (TPP)

New Zealand and 11 other Asia-Pacific countries, including the United States, signed the TPP fair trade agreement in February 2016. In January 2017, the United States’ president signed a Presidential Memorandum to withdraw the United States from the TPP. The agreement as it stands cannot enter into force without the United States. The aim of the agreement is to lower trade barriers and establish a common legal framework in areas such as intellectual property and environmental law. If acceded to, the agreement is likely to have consequences for the oil and gas sector.

In light of the United States withdrawing from the TPP, New Zealand has signed the Comprehensive and Progressive Agreement for Trans-Pacific Partnership (CPTPP) with 10 other Asia-Pacific countries. The aim of the CPTPP is much the same as the TPP. The CPTPP was ratified on 24 October 2018.

iv GNS Science research programme for petroleum exploration

MBIE awarded NZ$9.6 million over four years to GNS Science in 2015 to fund a research programme focusing on improving the chances of finding oil and gas accumulations in New Zealand’s sedimentary basins.

The research has focused on petroleum movement underground, and how petroleum is affected by the particular rock formations that generate, or are likely to generate, petroleum (known as ‘source rocks’). The research also attracted co-funding from international oil exploration companies and had a broad scope. It is hoped that this programme will help encourage and assist new exploration investment in New Zealand. The programme comes to an end in 2019.
v  **Health and safety**

The Health and Safety at Work Act 2015 came into force on 4 April 2016. The Act, which was modelled on Australian health and safety legislation, introduced the concept of persons conducting a business or undertaking (PCBUs). PCBUs have a primary duty of care to ensure ‘so far as is reasonably practicable’ the health and safety of workers and others. The implications of the new PCBU concept require particular consideration by non-operators within joint ventures.

The Act also introduced strict new due diligence obligations on directors, partners and senior managers of businesses operating in New Zealand. The penalties for non-compliance for both individuals and companies have increased under the new Act, and there is likely to be a stronger focus from the regulator on ensuring the health and safety of workers in the future.

vi  **Financial security regime for offshore installations**

The Marine Protection Rules, Part 102, were amended in August 2017. The amendment followed the publication of a discussion paper, *Improving the Financial Security Regime for Offshore Oil and Gas Installations*, by the Ministry of Transport in December 2016, as well as extensive consultation between the Ministry of Transport and the Ministry of Business, Innovation and Employment.

The Marine Protection Rules Part 102 applies to oil tankers carrying more than 2,000 tonnes of persistent oil in bulk as cargo, other ships of 400 gross tons or more and regulated offshore installations within New Zealand continental waters.

The amendments made to Part 102 aim to give greater protection to the government and the public by ensuring that operators have the financial means to cover their liabilities should an adverse event occur. The amendments included:

a  introducing a financial assurance requirement sufficient to cover the costs of well control;

b  introducing a scaled framework for the level of financial assurance required for clean-up and compensation, which will result in an increase to the level required for most installations; and

c  refining the scope of liabilities under Part 26A of the Maritime Transport Act 1994 that the financial assurance must cover, to address the mismatch of current requirements with conventional insurance policies.

The Maritime Transport (Offshore Installations) Amendment Bill is currently before the Transport and Infrastructure Committee.

The Bill proposes to make a number of changes to the Maritime Transport Act 1994, including:

a  clarifying and strengthening the requirements on owners of offshore oil and gas installations to hold insurance (or other financial security) in relation to their liability for clean-up and compensation resulting from an oil spill;

b  providing certainty in relation to the liability of insurers to the Crown and to other third parties who are affected by such spills; and

c  clarifying that rules may specify the types of liability that will need to be insured against at a range of levels and may provide for the insurance or other financial security to cover the cost of well control measures and other costs of implementing marine oil spill contingency plans.
The proposed amendments will be supported by amendments to the Maritime Protection Rules, including Part 102. The Bill aims to enable owners of regulated offshore installations to meet the Maritime Transport Act 1994’s requirements through using insurance policies that are consistent with internationally available best practice policy wording and available on the international market. Consultation on amendments to the Maritime Protection Rules will be open once the Bill is passed.
I INTRODUCTION

The Nigerian petroleum industry established since the first significant crude oil find at Oloibiri in the Niger Delta in 1956 has steadily grown to be one of the largest oil and gas producer in Africa. Although Nigeria is widely known for its crude oil production, it is often referred to as a gas province with pockets of oil. This is evidenced by the fact that Nigeria's current recoverable oil reserves are estimated at 28.5 billion barrels, with an average of about 2.5 million barrels per day being extracted, while its associated and non-associated gas reserves are estimated to exceed 166 trillion standard cubic feet (tcf).

The industry is the major driver of the Nigerian economy, and the government of the Federal Republic of Nigeria regulates and actively participates in this industry through its national oil company, the Nigerian National Petroleum Corporation (NNPC). The industry is in itself divided into three major sectors – the upstream, midstream and the downstream sectors.

The upstream sector, the most active sector of the Nigerian petroleum industry, is largely export-focused and until recently dominated exclusively by international oil companies. The Nigerian government’s marginal fields licensing regime and its content development drive has led to increased participation of indigenous oil companies in the petroleum industry.

The midstream and downstream sectors are dominated by indigenous players. Both sectors, excluding liquefied natural gas (LNG), are significantly underdeveloped as Nigeria’s refineries are currently producing approximately 10 million litres of petroleum products per day, which is remarkably low when compared with Nigeria’s daily consumption of about 35 million litres per day. As a result, there is heavy reliance on the importation of petroleum products in the downstream sector, which, until May 2016, were heavily subsidised by the government. However, in an apparent move towards deregulation of the downstream sector,
the government has removed and, in some cases, minimised subsidy on petroleum products. It is noteworthy that these ‘executive actions’ are presently not backed by any regulation or legislation.

As indicated earlier, LNG is one aspect of the midstream sector that has continued to record progress, having successfully developed six operational LNG trains with the development of train seven in progress. Underpinned by the Nigerian Gas Master Plan (NGMP), Nigeria is set to experience significant growth in the largely untapped gas sector and consequently in the power sector – now fully privatised and estimated to have the potential to consume 36tcf of gas annually. In recent times, there has also been an increased drive to build gas markets in Nigeria, which is propelled by the approval of the Nigeria National Gas Policy. As stated in the policy, the intention of the government is for natural gas exports to continue; however, it will be consistent with Nigeria’s aspiration for domestic gas market development. In addition, renewal of licences and leases will be subject to a commitment by the licensee or lessee to the development of the discovered gas resources within the licence or lease area for domestic or export projects, as applicable, and within a specified time frame.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The legal framework regulating the oil and gas sector in Nigeria covers a broad range of legislation. The bedrock of the legislation is the Constitution of the Federal Republic of Nigeria, which vests ownership of mineral resources, including oil and gas, exclusively in the federal government and further confers on the federal government exclusive powers to make laws and regulations for the governance of the industry.

Key legislation includes:

a the Petroleum Act and the Schedules and Regulations made pursuant to it – providing the framework for the licensing of oil and gas companies to engage in activities connected with the exploration, production and transportation of crude oil;

b the Petroleum Profits Tax Act – providing the framework under which the federal government obtains revenue from oil and gas operations by way of signature bonuses, royalties and taxes;

c the Deep Offshore and Inland Basin Production Sharing Contracts Act – according tax relief incentives to oil and gas companies operating in the Deep Offshore and Inland Basin areas under PSCs;

d the Associated Gas (Reinjection) Act;

7 Petroleum Act Sections 2, 4 and 9.
8 Cap P 13, LFN 2004.
9 ibid., Sections 9, 20, 21–23, 56.
11 ibid., Sections 3, 4 and 5.
the Nigerian National Petroleum Corporation Act\(^\text{13}\) – establishing the NNPC and empowering it to participate directly in petroleum operations on behalf of the federal government;

- the Environmental Impact Assessment (EIA) Act\(^\text{14}\) – providing the framework for assessing the impact of oil and gas projects on the environment;\(^\text{15}\)

- the Federal Inland Revenue Service (FIRS) Establishment Act 2007 – detailing the statutory powers of the FIRS to collect all taxes, fees, levies, royalties, rents, signature bonuses, penalties for gas flaring, depot fees, including fees for oil prospecting licences, oil mining licences, etc.;\(^\text{16}\)

- the Education Tax Act\(^\text{17}\) – providing for the imposition of annual taxes at 2 per cent of assessable profits on oil and gas companies for the development of Nigeria’s educational sector;

- the Niger Delta Development Commission (Establishment) Act\(^\text{18}\) – requiring the payment to the Commission by oil and gas companies of 3 per cent of their annual budgets for the development of the Niger Delta from where oil and gas is exploited;\(^\text{19}\)

- the Nigerian Oil and Gas Industry Content Development Act 2010 – providing a framework for promoting participation of Nigerians in the industry and laying down minimum thresholds for Nigerian content utilised by the industry;\(^\text{20}\)

- the Nigerian Extractive Industries Transparency Initiative Act 2007 – providing the framework for transparency and accountability by imposing reporting and disclosure obligations on all oil and gas companies upon requirement by NEITI of revenue due to or paid to the federal government;\(^\text{21}\)

- the Oil Pipelines Act;\(^\text{22}\) and

- the Oil in Navigable Waters Act.\(^\text{23}\)

**Bill**

The Petroleum Industry Bill (PIB) is a potential game changer if enacted. The PIB aims to harmonise all the legislation in the oil and gas industry and significantly restructure the industry, particularly the functions of the various regulatory agencies, with a view to eliminating overlaps. To ease its enactment into law, the previous highest legislative house (eight Assembly) further unbundled the PIB into four smaller pieces of legislation delineated as follows:

- The Petroleum Industry Governance Bill (PIGB): This bill deals mainly with the governance and institutional framework for the petroleum industry;

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\(^{13}\) Cap N123, LFN 2004. See particularly, Sections 5, 6 and 10.

\(^{14}\) Cap E12, LFN 2004.

\(^{15}\) ibid., Section 2 and Paragraph 12 of its Schedule.

\(^{16}\) See FIRS Establishment Act, Sections 2, 25 and 68. Consider also Value Added Tax Act 2007, Section 10A(2) by which the oil and gas companies are obligated to charge and collect VAT and remit the same to the Federal Inland Revenue Service.

\(^{17}\) Cap E4, LFN 2004.

\(^{18}\) Cap N86, LFN 2004.

\(^{19}\) ibid, Section 14(b).

\(^{20}\) See particularly, NOGICD Act Sections 11 and 106.

\(^{21}\) See particularly, NEITI Act Section 3.

\(^{22}\) Cap O7, LFN 2004.

\(^{23}\) Cap O6, LFN 2004.
The Petroleum Industry Fiscal Bill: This seeks to establish a robust fiscal framework that ensures the development and exploitation of petroleum resources in a rational and sustainable manner;

The Petroleum Industry Administration Bill: The purport of this bill is to create a legal framework for the administration of upstream licences and leases; provide regulations for the organisation of the midstream operations and gas market and set out the procedures for administration of licensing and operations of the downstream; and

The Petroleum Host Community Bill: The bill provides a legal framework for cost and benefit share among the government, oil and gas companies and host communities.

iii Policies

In 2017, the Federal Executive Council approved the Nigerian Petroleum Policy (NPP) and the National Gas Policy (NGP). The overarching objectives of the NPP and the NGP is to set policy goals, strategies and an implementation plan for the introduction of an appropriate institutional, legal, regulatory and commercial framework to resolve the barriers currently affecting the petroleum sector and attract investment into the gas sector respectively. A third policy yet to be approved is the National Petroleum Fiscal Policy, which aims to provide a fiscal framework for Nigeria’s oil and gas industry.

iv Regulatory authorities

The Federal Ministry of Petroleum Resources has primary responsibility for policy direction and exercises supervisory oversight over the industry. The Minister of Petroleum Resources (the Minister) issues regulations, guidelines and directives pursuant to the Petroleum Act and other enabling laws. The Department of Petroleum Resources (DPR) is responsible for the day-to-day monitoring of the petroleum industry and for supervising all petroleum industry operations. Other regulators and agencies include: the Federal Ministry of the Environment (FME), NNPC, the NCDMB (Nigerian Content Development and Monitoring Board) and the National Oil Spill Detection and Response Agency (NOSDRA).

v Treaties

Nigeria is a signatory to the International Centre for Settlement of Investment Disputes Convention (ICSID). Where investment disputes arise between the government of Nigeria and a foreign investor and the parties are unable to come to a compromise as to the means of dispute resolution, in the absence of any bilateral or multilateral treaty between Nigeria and the investor’s country on dispute resolution, the applicable rules would be the ICSID Rules. Nigeria is also a signatory to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards 1958. On 16 May 2017, Nigeria ratified the Paris Climate Change Agreement and subsequently signed on to the Global Gas Flaring Partnership (GGFR) principles for global flare-out by 2030 while committing to a national flare-out target by 2020.

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24 See Petroleum Act, Sections 8 and 9.
25 See NIPC Act, Section 26(3).
Bilateral investment treaties with China (18 February 2010), Finland (20 March 2007), France (19 August 1991), Germany (20 September 2007), Italy (22 August 2005), Republic of Korea (1 February 1999), the Netherlands (1 February 1994), Romania (3 June 2005), Serbia (7 February 2003), South Africa (27 July 2005), Spain (19 January 2006), Sweden (1 December 2006), Switzerland (1 April 2003), Taiwan (7 April 1994) and the United Kingdom (11 December 1990) are in force while bilateral investment treaties with Algeria, Austria, Bulgaria, Canada, Egypt, Ethiopia, Jamaica, Kuwait, Morocco, the Russian Federation, Singapore, Turkey, Uganda and the United Arab Emirates have been signed and are awaiting ratification.

III LICENSING

The licensing regime under the Petroleum Act provides for the following licences.

i The oil exploration licence (OEL)

This is a non-exclusive licence that permits a licensee to explore for petroleum in the licence area. The OEL does not confer a right to an oil prospecting licence (OPL) or oil mining lease (OML). It is granted for one year and is renewable upon satisfaction of certain conditions.

ii The oil prospecting licence (OPL)

This grants the licensee the exclusive right to explore and prospect for petroleum and allows the licensee to carry away and dispose of petroleum won during prospecting operations subject to fulfilment of obligations imposed under the Act, by the Petroleum Profits Tax Act or other law imposing tax on petroleum. The duration is determined by the Minister and for onshore areas and shallow waters is five years, inclusive of any period of renewal, while an OPL for Deep Offshore and Inland Basins is 10 years.

iii The oil mining lease (OML)

This is granted only to the holder of an OPL upon satisfaction of all conditions of the licence or the Act and having discovered oil in commercial quantity (currently defined as a flow rate of 10,000bpd). The lease confers on the holder the exclusive right to search for, win, work, carry away and dispose of petroleum within the specified acreage for a period of 20 years. This may be renewed subject to the fulfilment of prescribed conditions.

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28 ibid.
29 Paragraph 3, First Schedule to the Petroleum Act.
30 Paragraph 7, ibid.
32 Paragraph 6, First Schedule to the Petroleum Act.
33 Section 2, Deep Offshore and Inland Basins Production Sharing Contracts Act.
IV PRODUCTION RESTRICTIONS

i Production

Restrictions on the production of oil and gas in Nigeria are as contained in the OPEC’s annual production allocations. Nigeria became a member of OPEC in 1971 and has since then been bound to comply with production restrictions imposed on each member country. Nigeria’s OPEC crude oil production allocation has fluctuated between 1.3 million bpd\(^{34}\) and 2.5 million bpd\(^{35}\) since the 1980s. Subject to the restrictions mentioned, parties to any exploration and production arrangements are entitled to lift their portion of production provided that they meet all their tax and royalty obligations.

ii Restriction on exports

The Ministry of Commerce has primary responsibility for issuing export permits, including permits for the export of petroleum products. There are generally no restrictions on exports for oil. However, the National Domestic Gas Supply and Pricing Regulations 2008 introduced restrictions on gas exports as it requires every producer to allocate a specific volume of its gas production to domestic utilisation. This is known as the domestic gas supply obligations (DGSO). DGSO volumes are set by the Minister.

iii Sale of production (crude oil) into the Nigerian market

An oil marketing company seeking to market Nigerian crude must first obtain a crude oil licence (COL). The NNPC Guidelines for Lifting of Nigerian Crude 2003 (the Guidelines) lays down the procedure and requirements for obtaining the COL. The company is required under the Guidelines to submit an application (accompanied by its audited accounts for the last three years, date of establishment, facilities, major markets, volumes traded in the last three years, number of employees, company objectives, other relevant information) to the NNPC. The company must also meet the following requirements to be eligible to apply:

\(a\) have a minimum annual turnover of US$100 million and a net worth of at least US$40 million;

\(b\) own a refinery or sales outlet;

\(c\) be an established and globally recognised oil and gas marketer with evidence of operations and of volumes of crude handled in the last three years; and

\(d\) provide a US$1 million performance bond, among other contractual arrangements.

Shortlisted applicants are considered on the basis of successful economic intelligence reports in respect of the outlined requirements, following which they may be granted the COL and awarded a crude oil allocation contract that entitles them to lift crude, sell to refineries, refine for export or refine for sale of refined products into the Nigerian market.

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34 OPEC, Annual Statistical Bulletin 2013, p. 10.
35 Member Countries’ Crude Oil Production Allocations, Available from www.opec.org/opec_web/static_files_project/media/downloads/data_graphs/ProductionLevels.pdf.
iv Price setting
The price at which crude oil is sold in Nigeria is unregulated. The NNPC is, however, responsible for setting the price for federal government crude. This price is known as the official selling price. The NNPC uses the Dated Brent-Forties-Oseburg-Ekofisk crude grade as a marker to determine the prices for the different grades of Nigerian crude.

V ASSIGNMENTS OF INTERESTS
i Right to assign
The holder of an OPL or OML may assign his or her interests to other persons either in part or whole, subject to the consent of the Minister. The Act specifically provides that 'without the prior consent of the Minister, the holder of an oil prospecting licence or oil mining lease shall not assign his licence or lease, or any right, power or interest therein or thereunder'. The Regulations include the word ‘takeover’ in addition to an ‘assignment’, with reference to applications to the Minister for the ‘assignment or takeover’ of an OPL or OML. Until recently there was controversy as to whether the Minister’s consent was required for the indirect transfer (via a corporate restructure) of petroleum interest; however, a court of first instance decided that these transfers require the Minister’s consent. The decision has been appealed, and this position is not settled under current legislation. However, the PIB is attempting to resolve this confusion by providing that a takeover, merger or acquisition, including a change of control of a parent company outside Nigeria, shall be deemed an assignment within Nigeria and shall require the Minister’s consent.

Other than the foregoing, the Petroleum Act allows the government to acquire interests in any licence or lease upon paying adequate compensation to the licensee or leaseholder.

ii Application for assignment
An application for the assignment of a licence or lease or interest in such licence or lease is made in writing to the Minister, accompanied by fees prescribed by the Minister and all other prescribed information in respect of the assignee and on such terms as the Minister may decide. The Minister may decline consent where he or she is not satisfied that the proposed assignee is of good reputation, has the required technical and financial capacity to effectively carry out its obligations and in all other respects, is acceptable to the federal government.

36 First Schedule, Paragraph 14, Petroleum Act and Regulation 4 of the Petroleum (Drilling and Production) Regulations (the Regulations).
37 Regulation 4(b) of the Regulations.
39 See PIB, Section 194(1) and (2).
41 Section 16, Petroleum Act.
**III Challenges**  
The major challenge with respect to assignment of interest is a lack of clear guidelines for the exercise of the Minister’s discretion, which has led to some measure of arbitrariness and uncertainty. A notable example of inadequate guidelines is the absence of any timeline for the exercise of the Minister’s powers to grant consent or otherwise.

**VI TAX**

The principal Act governing the taxation of petroleum operations in the upstream sector in Nigeria is the Petroleum Profit Tax Act (PPTA) as amended. Downstream gas operations are taxed under the Companies Income Tax Act.  

**i Highlights of fiscal provisions under the PPTA**

Current rates under the PPTA are as follows:

- **a** 85 per cent on onshore operations (but 65.75 per cent of the chargeable profits for the first five accounting periods of a new company);
- **b** 50 per cent on offshore operations in territorial waters and continental shelf area up to and including 1,000m water depth;
- **c** 50 per cent investment tax credit (ITC) for PSC signed before 1999. Companies operating under a PSC with NNPC can claim ITC as an offset against tax in accordance with the provisions of the PSC. The ITC rate applicable to the contract area shall be 50 per cent flat of the chargeable profit for the duration of the PSC, and
- **d** 50 per cent investment tax allowance for contracts signed post-1999.

**ii Petroleum investment allowance rates**

The following petroleum investment allowance rates applicable are:

- **a** onshore operations – 5 per cent;
- **b** operations in territorial waters and continental shelf area up to and including 100m water depth – 10 per cent;
- **c** operations in territorial waters and continental shelf area between 100m and 200m of water depth – 15 per cent; and
- **d** operations in territorial waters and continental shelf area beyond 200m of water depth – 20 per cent.

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44 Section 21(2) PPTA.  
45 Section 22(1) PPTA.  
46 Section 22(2) PPTA.  
47 Paragraph 4 and Table II of 2nd Schedule of PPTA.
iii Other applicable taxes

The NDDC\textsuperscript{48} tax requires the payment to the Commission of 3 per cent of the total annual budget of any oil-producing company operating, onshore and offshore, in the Niger Delta Area; including gas processing companies for the development of the region.\textsuperscript{49} The Education Tax Act provides for the imposition of annual taxes at 2 per cent of assessable profits on oil and gas companies for the development of Nigeria’s educational sector. Royalty is also charged at a graduated rate of zero per cent in areas beyond 1,000 metres water depth to 20 per cent in onshore areas of operations The National Petroleum Fiscal Policy provides a flat royalty rate of 5 per cent to small fields. Royalties can be paid in cash or by delivery of an equivalent volume of petroleum.

iv Tax authority

The Board of Inland Revenue\textsuperscript{50} of the Federal Inland Revenue Service is the policymaking body that administers matters of federal tax and has exclusive jurisdiction over petroleum taxation in Nigeria.\textsuperscript{51}

v Incentives applicable to the gas sector

Section 11 of the PPTA sets out provisions as to the incentives available for utilisation of associated gas. Although the primary purpose of these incentives is to encourage companies already carrying out petroleum operations to utilise rather than flare the associated gas encountered in the course of oil production, these incentives are also applicable to non-associated gas-utilisation\textsuperscript{52} projects. The incentives\textsuperscript{53} are allowable expenses for upstream operations (investment for separating crude oil and gas from a reservoir into usable products are treated as part of oil field development and therefore treated as an allowable expense); and investment in gas infrastructure (treatment of capital investment on facilities equipment to deliver gas in usable form as part of capital investment for oil development, therefore, is tax deductible).

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

There are several laws and regulations that prescribe standards and measures to be taken by operators in the industry to prevent and control pollution incidental to petroleum operations. These laws prescribe penalties for defaulters such as fines, terms of imprisonment and damages. Some of these laws also establish specialist agencies with primary responsibility for monitoring and enforcing environmental policies. In addition, the Minister is empowered to make regulations from time to time for the prevention of pollution\textsuperscript{54} from petroleum operations. Key laws and regulations are:

a the Mineral Oils (Safety) Regulations;
b the Oil in Navigable Waters Act;

\textsuperscript{48} The Niger Delta Development Commission.
\textsuperscript{49} See Section 14(b) NDDC Act.
\textsuperscript{50} Established and constituted in accordance with Section 1 of the Corporate Income Tax; See Section 2 PPTA.
\textsuperscript{51} The jurisdiction covers Nigerian territorial waters, continental shelf and Exclusive Economic Zone (EEZ).
\textsuperscript{52} Section 12 of the PPTA.
\textsuperscript{53} Subsection 2 further provides for conditions for the incentives.
\textsuperscript{54} Section 9(1)(b)(iii) of the Petroleum Act.
the Oil Pipelines Act;
the Environmental Guidelines and Standards for the Petroleum Industry (EGASPIN);
the Petroleum Refining Regulations;
the National Oil Spill Detection and Response Agency (Establishment) Act;
the Environmental Impact Assessment Act;
the Associated Gas Re-Injection Act;
the Harmful Waste (Special Criminal Provisions, etc.) Act;55 and
the Flare Gas (Prevention of Waste and Pollution) Regulations 2018.

Regulatory agencies with responsibility for environmental regulation are the DPR, the FME and the NOSDRA. The DPR sets standards for environmental safety and good oilfield practices in the industry, monitors and enforces compliance of industry operators while the FME is responsible for the regulation and administration of the environment including administering EIAs relating to oil and gas projects. The NOSDRA carries out surveillance on oil exploration to ensure compliance with all existing environmental legislation, particularly in the detection of oil spills and responding to such situations.

### Key environmental approvals necessary for the oil and gas activities

Some environmental approvals necessary for oil and gas activities include:

- **the EIA:** This is a mandatory prerequisite for operations in the upstream sector of the petroleum industry.56 In conjunction with the DPR, the FME is responsible for the approval of EIA reports that must be prepared by project proponents or initiators;
- **licences and permits:** Operators are required to obtain the necessary permits from the DPR for all aspects of oil-related effluent discharges from point sources (gaseous, liquid and solid), and oil-related project development; and
- **the Minister’s approval:** The approval of the Minister is specifically required for certain activities, for instance, decommissioning projects and gas flaring57 (where the Minister is satisfied that utilisation or reinjection is not appropriate or feasible in a particular field or fields).58

### Legal framework for decommissioning

The primary legislation governing decommissioning in Nigeria is the Petroleum Act and the Petroleum (Drilling and Production) Regulations made pursuant to the Act. The written permission of the Director of Petroleum Resources is required for the decommissioning of oil wells.59 The dumping of harmful waste from decommissioned material is a criminal offence punishable under the Harmful Waste (Special Criminal Provisions, etc.) Act. Nigeria is signatory to some international conventions creating certain obligations with respect to decommissioning. These include:

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56 Sections 4, 21 and 24 of the EIA Act.
57 Under the Environmental Regulations WEF 1 January 1984, pursuant to the Associated Gas Reinjection Act, 1979.
58 Section 3 of the Associated Gas Reinjection Act, 1979.
59 Article 36 of the Petroleum (Drilling and Production) Regulations, Article 32 of the Petroleum Refining Regulation.
a the Geneva Convention on the Continental Shelf 1958 (the Geneva Convention);60
b the United Nations Convention on the Law of the Sea 1982 (UNCLOS); and
c the London Dumping Convention 1972.

EGASPIN (2002)61 also introduces new offshore decommissioning provisions that mirror the International Maritime Organisation 1989 guidelines (i.e., that oil platforms sited in less than 100m water depth and weighing less than 4,000 tonnes (excluding the deck and superstructure) must be completely removed and after 1 January 2003 and that no installation can be placed on the Nigerian Continental Shelf or Exclusive Economic Zone unless it is designed for complete removal).

Contractual decommissioning responsibilities for offshore assets are also provided for in the 2000 and 2005 model production sharing contracts (PSCs). These PSCs provide for a fund for decommissioning purposes. In the 2005 PSCs the responsibility for decommissioning rests with the international oil company. However, the 1993 PSCs do not provide for offshore decommissioning and these are the operative PSCs in Nigeria.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The Companies and Allied Matters Act62 (CAMA) provides that, except for companies exempt from local registration, any foreign investor that intends to carry out business in Nigeria must incorporate a Nigerian entity.63 Furthermore, the Petroleum Act does not envisage the grant of licences to foreign registered companies, and in practice, no licence has been awarded to such companies. Accordingly, it is safe to conclude that only a Nigeria-registered company can be granted a licence to carry out oil and gas business in Nigeria.

Timing and procedure for the establishment of a Nigerian company

The procedure for establishment of a Nigerian entity for the purposes of oil and gas operations is as follows:

a incorporation of the entity with the Corporate Affairs Commission;
b registration of the company’s tax obligations with the FIRS;
c registration with the Nigerian Investment Promotion Commission (NIPC)64 (for companies with foreign participation); and
d registration with the DPR for a permit. Permits are granted in the general, major or specialised categories depending on the nature of services the entity intends to carry on in the industry.

The process for establishing a Nigerian entity and making the vehicle operationally ready will take an average of three to four months subject to the availability of the required information and supporting documentation as requested by the relevant agencies.

60 Geneva Convention on the Continental Shelf, Article 5.
61 EGASPIN, 327.
62 Cap C20, LFN 2004.
63 Section 54(1), CAMA.
64 Section 20 NIPPC Act, Cap N117, LFN 2004.
ii Capital, labour and content restrictions

A company investing or doing business in Nigeria may import capital for these purposes. The Nigerian Investment Promotion Commission (NIPC) Act\(^{65}\) and the Foreign Exchange (Monitoring and Miscellaneous Provisions) (FOREX) Act\(^{66}\) allows a party to do so through an authorised dealer (i.e., a commercial bank so designated by the Central Bank of Nigeria), in currency that is convertible into naira at the official foreign exchange market.

**Employment of expatriate personnel by a Nigerian company**

Under Nigerian law, priority is given to employment of Nigerian workers. However, where it can be shown that there are no qualified Nigerians to occupy a position, a company may employ expatriates to fill those positions. In order to qualify for an expatriate quota, a company must have a minimum share capital of 10 million naira.

**Nigerian content**

The Nigerian Oil and Gas Industry Content Development Act 2010 (the Local Content Act) sets out the framework to ensure the participation of Nigerians in the petroleum industry. For the purpose of Nigerian content, the Local Content Act defines a Nigerian company as one registered in accordance with the CAMA with a minimum of 51 per cent equity held by Nigerians. Other salient points to note on local content include:

\(a\) Nigerian independent operators shall be given first consideration in the award of licences in all projects for which contracts are to be awarded;\(^{67}\)

\(b\) compliance with the provisions of the Act and promotion of Nigerian content development is a major criterion for the award of licences, permits and interests in the industry;\(^{68}\)

\(c\) first consideration is to be given to services provided by Nigerians and to goods manufactured in Nigeria. Nigerians are also to be given first consideration for training and employment;\(^{69}\)

\(d\) operators are required to submit a Nigerian content plan demonstrating compliance with the requirements of the Act;\(^{70}\) and

\(e\) entities operating within the industry are to retain the services of Nigerian legal practitioners or a firm of practitioners with offices in Nigeria.\(^{71}\)

iii Anti-corruption

Efforts to curb corruption in the Nigerian oil and gas industry led to the establishment of the Nigerian Extractive Industries Transparency Initiative (NEITI) in 2004. NEITI, under its enabling law\(^{72}\) is charged with the task of promoting transparency and accountability in the management of Nigeria’s oil, gas and mining revenues, to engender due process, and ensure accurate reporting and disclosure by all extractive industry companies of revenues

\(65\) Sections 20, 21, and 24, NIPC Act.


\(67\) Section 3(1), Local Content Act.

\(68\) Section 3(3), ibid.

\(69\) Section 10(1), ibid.

\(70\) Section 7, ibid.

\(71\) Section 51(1), ibid.

\(72\) The NEITI Act 2007.
due to or paid to the federal government. Its governing body, the National Stakeholders Working Group (NSWG) is responsible for policy formulation, programmes and strategies to implement the NEITI’s mandate.

Nigeria also has the Freedom of Information Act 2011, which compels public officials to furnish information on matters of public interest at the request of any member of the public, the Economic and Financial Crime Commission Act, the Independent Corrupt Practices Commission Act, the Money Laundering (Prohibition) Act and other anti-corruption legislation.

IX CURRENT DEVELOPMENTS

i Flare gas commercialisation

Pursuant to the objectives of the Nigerian Gas Flare Commercialisation Programme (NGFCP) and the provisions of the Flare Gas (Prevention of Waste and Pollution) Regulations, 2018, which is to ultimately ensure a national gas phase-out by year 2020 to facilitate the optimisation of gas use in Nigeria, the government announced the first bid round for the gas flare commercialisation process in 2019. In addition, the DPR issued four guidelines outlined as follows:

a Guidelines for Grant of Permit to Access Flare Gas: These seek to provide direction for the competitive bidding process to be conducted by the federal government and set the criteria for granting permits to access flare gas to Nigeria-registered companies to enable them take flare gas at any flare site on behalf of the Nigerian government;

b Guidelines for Flare Payments: The Guidelines define the accounting procedure for flare payments for the producer at production facilities in respect of flared and vented gas.

c Guidelines for Flare Gas Measurement, Data Management and Reporting Obligations: These stipulate the general procedures for putting in place a gas flaring and venting accountability system in Nigeria, which includes, among others, data measurement, accounting, registration and reporting; and

d Guidelines for Producer’s Associated Gas Utilisation Project: These set out the process applicable for granting permits to access flare gas to producers for producers’ approved flare out projects in order to take flare gas at any flare site on behalf of the Nigerian government.

ii Petroleum Industry Bill (PIB)

With the dissolution of the eight Assembly following the end of its tenure, the passage of the age-long PIB discussed earlier, which is set to provide an all-encompassing legal and regulatory framework for the Nigerian petroleum industry and attract more investment into the country, suffered yet another major setback. The eighth Assembly had disaggregated the PIB into four smaller pieces of legislation to expedite its passage and in fact passed the PIGB, one of the smaller pieces of legislation before the end of its tenure. Notwithstanding the foregoing, the nation is optimistic that the ninth Assembly will accelerate the passage of the PIB with priority given to the PIGB as promised by its President.
I INTRODUCTION

Production of oil and gas on the Norwegian continental shelf (NCS) commenced in the 1970s following the discovery of the Ekofisk field. In the subsequent years, several additional large discoveries were made, and these fields have been, and still are, very important to the development of the activities on the NCS, also enabling the tie-in of a number of smaller fields. The Norwegian government has over the past 20 years introduced various adjustments in the legal (including fiscal) regime to attract new players to the NCS, and today almost 50 foreign and Norwegian companies are active on the NCS.

The petroleum resources are vested in the Norwegian state, and a sophisticated licensing system with mandatory participation in an unincorporated joint venture with standard joint operating agreement and accounting agreement enable private and state-owned companies to explore, develop, and produce petroleum in accordance with the principles laid down in licences and applicable acts and regulations. The main principle of Norway’s management of its petroleum resources is that exploration, development and production must be carried out in a prudent manner with the aim to maximise value creation for the society, and that revenues must accrue to the Norwegian state and thus benefit society as a whole. In 2018, 53 exploration wells were spudded on the NCS and 12 discoveries were made. Most of the new discoveries are small and near existing or planned infrastructure. At total of 83 fields were in production while 14 fields were under development by the end of 2018. In addition, nine plans for new developments (PDOs) were approved by the authorities during 2018.

In 2018, the total production of oil and gas (condensate and natural liquid gas included) reached approximately 227 million Sm³ of marketable petroleum. The Norwegian Petroleum Directorate (NPD) estimates that the overall production from the NCS will decline slightly in 2019 and then increase again during the period 2020–2023. The highest increase in production is expected in 2020, as a consequence of the major Johan Sverdrup fields commencement of production. For more information about the Johan Sverdrup field, see Section IX.

Norway supplies about 2 per cent of the global oil consumption. Gas production remained high in 2018, at about the same level as in 2017. Gas sales totalled 120 billion Sm³ in 2018. The growing demand for natural gas in other parts of Europe is an important explanation for this rise. In 2018, natural gas accounted for almost 50 per cent of total production by oil equivalents. The NPD’s estimate for total proven and unproven petroleum resources on the NCS is about 15.6 billion standard cubic metres of oil equivalents. Of this, 45 per cent has been sold and delivered.

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Norway is Europe’s second-largest oil producer (after Russia), the world’s third-largest natural gas exporter and an important supplier of both oil and natural gas to other European countries. The petroleum industry is by far the largest industry in Norway. Numbers published by Statistics Norway shows that total oil and gas investments on the NCS, excluding exploration, is expected to reach over 140 billion kroner in 2019, while the export value of crude oil and natural gas was about 442 billion kroner in 2018.

The oil and gas sector is Norway’s largest measured in terms of value added, government revenues, investment and export value. In 2018, the export value of crude oil, condensate and natural gas was about 442 billion Norwegian kroner. This makes oil and gas the most important export contributor in the Norwegian economy. The Norwegian government’s total net cash flow from petroleum activities, including the dividend from Equinor (formerly Statoil) and various fees, is estimated to approximately 263 billion kroner in 2019. This represents a significant increase in revenues compared to the last four years, mainly because of higher oil and gas prices. The state’s income from the petroleum sector is transferred to a separate fund; the Government Pension Fund – Global. By 10 September 2019, the fund was valued at approximately 9,600 billion kroner.

II LEGAL AND REGULATORY FRAMEWORK

The main statute relevant for petroleum activities is the Petroleum Act No. 72 of 29 November 1996 (the Petroleum Act) while the more detailed rules are set out in various regulations, including the following pertaining to resource management:

\( a \) the Petroleum Regulations No. 653 of 27 June 1997 (the Petroleum Regulations);

\( b \) the Resource Management Regulations No. 749 of 18 June 2001;

\( c \) the Regulations Relating to the Use of Facilities by Others No. 1625 of 20 December 2005; and

\( d \) the Regulations Relating to the Stipulation of Tariffs, etc. No. 1724 for Certain Facilities of 20 December 2002 (the Tariff Regulations).

In addition, there are various regulations relating to health, safety and environment, elaborated on in Section VII.

The Petroleum Taxation Act No. 35 of 13 June 1975 (the Petroleum Taxation Act) is also considered a core statute governing taxation of exploration, production and extraction of sub-sea petroleum deposits. Four of the most relevant appurtenant regulations are:

\( a \) the Regulations on Petroleum Taxation No. 316 of 30 April 1993;

\( b \) the Regulations Relating to Consent to the Transfer of Licence and Ownership Interests According to the Petroleum Taxation Act Section 10 of 1 July 2009 No. 956;

\( c \) the Regulations Relating to Taxation on Rental of Moveable Production Facilities No. 819 of 18 August 1998; and

\( d \) the Regulations for Determining the Norm Price No. 5 of 25 June 1976 (the Norm Price Regulations).

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2 Sources: Resource- and production numbers are quoted from the website for Norwegian Petroleum, cf. www.norskpetroleum.no, the Norwegian Petroleum Directorate (www.npd.no) and Statistics Norway (www.ssb.no).

3 Source: Norges Bank – Investment Management, see www.nbim.no.
Domestic oil and gas legislation

The Petroleum Act provides the general legal basis for petroleum activities on the NCS. According to the Act and the Petroleum Regulations, licences can be awarded for exploration, production and transport of petroleum, meaning that the proprietary right to the petroleum deposits on the NCS is vested in the state. Official approvals and permits are necessary in all phases of the petroleum activities, from award of exploration and production licences, in connection with the acquisition of seismic data and exploration drilling, to plans for development and operation, production and decommissioning.

Prior to awarding production licences, an impact assessment must be carried out to evaluate factors such as the economic and social effects, and the environmental impact the activity could have for other industries and the adjacent districts in the relevant areas. The impact assessment and opening of new areas are governed by Chapter 3 of the Petroleum Act and Chapter 2a of the Petroleum Regulations.

Production licences are awarded through licensing rounds announced by the Ministry of Petroleum and Energy (MPE). The announcement is made official on, inter alia, the NPD’s website (www.npd.no).

The production licence regulates the rights and obligations of the companies in relation to the Norwegian state. The licence supplements the requirements in the Petroleum Act and stipulates detailed terms and conditions. The licensees become the owners of the petroleum that is produced. More detailed provisions regarding the licensing regime and production licences can be found in Chapter 3 of the Petroleum Act and the Petroleum Regulations.

If the companies find it commercially viable to develop a field, they are required to carry out prudent development and operation of proven petroleum deposits. When a new deposit is to be developed, the company must submit a plan for development and operation to the MPE for approval. An important part of that plan is to perform an impact assessment that is submitted for consultation to various bodies that could be affected by the specific field development. Development and operation is governed in more detail by Chapter 4 of the Petroleum Act and the Petroleum Regulations.

As a general rule, the Petroleum Act requires licensees to submit a decommissioning plan to the MPE two to five years before the licence expires or is relinquished, or before the use of a facility ceases. Decommissioning or disposal of facilities is governed by Chapter 5 of the Petroleum Act and Chapter 6 of the Petroleum Regulations.

Liability for damages resulting from pollution is governed by Chapter 7 of the Petroleum Act. The licensees are responsible for such damage without regard to fault.

Safety aspects associated with the petroleum activities are governed by Chapters 9 and 10 of the Petroleum Act, with appurtenant HSE regulations. The petroleum activities shall be conducted in a prudent manner to ensure that a high level of HSE can be maintained and developed throughout all phases, in line with the continuous technological and organisational development.

The Norwegian state participates directly in the petroleum activities through the state’s direct financial interest (SDFI) managed by the wholly state-owned company Petoro AS (Petoro). Detailed rules governing the management of the SDFI are laid out in the Petroleum Act Chapter 11.
ii Regulation

The main governmental offices responsible for petroleum activities on the NCS are the MPE, the Ministry of Finance (MoF), the Ministry of Labour and Social Affairs, the Ministry of Climate and Environment, and the Ministry of Trade, Industry and Fisheries.

The MPE has the overarching responsibility for managing the petroleum resources and is also responsible for the state-owned companies Petoro and Gassco AS. Gassco is the operator for the integrated pipeline system for transporting gas from the NCS to other European countries. The NPD is subordinated to the MPE and its paramount objective is to make sure that the resource management of the Norwegian petroleum resources are conducted in a best possible manner.

The MoF has the main responsibility of ensuring that the state collects the applicable taxes and fees from the petroleum activities, including corporate tax, special tax, CO₂ tax and NOₓ tax. The Petroleum Taxation Office is part of the Norwegian Tax Administration, reporting directly to the MoF, and is responsible for ensuring correct levying and payment of taxes and fees adopted by the political authorities.

Moreover, the Petroleum Safety Authority (PSA), under the Ministry of Labour and Social Affairs, has the regulatory responsibility for technical and operational safety, including emergency preparedness and working environment in petroleum activities.

The Norwegian Environment Agency, under the Ministry of Climate and Environment, is responsible for all environmental issues pertaining to the petroleum activities, such as granting the requested permissions to pollute.

Another governmental body involved is the Norwegian Coastal Administration, under the Ministry of Transport, and is responsible for the state’s oil spill preparedness.

Finally, the Norwegian Maritime Authority (NMA) is the administrative and supervisory authority in matters related to safety of life, health, material values and the environment on maritime vessels involved in the petroleum activities. The NMA is among others issuing certificates/LOC to mobile drilling units used in the petroleum activities, and is also following up if such units are in compliance with the applicable maritime regulations. The NMA has entered into a cooperation agreement with the PSA, dividing responsibility as to the follow-up of mobile offshore units. The NMA is subordinate to the Ministry of Transport.

iii Treaties

Norway is a contracting state to both the New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Lugano Convention on Jurisdiction and the Recognition and Enforcement of Judgments in Civil and Commercial Matters. Further, Norway is a party to bilateral investment protection treaties entered into with different states regarding mutual promotion and protection of investments. The Agreement on the European Economic Area (EEA) and the TRIMs (Trade-Related Investment Measures), TRIPS (Trade-Related Aspects of Intellectual Property Rights) and GATS (General Agreement on Trade in Services) agreements (treaties of the World Trade Organization), to which Norway is a party, are considered bilateral investment treaties. An example of a multilateral treaty ratified by Norway is the cooperation agreement between Member States of the European Free Trade Association and the European Investment Bank.

Double taxation relief is available in accordance with double taxation treaties (DTTs), entered into between Norway and several foreign states. The DTTs are mostly based on
various editions of the OECD Model Tax Convention on Income and on Capital, or the UN Model Tax Convention in case of DTTs entered into between Norway and typical developing countries.

Since 1992, Norway has been practising what is referred to as the ‘credit system’. Under the credit system, income derived from a foreign source is considered liable to tax in Norway, but the taxpayer is credited a tax relief based on taxes paid in the state of source. Credit is normally limited to the rate of Norwegian tax levied on the foreign income. Following introduction of the credit system, many of the older double tax treaties that have been based on the exemption method have either been or are currently under renegotiation.

Under Norwegian domestic tax law, relief from double taxation is either granted by way of a double tax credit or by deduction of the foreign tax from the Norwegian corporate tax basis.

### III LICENSING

There are two distinct licences that the MPE may grant: exploration licences and production licences. In addition, a specific licence to install and operate pipelines is also granted by the MPE. The exploration licence is not exclusive, and does not give a preferential right if a subsequent production licence is granted. A production licence is, on the other hand, exclusive, meaning the licensees are given a sole right to conduct surveys, exploration and production within the geographical area defined by the production licence. The award of a production licence is based upon the applicant’s technical expertise, financial strength, geological understanding and experience on the NCS or similar areas.

It should be noted that exploration and production licences are awarded separately, and that an exploration licence will not necessarily be awarded prior to a production licence. Exploration licences are granted for a period of three calendar years unless otherwise specifically stipulated in the licence. Production licences are granted for an initial period of up to 10 years, and if the licence is granted for a shorter period of time, the MPE may subsequently extend the licence period within the 10-year limit. When the licensees have fulfilled the mandatory work obligations set out in the production licence they may require a further extension of the production licence. A possible extension period is stipulated in the applicable production licence and shall as a general rule be up to 30 years, but may under specific circumstances be up to 50 years.

Production licences on the NCS are awarded following two different licensing rounds; areas regarded as mature are subject to an annual simplified licensing round referred to as awards in predefined areas (APA). On the other hand, areas that are not regarded as mature are subject to ordinary licensing rounds traditionally held every second year. Companies can apply individually or as a group. Based on the applications submitted, the production licences are awarded to a group of companies forming a joint venture on the basis of relevant, objective and non-discriminatory announced criteria. One of the licensees is further appointed as an operator.

Production licences can also be obtained through direct or indirect transfer of participating interests. Such transactions require the consent of both the MPE and the MoF (see the Petroleum Act Sections 10–12 and the Petroleum Taxation Act Section 10).
IV PRODUCTION RESTRICTIONS

Pursuant to the Petroleum Act the production of petroleum shall be conducted in the most cost-effective manner. The production schedule is subject to the prior approval of the MPE. There are, as a starting point, no restrictions on production entitlements or rights related to exports of oil and gas. The government is, however, provided with some special legal tools that may be used in times of crisis. First, if necessary owing to important interests of society, the government may stipulate production schedules other than those stipulated for one or several petroleum deposits. This legal tool also includes the right to reduce the production level. Second, in the event of national or worldwide difficulties in the supply of oil and gas, the licensees may be required to make deliveries of their production to cover national requirements and to provide transport to Norway. Furthermore, in the event or threat of war or other extraordinary crisis, the licensees may be required to place petroleum at the disposal of Norwegian authorities. The potential legal restrictions listed above are all to be considered as narrow safety nets, implying that the potential restrictions on production entitlements have only been utilised a few times since commencement of petroleum activities on the NCS.

The Norwegian Petroleum Price Council is, according to the Petroleum Taxation Act, Section 4, responsible for setting the norm prices, used in order to calculate the taxable income for the oil companies operating on the NCS. Determination of norm prices is based on the principle that it should reflect the price that could have been achieved between independent parties. The procedure for determining norm prices is governed by the Norm Price Regulations.

Where the Council does not find it reasonable to set norm prices, the actual price achieved will be used as the applicable tax reference price. Note that the norm price system is not applicable to taxation of dry gas sales. Such sales are insofar as the price reflects the market value taxed on the basis of the actual price achieved.

V ASSIGNMENTS OF INTERESTS

Transfer of assets in production licences is subject to the MPE’s prior consent (see the Petroleum Act Section 10-12). The requirement also applies to the purchase of at least one-third of the shares in a company holding a production licence or if the purchaser passes the thresholds of one half or two-thirds control of the company holding the production licence. Although the above thresholds are not exceeded, shareholder rights such as veto rights or the right to consent to certain activities under the Norwegian licence could easily trigger the need for consent under Section 10-12. A corresponding consent related to the tax consequences must, according to the Petroleum Taxation Act, also be obtained from the MoF. There are no requirements as to any specific consideration being made. The consequence of not obtaining a required consent under the Petroleum Act Section 10-12 is that the transaction may not be completed.

It is not possible to provide an exact estimate of the time frame for obtaining approval from the MPE, as it may vary from days to many months. Factors that may influence the process are, inter alia, whether the assignee is a company already established on the NCS, the complexity of the transaction and the financial situation of the assignee. In the majority of the transactions on the NCS, it takes more than three weeks to receive approval from the MPE.

If transferring licences in the development or production phase, the assignor is exposed to a potential secondary financial liability for decommissioning costs. The liability is limited to the assignor’s participating interest for installations existing at the field at the date the transfer is registered in the Norwegian Petroleum Register. For more information, see Section VII.
The Norwegian state has, through the SDFI, a pre-emption right in all production licences being transferred on the NCS. The pre-emption right is exercised through the wholly state-owned company, Petoro. The pre-emption right does not apply to transactions involving transfer of shares. The pre-emption right has never been exercised, but it may not be ruled out that it can still be utilised in the future.

VI  TAX

Petroleum activities on the NCS are governed by the Petroleum Taxation Act. The Act levies a special tax of 56 per cent in addition to the ordinary corporate tax rate of 22 per cent, leaving the marginal tax rate at 78 per cent. However, there is an uplift allowance when calculating the special tax. The uplift equals 5.2 per cent per year over a four-year period on capital investments, in total 20.8 per cent. The uplift was introduced to ensure a regular rate on return on the capital investments.

All exploration costs may be deducted. For production facilities and pipelines governed by the Petroleum Act, a linear depreciation rate of 16.66 per cent per year is granted.

Oil and gas companies operating on the NCS with no taxable surplus may carry forward their losses and their uplift allowance included interest. The interest rate is set annually by the MoF. The right to carry forward such losses is for an indefinite time period.

Consolidation between the different fields on the NCS is permitted, and the companies may use taxable surplus obtained from one field and settle this against losses incurred from activities on another field on the NCS.

Owing to a special provision in the Petroleum Taxation Act, companies that are in a tax loss position may annually claim a cash reimbursement from the state equivalent to the fiscal value (78 per cent) of exploration costs that the company has carried during the income tax year. The legislation also allows the companies to pledge or sell such reimbursement claims against the state. In all, the right to claim reimbursement of exploration costs and the right to carry forward losses equivalent to the fiscal value is beneficial for operating companies without positive taxable income and that are in a start-up phase.

Other taxes and fees related to activities on the NCS include the CO₂ tax, which for 2019 is 1.08 kroner per litre of produced petroleum, the NOₓ tax and the area fee.

The MoF will provide its consent to any transfer of licences or participating interests in licences that comprise the Petroleum Act, Sections 10–12. The main objective is to ensure a neutral tax effect of the transactions.

VII  ENVIRONMENTAL IMPACT, HSE AND DECOMMISSIONING

The Norwegian Environment Agency manages and enforces the Pollution Control Act of 13 March 1981 No. 6, the Product Control Act of 11 June 1976 No. 79 and the Greenhouse Emission Trading Act of 17 December 2004 No. 99, and is responsible for granting permits, establishing requirements and setting emission limits. The overarching goal of the aforementioned acts is to protect the environment against pollution, including pollution from the petroleum industry. In addition, various EU directives related to the environment have also been implemented in Norwegian law, and must in this case be complied with when conducting offshore petroleum activities covered by the relevant legislation. Breach of the regulations enforced by the Norwegian Environment Agency may lead to administrative and criminal sanctions.
The PSA is the administrative body responsible for technical and operational safety, and the working environment related to offshore and onshore activities covered by the Petroleum Act. Said responsibility covers all phases of the relevant activities, including planning and design, construction and operation, and decommissioning and removal. All licensees conducting activities on the NCS shall have a management system that the PSA finds to be in compliance with the HSE regulations, and breach of the applicable regulations may be subject to administrative and criminal sanctions.

The main HSE requirements applicable to subsea and onshore activities forming an integrated part of the offshore petroleum production are set out in the following regulations:

- the Framework Regulations of 12 February 2010 No. 158;
- the Management Regulations of 29 April 2010 No. 611;
- the Facilities Regulations of 29 April 2010 No. 634;
- the Activities Regulations of 29 April 2010 No. 613; and
- the Technical and Operational Regulations of 29 April 2010 No. 612.

As a general rule, all mobile offshore drilling facilities, floating production, storage and offloading units (FPSOs), accommodation units and well intervention units registered in a national ship register are required to obtain an acknowledgment of compliance before commencement of petroleum activities. An exception is applicable to mobile facilities where the operator itself is responsible for the operations. The acknowledgment of compliance is provided by the PSA and expresses the authority’s confidence that petroleum activities can be carried out using the facility within the framework of the regulations. An applicant can either be the owner of the facility or a party in charge of the day-to-day activities of the facility. After receiving an AoC, the mobile offshore facility still need to comply with mandatory requirements in applicable Acts and regulations.

The main legal framework relating to decommissioning of oil and gas facilities and pipelines is included in the Petroleum Act Chapter 5 and the Petroleum Regulations Chapter 6. The licensees are obliged to submit a decommissioning plan to the MPE prior to expiry or surrender of a production licence or a specific licence referring to installation and operation of facilities, alternatively before the use of a facility is permanently terminated. The plan shall contain proposals for continued production or shutdown of production and disposal of facilities. The MPE renders a final decision relating to the content of and the time limit for implementation of the decommissioning plan. The decision shall, inter alia, be based on technical, safety, environmental and economic aspects as well as considerations to other users of the sea.

In addition to national regulations, the decommissioning plan must take into consideration various requirements undertaken in international treaties and conventions. This particularly relates to the OSPAR Decision 98/3 on the Disposal of Disused Offshore Installations, the Guidelines of the International Maritime Organization (IMO) and the United Nations Convention on the Law of the Sea (UNCLOS).

The MPE is entitled to request a parental guarantee or any other security from the licensee at any phase of the petroleum activities, which also means that specific security may be requested in connection with the conclusion of decommissioning activities. In practice, the MPE has until now only requested a standard parental guarantee when the company is pre-qualified as a licensee or is being awarded its first production licence.
If a licence or a participating interest thereof has been transferred, the assignor shall (inter partes) be secondarily liable for financial obligations towards the assignee and the remaining licensees for the costs of carrying out the decision relating to disposal (see the Petroleum Act Section 5-3 and the Petroleum Regulations, Section 45a).

The MPE has through a letter dated 8 November 2016 to the Norwegian Oil and Gas Association (No: Norsk Olje og Gass) announced that the secondary financial liability may also apply to indirect transfer of licences (share sales). The approach is that the MPE in connection with providing consent to the transfer (Petroleum Act Sections 10–12) shall consider whether to attach a condition stating that the assignor shall undertake a secondary financial liability for decommissioning costs related to his or her participating interests for installations existing at the field at the time the transfer is registered in the Petroleum Register. To ensure fulfilment of this potential secondary financial liability, the MPE may request that also the ultimate parent company of the assignor undertake the same obligation through a standard guarantee with both the Norwegian state and the licensees as the beneficiaries. The new practice has been in place since September 2017.

Normally, the assignor will request the assignee to provide a parental guarantee or bank guarantee in order to make sure that the assignor is indemnified in the event of being held liable for any upcoming decommissioning costs.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The MPE may grant an exploration licence to a body corporate irrespective of whether the company is domiciled or registered in Norway. Exploration licences may also be granted to physical persons domiciled in a state within the EEA. Production licences may be granted to a body corporate established in conformity with Norwegian legislation and registered in the Norwegian Register of Business Enterprises, and to physical persons domiciled within the area of the EEA. Pursuant to the EEA Agreement, companies applying for a production licence may also be established or domiciled in an EEA state.

According to the Petroleum Act, the licensees shall ensure that the activity on the NCS can be carried out prudently and in a manner that safeguards good resource management, health, safety and the environment. To ensure compliance with these requirements the MPE may, to the extent it is deemed necessary in relation to the scope of the licensee’s activity, set special requirements regarding the licensee’s organisation in Norway. The ministry may also, if indicated by the consideration for prudent resource management or health, safety and the environment, order the licensee to use specific bases. In practice, more or less all companies being awarded a production licence have been domiciled in Norway and registered as a company with limited liability within a reasonable period of time after the award.

When urgent, law firms will normally be able to incorporate and register a new company in the Register of Business Enterprises within 24 hours as long as all board members have a Norwegian identity number.

The minimum share capital is 30,000 kroner for a private limited liability company and 1 million kroner for a public limited liability company. At least 50 per cent of the board members in the company have to be EEA citizens residing in an EEA country.
The most common obstacle in incorporating and quickly registering a new company in Norway is obtaining Norwegian identity numbers for foreign board members who have not previously held any corporate positions in Norway. Obtaining these identity numbers normally takes two weeks.

ii Capital, labour and content restrictions

Except for common restrictions on the movement of physical bank notes, there are no particular restrictions on the movement of capital or access to foreign exchange. Note, however, that all cross-border transactions are reported to a central register.

In the private sector, hiring of employees is generally based on contractual freedom between the employer and the employee. However, certain details concerning the hiring process, such as the material content of the employment contract and term of notice, are regulated by the Norwegian Working Environment Act.

The employment may in addition to the Working Environment Act be regulated by collective bargaining agreements, depending on whether the company is bound by one or more such agreements. Several Norwegian collective bargaining agreements are applicable to the oil and gas sector, inter alia, pertaining to salary and working conditions. Regarding work permits, the Norwegian government differentiates between foreign workers from EEA countries and workers from other countries. Workers from EEA countries must register themselves to be able to work in Norway. Workers from other countries, however, will have to be categorised as skilled workers by the Norwegian Directorate of Immigrants to be granted a work permit. To qualify as a skilled worker, the employee must either have completed vocational training at upper secondary school level for at least three years (and there must be a corresponding vocational training programme in Norway), or the employee must have obtained a degree from a university or university college (e.g., a bachelor's degree as an engineer), or have qualifications obtained through work experience, if relevant in combination with courses, etc.

iii Anti-corruption

Corruption in general is criminalised in the Norwegian Penal Code and is defined as to request, receive, accept, give or offer an improper advantage to someone in connection with their position, office or assignment.

Public bodies and private entities may be found guilty of corruption if an employee has violated the Norwegian Penal Code while executing work for the employer.

In terms of what behaviour the code prohibits, the term ‘advantage’ is far-reaching, and may refer to any kind of payment, favour, commitment, etc. Furthermore, the Code does not require that the advantage has had any influence on any decisions or policies, or had any other negative effect in practice. Therefore, it is not necessary to prove that the entity or individual charged has gained from the corruption. The advantage need not be of an economic nature.

It is then the term ‘improper’ that defines which advantages amount to corruption. Admittedly the term is rather vague, and whether an advantage is defined as improper depends on the circumstances of the case. Public bodies and officials acting on behalf of public bodies will (as opposed to private individuals and undertakings) generally be subject to a stricter norm when assessing whether an advantage conferred or obtained is to be regarded as improper.
Although not characterised as corruption, the Penal Code criminalises ‘trading in influence’. Trading in influence refers to situations where a person gives or offers a middleman an improper advantage in return for exercising influence on the conduct of any position, office or assignment. If the middleman’s relationship with the giver and the intention behind attempting to exercise influence has been concealed, the behaviour is likely to be caught by the Penal Code.

Moreover, pursuant to Regulation of 26 June 2009 No. 856, all licensees are obliged to report payments made in relation to petroleum activities on the NCS. This Regulation accomplishes the criteria set out by the Extractive Industries Transparency Initiative (EITI) promoting revenue transparency and accountability in the extractive sector, including the oil and gas sector. For more information about EITI, see https://eiti.org/homepage.

IX CURRENT DEVELOPMENTS

The activity level on the NCS has increased since the dramatic drop in oil prices in 2014. Fifty-three exploration wells were spudded on the NCS and 12 discoveries made during 2018. Fourteen fields were under development, and a record number of nine new field development plans were approved by the authorities in 2018.4

The development of the Equinor-operated Johan Sverdrup field stands out as the project people in the industry are most enthusiastic about. The Plan for Operation and Development (PDO) was approved by the MPE in August 2015. The oil and gas production capacity for the full field is expected to be in the range of approximately 650,000 barrels of oil equivalent per day, and the operator expects that the total production from the field will be 2.7 billion barrels. Production in phase 1 is planned to start by the end of October 2019. The partners submitted the PDO for the second phase of the development in the end of August 2018. Phase 2 is currently scheduled to come on stream in the second half of 2022. The field is expected to be producing for approximately 50 years. This makes Johan Sverdrup one of the five largest fields ever discovered on the NCS.

One of the other giant development projects on the NCS is the Johan Castberg field located in the Barents Sea. The field discovered in 2011 is located 110 kilometres north of the Snøhvit field, and proven resources are estimated to be between 450 to 650 million barrels of oil. The development concept is a floating production, storage and offloading vessel (FPSO) with additional subsea features. The PDO was approved by the authorities in June 2018, and commencement of production is expected during fourth quarter of 2022. The field is scheduled to be producing for 30 years.

It is expected that major field developments such as Johan Sverdrup and Johan Castberg, many small and medium-sized discoveries in close proximity to existing infrastructure, and the government’s ‘green light’ for exploration and production activities in the very promising area in the south-east of the Barents Sea will ensure that the NCS continues to be one of the most prosperous petroleum provinces in the years to come.

The newly constructed Polarled pipeline has a total length of 482 kilometres and ties the Aasta Hansteen field in the Norwegian Sea to the Nyhamna gas processing facility in north-western Norway. Polarled is the first offshore pipeline crossing the Arctic Circle and is designed for a transport capacity for of approximately 70 million cubic metres of gas per

4 Sources: The Norwegian Petroleum Directorate (www.npd.no) and Norwegian Petroleum (www.norskpetroleum.no).
day. The pipeline expands the existing gas transport network on the NCS and facilitates for phasing in resources available in existing and future Norwegian Sea discoveries. Gassco is the operator of the Polarled pipeline, which received its first gas volumes when the Aasta Hansteen field came on stream in December 2018.

Access to third-party infrastructure is governed by two different regulations. Access to the gas transportation network (Gassled) is governed by Regulation 20 December 2002 relating to the stipulation of tariffs for certain facilities (the Tariff Regulations). Third-party access to other offshore infrastructure is governed by Regulations 20 December 2005 relating to the use of facilities by others (TPA-Regulations). The Tariff Regulations provides rules on regulated access with set tariffs, while access to infrastructure under the TPA-Regulations is based on negotiated terms within set criteria. The aim of both regulations is to ensure efficient use of existing infrastructure on the NCS, and the overriding principle is that only the owner shall be entitled to maximise profit through production and not in the transportation network and other infrastructure. The increased use of third-party facilities on the NCS is likely to give rise to more disputes related to the specific tariff level and other applicable terms and conditions under the TPA-Regulations.

Four of the stakeholders in Norway’s gas pipeline network (Gassled) have through a ruling by the Norwegian Supreme Court of 28 June 2018 lost a major case against the Norwegian state. The claimants also lost the case in the district court and the Court of Appeal, and this has been one of the most discussed disputes in the Norwegian petroleum sector during recent decades. The companies involved included the investors that acquired a total 44 per cent stake in Gassled from oil- and gas majors back in 2011 and 2012. In 2013 (after the acquisition was completed), the Norwegian government introduced changes in the Tariff Regulations implying a cut in Gassled tariffs by 90 per cent on future gas resources (effective as from 1 October 2016). Never before have changes to the legal framework with such significant negative economic impact to the owners of oil and gas infrastructure been introduced in Norway, but the alterations must be seen in light of the principle that the owners of the transportation network shall only have a ‘reasonable return’ on their investment while the main profit shall be allocated to the upstream activities. The new owners held that this reduction was unlawful, and claimed damages amounting to approximately 34 billion kroner, which, it was argued, represent the reduced tariff income during the period 2016 to 2028 (the end of the licence period). The Supreme Court held in its unanimous ruling that there was no legal basis to declare the reduction of the tariffs through the alterations to the Tariff Regulations invalid, and added that the outcome did not raise any doubt.

On 20 April 2019, the EFTA Surveillance Authority (ESA) provided its decision in a complaint case concerning the Norwegian Petroleum Taxation Act. Under the Norwegian Petroleum Taxation Act, companies with taxable income can deduct exploration costs, an indispensable phase of petroleum extraction. Petroleum companies that do not have taxable income can carry forward their losses with interest, or ask for an annual cash refund of the tax value of these costs.

The case was brought to ESA by Bellona, an environmental non-profit organisation, claiming that the cash refund of the tax value of petroleum exploration costs entails unlawful state aid from the Norwegian state by giving a selective advantage to certain companies.

ESA found that the annual cash refund of the tax value of petroleum exploration costs does not entail state aid. ESA concluded that the measure is not selective since it is available to all companies on an equal footing. According to EEA state aid rules, a measure that is not selective does not constitute state aid.
The annual tax refund has been very important to attract new companies to conduct exploration activities on the NCS, and ESA’s decision was applauded by the Norwegian petroleum industry.

In October 2016, the environmental groups Greenpeace and Natur og Ungdom sued the Norwegian state claiming that the decision of opening areas in the Arctic for oil and gas exploration was a breach of Article 112 of The Constitution of the Kingdom of Norway (the Constitution). The case was tried before Oslo District Court in November 2017, and the court ruled in favour of the state in its judgment of 4 January 2018.

The background for the lawsuit was the MPE’s decision to open up areas of the Arctic Ocean for oil and gas exploration, and to offer 13 oil companies 10 production licences in the 23rd licensing round (see further information above). The plaintiffs claimed that the Norwegian State by its decision had violated Article 112 of the Constitution, and that the decision thus was invalid. Article 112 of the Constitution has the following wording (unofficial English translation):

Every person has the right to an environment that is conducive to health and to a natural environment whose productivity and diversity are maintained. Natural resources shall be managed on the basis of comprehensive long-term considerations which will safeguard this right for future generations as well.

In order to safeguard their right in accordance with the foregoing paragraph, citizens are entitled to information on the state of the natural environment and on the effects of any encroachment on nature that is planned or carried out.

The authorities of the state shall take measures for the implementation of these principles.

Oslo District Court found that the MPE had implemented sufficient measures to safeguard the environment, and that the decision to open up the area for petroleum exploration was not in breach of the threshold established under Article 112 of the Constitution.

The judgment has been appealed to Borgarting Court of Appeal, and the new trial is scheduled to take place in November 2019.
INTRODUCTION

The first oil and gas exploration and production operations in Portugal were carried out in the early 20th century. In the 1970s, after drill stem tests produced small quantities of crude oil, several wells were drilled. However, Portugal’s petroleum potential – including its exclusive economic area – remains under-evaluated, with an average of 2.4 wells drilled per 1,000 square kilometres, and no proven reserves.

Major efforts in the 1970s and 1980s aimed to locate commercial reserves, following the ‘oil shocks’ of the time and the discovery of crude oil in the Grand Banks, of which the offshore areas of Portugal are considered a geological continuation. However, the results of these efforts were disappointing and the industry’s interest in the country declined.

In 1994, the government adopted new legislation in the sector, simplifying procedures and providing more favourable fiscal terms aimed at reigniting the interest of international companies and attracting new investment. In line with classical western European tradition, this legislation continued to follow the concession model, but instituted more flexible terms for the basic framework of contracts, namely:

- the definition of concession areas is based on a small unit (lot) measuring 6° longitude by 5° latitude, allowing the concessionaire to apply for the area it wants to explore, grouping these lots into ‘blocks’ of up to 16 contiguous lots;
- it extends the exploration period to 10 years;
- production rights, following the discovery and final delineation of an oilfield, are granted for at least 25 years, which can be extended to 40 years; and
- minimum exploration commitment requirements are of one well per block from the fourth year, with the rest being left for agreement in negotiations.

Deep offshore areas will not be subject to these terms until a specific regulation is published (which is not expected anytime soon), an incentive to attract companies interested in exploring these areas, which will enjoy even greater flexibility when submitting their proposals.

Shortly after the 1994 law was enacted, and to prepare for a public tender for the award of exploration and production rights, the authorities contracted TGS-NOPEC to conduct a seismic and gravimetric study of the deep offshore areas, which only then became available to exploration thanks to technological advances. The tender was organised in 2002, leading...
to the award, in 2005, of one concession covering two deep offshore blocks. Later, new rights were awarded following direct negotiations with several companies that approached the authorities.

Regarding onshore, since 2001, ‘strong indications’ of gas in two wells in the Alcobaça region have been registered. Oil shows have also been registered, although production tests were inconclusive. In 2019, Australis Oil & Gas Portugal, Lda, current onshore operator of the Batalha and Pombal blocks, expects to obtain all necessary approvals in order to carry out a vertical pilot survey with a subsequent horizontal deviation, in order to test the occurrences of natural gas.

From 31 August 2015, exploration activities were pursued under concession agreements in nine deep offshore areas and one onshore area, which was the same as in the previous year. Direct negotiations were held regarding five onshore and four deep offshore concession areas. As a result, concession rights were granted covering deep offshore areas off the southern coast and onshore areas in the centre of the country. However, in 2017 and 2018, the government revoked most of the concessions covering onshore and offshore areas in on procedural grounds and partly motivated by environmental pressures. Presently, Australis Oil & Gas Portugal, Lda, is the only operator with two active concessions in Portugal.

Overall, the authorities’ attitude has been passive, responding solely to the initiative of interested companies rather that embarking on promotion, and reluctant to raise local unrest due to the population’s environmental concerns on exploration projects. This, coupled with the wrong perception that the country presents a high exploration risk, has resulted in an extremely low level of activity over the past few years. Nevertheless, a task force has been appointed to prepare guidelines and recommended practices regarding shale oil and shale gas exploration (fracking), which seems to indicate that some interest has been shown in assessing the potential of the country’s unconventional reserves.

The applicable tax system is relatively simple. A royalty is levied on production in excess of 10,000 barrels of crude oil per year, set at 9 per cent in the case of onshore areas and 10 per cent in the case of shallow offshore areas (water less than 200 metres deep). Deep offshore and natural gas production, as well as annual onshore production below 6,000 barrels of crude oil and annual offshore production below 10,000 barrels of crude oil are not subject to royalties. Oil companies are also subject to corporate income tax (plus a municipal and state surcharge), which is levied on their profits. Imports and exports must comply with EU law.

Conflicting interests with other activities that are seen as having a greater short-term social and economic impact affected most of the exploration operations in Portugal: in at least one case, the formal start of prospecting activities, has been postponed several times, delayed mostly due to concerns raised in the press that tourism could be negatively affected by these oil exploration operations. This situation led to the resolution by the operators of three development and production contracts for the offshore concessions named Santola, Lavagante and Gamba, held by the ENI/GALP consortium. According to the President of

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3 For further details on these two onshore contracts, see www.dgeg.gov.pt/ ‘Contratos de Concessão para Prospeção, Pesquisa, Desenvolvimento e Produção de Petróleo (ativos)’.
the Portuguese Oil & Gas Company, ‘legal constraints that made it objectively impossible to carry out drilling work off the coast of Aljezur’, regretting the loss of opportunity for the country to find out, once again the true potential for oil resources.4

A fresh look at the country’s petroleum potential could be justified because of the combination of technological advances enabling exploration and production operations at ever greater depths, the development of geological knowledge (and further discoveries made in the Grand Banks area) and a flexible and overall favourable legal and tax regime. At this moment, we believe there is no political interest in developing Portugal’s potential in this area. The Minister of Environment has already made it clear that his priority is to combat climate change and reduce dependence on fossil fuels, ambitions difficult to reconcile with further oil and gas prospection.

Under Decree-Law No. 165/2013 of 16 December, as amended on 29 August 2014 by Decree-Law No. 130/2014, the former EGREP (Managing Authority of Petroleum Products Strategic Reserves) changed its name to the National Authority for the Fuel Market (ENMC), and more recently to the ENSE (National Entity for the Energy Sector) keeping its specific role as the entity responsible for constituting and maintaining the strategic portion of the national emergency stocks of crude oil and petroleum products.

As mentioned above, the DGEG’s responsibilities with regard to exploration, development and exploitation of oil resources were also transferred to the ENMC. In spite of this, there is a duty of cooperation and articulation with the DGEG regarding the preparation of laws and regulations, and on drafting relevant statistical information.

However, the legislative tendency of transferring responsibilities to the ENMC has been reversed by State Budget Law of 2017 that determined the future extinction of the Energy Services Regulatory Agency (ERSE). This trend has been developed by recent legislative and governmental measures proceeding to the restructuring of the administrative agencies in charge of the energy areas.

The first of the above-mentioned measures is Decree-Law No. 57-A/2018, of 13 July (already in force), which amends the by-laws of the ERSE, an important regulator empowered with regulatory powers in the electricity and natural gas areas). This amendment broadens the ERSE’s powers, which now encompass the LPG, oil derivatives and biofuels sectors, which were transferred from the ENMC. Under the Decree-Law and as part of the competent bodies of ERSE, the Council for Fuels is created in order to serve as a consulting body for the execution of ERSE’s powers in the LPG, oil derivatives and biofuels sectors.

The second measure relates to the approval, by the Portuguese Counsel of Ministers dated 26 July 2018, of the restructuring of the ENMC, the DGEG and the Energy and Geology National Laboratory. The above-mentioned Act has not yet been published, but according to an official governmental press release, it will encompass a redenomination of the ENMC, which will now be named the ENSE. According to the press release, this institutional restructuring aims to aggregate the supervision powers over the whole the energy sector in the ENSE. Also, it will transfer back to the DGEG the ENMC’s powers concerning the development, prospection and production of oil resources and licensing in the fuel and LPG sectors.

II  LEGAL AND REGULATORY FRAMEWORK

i  Domestic oil and gas legislation

The Oil and gas system is governed by Decree-Law 31/2006, of 15 February, which sets the General Framework for the Organization and Functioning of the National Oil System, as amended by Decree-Law 244/2015, of 19 October that specifically governs refining, storage, transport and distribution, and more recently amended by Decree-Law 5/2018, of 2 February, and Decree Law 69/2018, of 27 of August, updating the general principles relating to the organisation and operation of the National Petroleum System, storage activities, transport, distribution, refining and marketing of oil product activities, and setting the organisation of crude oil and oil derivatives products markets.

These activities are not subject to prior licensing, save regarding environmental licensing when applicable, industrial facilities licencing when applicable and transport facilities licensing that takes into account the technical capacity of the performer. The public interest oil facilities are ruled out by Regulation No. 1094/2016, of 14 October that established some obligations and rules for performer, namely regarding the capacity management. Import and export is not subject to licensing, but selling is subject to a licence. There is a specific regime for jet fuel, LPG and oil derivatives licensing. The main principles of the oil market are freedom of access to activities, non-discrimination, equality of opportunities and freedom to choose the oil selling company.

Exploration and production activities are specifically regulated by Decree-Law No. 109/94, published on 26 April 1994 (the Decree-Law), which was recently amended by Law No. 82/2017 of 18 August. The following documents were published to complement its provisions:

a  Notice dated 21 July 1994, identifying the areas where oil exploration, development and production operations are permitted, amended by the notice dated 12 March 2002.

b  Dispatch No. 82/94, establishing the fees chargeable by the competent authorities for the issuance of preliminary evaluation licences and for the signature of concession agreements and assignment agreements.

c  Joint Dispatch No. A-87/94-XII, establishing surface rental charges.

d  Ministerial Order No. 79/94, published on 26 July 1994, establishing the basis of the concession agreements referred to in Article 83 of the Decree-Law.

These legal documents aim to clarify and simplify the rules and procedures governing oil and gas exploration and production, including the award of rights, and thus attract new investment to these activities.

The relevant contents of some major provisions of these legal documents are summarised below.5

Property of mineral resources

Any underground mineral resources in the areas subject to the sovereignty or dominance of Portugal are an integral part of the state’s public domain. Oil and gas exploration and production activities can only be performed under concessions granting exclusive rights without prejudice to any third parties, to other activities or resources, or to national interests in national defence, the environment, navigation and scientific investigation, and management

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5 For further details, see Section III.
and preservation of maritime resources. Conflicts must be resolved jointly by the overseeing ministers according to national interests and in compliance with applicable international law rules and principles. Studies merely aimed at providing better technical support to any requests for concessions can be conducted with a preliminary evaluation licence.

Recent Law No. 82/2017 of 18 August,6 which entered immediately into force, establishes that any administrative procedure relating to prospection, research, experimental exploration and exploitation of hydrocarbons shall be preceded by compulsory consultation with the municipalities, in the respective areas of territorial jurisdiction. If the administrative procedure relates to exploration in the National Exclusive Economic Zone (offshore), the consultation shall be addressed to the municipalities of the relevant coastal line.

The municipalities shall issue their opinion on the conditions for prospection and research activities, experimental exploration and exploitation of hydrocarbons, to provide the consulting entity with all the information available on the area required.

**Public tender procedure for award of concessions**

In line with EU directives on public contracting and to increase transparency in award procedures, the preferred method for the award of oil and gas exploration and production rights is a public tender organised by the DGEG through its Unit for Research and Exploration of Oil Resources, which publishes the announcements in the Official Gazette and in the Official Journal of the European Union, specifying the terms of reference of the tender and the basis of the concession agreements.

The DGEG assesses the bids, which must conform to the terms and conditions published with the announcement, and then submits a recommendation to the overseeing minister. The minister may decide to award the concession, depending on whether the received bids are satisfactory and comply with the terms of reference. The minister's decision is appealable to the administrative courts under general legal terms.

**Direct negotiations**

Any company interested in a concession must apply directly to the DGEG. If no public bidding is announced, the DGEG will negotiate the terms and conditions of the concession, which must conform to the applicable legal provisions, and, within 90 days (extendable for a further 60 days), submit a proposal to the minister.

**Preliminary evaluation licence**

A preliminary evaluation licence is limited to the analysis of existing data and documents, surface and wellbore samples, and other studies that contribute to a better understanding of the area’s petroleum potential. The licence lasts for a single non-extendable period of six months unless it is compulsorily terminated by the state if the licensee fails to comply with its obligations.

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6 First amendment to Decree-Law No. 109/94, of April 26, which establishes the legal regime for oil exploration, exploration and production activities.
Standards in petroleum activities

Within the limits of the law and the concession agreement, the concessionaire is free to decide on the best way to carry out its activities. However, it must perform the petroleum activities in a regular, continuous way and follow the best practices of the international petroleum industry, as it will be liable for losses and damages caused to the state or any third parties as a result of these activities.

Termination and revocation

The rights granted will terminate at:

- a) the end of the initial period if the concessionaire has not demarcated an oilfield, or at the end of the production period;
- b) the concessionaire’s request, effective on the whole or part of the concession area, with 30 days’ advance notice before the end of the third year or of any subsequent year of the initial period, or with one year’s advance notice at any time during the production period;
- c) any time, by mutual agreement of the state and the concessionaire;
- d) any time, by unilateral decision of the state as a penalty, if the concessionaire fails to complete any operations included in approved work plans and budgets, assigns any full or partial rights or without due authorisation, abandons an oilfield without due authorisation, or breaches any of its contractual obligations; or
- e) any moment at the state’s initiative, for reasons related to the public interest and with payment of fair compensation.

On terminating the concession, any works, information, equipment, instruments, facilities and other assets permanently linked to the concession will revert to the state, free of any charge, cost or compensation to the concessionaire.

Confidentiality

The concessionaire and its contractors must keep confidential all data and information pertaining to the concession for the duration of the concession, and must not disclose any such information without the DGEG’s prior authorisation.


ii Regulation

The DGEG7 has direct regulatory competence over oil and gas exploration and production activities, and develops its activities under the supervision of the overseeing minister. Therefore, interested entities should address the DGEG to resolve any issues concerning a concession agreement or a preliminary evaluation licence.

The DGEG acts as a facilitator in relations with other administrative entities, which may have interfering powers regarding the performance of operations, such as the environmental authorities. Fieldwork requires a formal environmental impact assessment and the adoption of adequate safeguards. Usual EU standards in these matters apply.

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7 www.dgeg.gov.pt/.
Works relating to onshore operations, namely seismic assessments, drilling and construction require prior licensing from the competent municipal licensing entities. The maritime authorities grant licences for offshore operations and construction activities in areas subject to their jurisdiction (such as shoreline and harbours).

Support and ancillary activities, usually carried out by contractors (such as land, air or sea transport, construction and radiotelegraphy) may require specific licensing as per general rules and regulations. This licensing requirement may also apply to contractors, as it is the concessionaire’s responsibility to ensure that all its contractors have the required licences in good order.

### Treaties

Portugal is a signatory of the New York Convention, and has a long-established practice of agreeing to arbitration as the preferred method for settling disputes, even when the state is a party.

The Decree-Law states that a concession agreement (and its preliminary evaluation licence) has the nature of an administrative contract and that any disputes with the concessionaire arising from the concession agreement must be settled by arbitration, to be held in Portugal under Portuguese procedural laws.\(^8\) According to the Decree-Law, concession agreements must contain an arbitral clause.

Portugal has concluded bilateral investment protection treaties with 53 countries,\(^9\) and has signed treaties to avoid double taxation with 79 countries based on the OECD model.\(^10\)

### LICENSING

Concession agreements that comply with the Decree-Law are the means of granting oil and gas exploration and production rights. The key terms of concession agreements are described below:

- **a** Concession area: A single concession area may comprise up to 16 contiguous lots, arranged in one or more blocks.\(^11\)
- **b** Rights granted: The concessionaire has the exclusive right to explore and, in the event of a discovery, develop and produce the crude oil and natural gas discovered.
- **c** Initial period: The concession activities are split into several phases. The first phase is dedicated to exploration, defined as all office, laboratory work and fieldwork carried out in the concession area to discover or appraise petroleum accumulations not already

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8 In this case, the arbitral procedure would likely be ruled by the arbitral procedure regulation in Act 63/2011, published on 14 December.

9 Albania, Algeria, Angola, Argentina, Bosnia and Herzegovina, Brazil, Bulgaria, Cape Verde, Chile, China, Croatia, Cuba, Czech Republic, East Timor, Egypt, Gabon, Germany, Guinea-Bissau, Hungary, India, Jordan, Kuwait, Latvia, Libya, Lithuania, Macau, Mauritius, Mexico, Morocco, Mozambique, Pakistan, Paraguay, Peru, Philippines, Poland, Qatar, Republic of Congo, Romania, Russia, São Tomé and Príncipe, Senegal, Serbia, Slovakia, Slovenia, South Korea, Tunisia, Turkey, Ukraine, United Arab Emirates, Uruguay, Uzbekistan, Venezuela and Zimbabwe.

10 76 are already in force and three are signed, but still pending an exchange of notices to come into force. See http://info.portaldasfinancas.gov.pt/pt/informacao_fiscal/convencoes_evitar_dupla_tributacao/convencoes_tabelas_doclib/Documents/Table_DTC_2018.pdf .

11 For deep offshore areas, these limits may be exceeded.
included in a general development and production plan (see below). This phase lasts eight years\(^\text{12}\) extendable at the concessionaire’s request for two additional periods of one year each).

d Annual work programmes and budgets: During the initial period, the concessionaire must submit a detailed annual work programme to the DGEG before the end of October. This work programme must include a budget for activities to be carried out in the following year. The DGEG may reject a plan if it breaches the law or the concession agreement, and ask the concessionaire to submit a new plan. Whenever technically justified, the concessionaire may submit amendments to the annual plan to the DGEG.

e Performance of activities: Once an annual plan has been approved, the activities specified in it are, in principle, also considered approved. However, the concessionaire must not start field operations (including geological and geophysical surveys, exploration drilling and gathering of samples for study) without the DGEG’s approval. The concessionaire must request this approval with 30 days’ advance notice. The DGEG will ask the concessionaire to submit a new proposal if the original proposal breaches the law or the concession agreement.

f Contractors: The concessionaire can use contractors to perform any activities or operations. The concessionaire must give prior notice to the DGEG of any contracts it intends to enter into for these purposes, and inform of the scope, duration, identity of the contractor and of the persons in charge of supervising these operations and activities.

g Bonds: During the initial period, the concessionaire must annually post a bond (a first demand bank guarantee or similar) for an amount equal to 50 per cent of the budget submitted to the DGEG for the relevant year. This bond must guarantee the payment of penalties or compensation for the breach of obligations and for any damage caused while performing operations.

h Exploration wells commitment: Exploration activities include drilling a number of exploration wells, as scheduled in the concession agreement. In principle, from the fourth year of the concession, at least one exploration well must be drilled in each block each year. The number of wells drilled in excess of the annual commitment are considered included in the commitment relating to the subsequent year.

i Area relinquishment: At the end of the fifth concession year, the concessionaire must relinquish at least 50 per cent of the area not included within demarcated areas (see below).\(^\text{13}\) The concessionaire can choose which parts of the concession area to relinquish. The relinquished area must have a regular polygonal shape.

j Discovery, delineation and production: If, before the end of the initial period, the concessionaire identifies an oilfield within the concession area, it must provisionally demarcate the relevant area (which must have a regular polygonal shape) and submit to the DGEG a general development and production plan of the oilfield. The plan must include a technical report describing the reservoir, a delineation map, and a development and production work programme, along with maps showing the location of facilities to be built. It must also describe prospective investments and the financial means to support them, specify the estimated production start date and a schedule of production over time, and provide a list of licences and permits obtained or pending. Once this plan is approved, a 25-year ‘production period’ will start in respect of the

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12 For deep offshore areas, the duration limit may be exceeded.
13 For deep offshore areas, the area to be relinquished may be smaller.
Portugal

delineated area, and the concessionaire must subsequently submit a detailed annual plan and budget regarding the following year’s activities in the area. The concessionaire must submit the final delineation within five years. However, the DGEG may extend this deadline if it is technically justified. The production period may be extended for one or more periods of at least three years, up to 15 years.14

k Rights to oil and gas: The concessionaire is entitled to extract and freely dispose of oil and gas resulting from its production operations. Flaring of any associated gas not used in production operations or channelled to commercial use requires the overseeing minister’s approval.

l Transportation and storage facilities: The concessionaire can build transportation and storage facilities as required. Any surplus capacity in these facilities may have to be made available to third parties in mutually agreeable terms and conditions.

m Health and safety: The concessionaire must fulfil all national and EU health and safety regulations, and prepare and submit to the DGEG the plans and measures necessary to ensure fulfilment, keeping them permanently updated.

n Environmental protection: The concessionaire must adopt all necessary measures and precautions to minimise the environmental impact of its activities, and must submit to the DGEG its environmental protection plans in a timely manner as per applicable legal provisions.

o Unitisation: Oilfields extending beyond the concession’s boundaries will be unitised if the area to which the oilfield extends is included in another concession. If the area is free, the concessionaire is entitled to request direct negotiations for the rights over that area. If the concessionaires of two adjoining areas disagree on the terms and conditions of the unitisation, the government may integrate the oilfield into one of the concessions under reference, basing its decision on sound economic and technical criteria. In this case, the government could also terminate the affected concessions, paying the appropriate compensation to the concessionaires whose interests are affected.

p Plugging and abandonment: The plugging of wells and abandonment of an oilfield on the grounds of lack of economic profitability or technical feasibility is subject to the DGEG’s approval.

The preliminary evaluation licence is a much simpler document. The rights enable the licensee, for a limited period, to access information with the purpose of conducting studies that may help substantiate its interest in securing concession rights.

IV PRODUCTION RESTRICTIONS

The concessionaire can market, domestically and abroad, the oil and gas it produces. Only restrictions contained in international sanctions to which Portugal is bound apply.

There is no specific requirement to satisfy national oil and gas needs. In the event of war or national emergency declared by the government, all or part of the production may be requisitioned to ensure that Portugal’s strategic requirements are met. The concessionaire is entitled to compensation in an amount equal to the market value price of the quantity of the requisitioned product.

14 For deep offshore areas, the time limits may be exceeded for the production period and its extensions, and for submitting the final delineation of the oilfield.
Market price, for these purposes, and for determining taxes, is defined as the price currently prevailing in international markets for products with similar characteristics.

V ASSIGNMENTS OF INTERESTS

Subject to prior approval from the supervising minister, requested through the DGEG, the concessionaire (or licensee) can assign all or part of its rights to third parties. The sale of 50 per cent or more of the concessionaire’s or licensee’s shares will be deemed an assignment.

The request must fully identify the assignee and provide adequate information on its technical and financial capabilities. The decision is made under ordinary administrative procedures and is usually issued within 90 days. A fee is payable on occasion (see Dispatch No. 82/94).

The assignment may be subject to competition sanctioning according to applicable legal provisions.

If the assignment is made by selling a participating interest, the gain (difference between book value and actual selling price) resulting from the proceeds of the sale will be subject to tax.

VI TAX

The concessionaire will pay surface rental charges as stated in the concession agreement, which vary from €12.50 to €250 per year per square kilometre\(^{15}\) according to the potential of the area and the contractual period.

There is a royalty on the value of the annual production. The applicable sliding scale rates are determined according to the table\(^{16}\) below.

<table>
<thead>
<tr>
<th>Crude oil</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>Onshore fields</td>
<td>0–9</td>
</tr>
<tr>
<td>• Annual production up to 300,000 tonnes (± 6,000 bbl/d)</td>
<td>0</td>
</tr>
<tr>
<td>• Annual production between 300,000 and 500,000 tonnes (± 6,000 – 10,000 bbl/d)</td>
<td>6</td>
</tr>
<tr>
<td>• Annual production in excess of 500,000 tonnes (± 10,000 bbl/d)</td>
<td>9</td>
</tr>
<tr>
<td>Shallow offshore fields (&lt; 200 metres water depth)</td>
<td>0–10</td>
</tr>
<tr>
<td>• Annual production up to 500,000 tonnes (± 10,000 bbl/d)</td>
<td>0</td>
</tr>
<tr>
<td>• Annual production in excess of 500,000 tonnes (± 10,000 bbl/d)</td>
<td>10</td>
</tr>
<tr>
<td>Deep offshore fields (&gt; 200 metres water depth)</td>
<td>0</td>
</tr>
<tr>
<td>Natural gas and condensates</td>
<td>0</td>
</tr>
</tbody>
</table>

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\(^{15}\) These amounts were set in 1995 in the Joint Dispatch mentioned above.

\(^{16}\) See Article 51 of Decree-Law No. 109/94, dated 26 April.

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The concessionaire is subject to corporate income tax at the applicable rates, which is levied on its profits.\textsuperscript{17} The following tax rules shall also be considered:

\begin{itemize}
\item \textit{a} investments made in crude oil and gas exploration should be accounted for as intangible assets (exception made to the ones whose useful life period exceeds the exploration phase);
\item \textit{b} investments referred to in item (a) above may be amortised pursuant to general applicable corporate income tax rules as of the commencement of production. However, investments allocated to a discovery and its subsequent appraisal during the exploration phase may be fully deductible in the first full year of production;
\item \textit{c} the concessionaire may constitute or reinforce tax-deductible provisions to finance its oil and gas investment in exploration activities in Portugal in the three years following that constitution or reinforcement. The amounts provisioned cannot exceed the lower of the following:
\begin{itemize}
\item 30 per cent of the value of gross sales of crude oil produced in the concession areas in the year when the provision is made or reinforced; or
\item 45 per cent of the amount of the taxable income that would be calculated before determining the amount to be allocated to the provision.\textsuperscript{18}
\end{itemize}
\end{itemize}

If these requirements are not met, the net profits of the tax period in which this non-compliance occurs must be adjusted accordingly. This deduction is conditional on the non-distribution of profits equal to the amount remaining uninvested.

\section*{VII \textsc{Environmental Impact and Decommissioning}}

According to Decree-Law No. 151-B/2013, of 31 October (as amended by Decree-Law No. 47/2014, of 24 March, and Decree-Law No. 179/2015, of 27 August, Law No. 37/2017 of 2 June and Decree-Law No. 152-B/2017, of December 11), an environmental impact assessment must be submitted to and approved by the Portuguese Environmental Agency before launching any projects that are likely to significantly affect the environment, including oil and gas operations. Thus, the environmental impact assessment is considered a preventive method to foresee, estimate and reduce negative impacts and introduce possible alternatives, based on studies and data. The outcome of the assessment is an environmental impact statement. The statement includes the decision, which may be favourable (with or without conditions) or unfavourable.

Law No. 37/2017 of 2 June, which entered into force on 3 June and amended Decree-Law No. 151-B/2013, makes the environmental impact assessment mandatory in

\textsuperscript{17} Rates may vary annually in accordance with the provisions of the state budget approved by parliament. Corporate income tax rate is currently 21 per cent. An additional municipal surcharge applies (up to 1.5 per cent, as defined by each municipality), being a state surcharge applicable as follows:

\begin{itemize}
\item \textit{a} taxable profits in excess of €1.5 million = 3 per cent;
\item \textit{b} taxable profits in excess of €7.5 million = 5 per cent; and
\item \textit{c} taxable profits in excess of €35 million = 9 per cent.
\end{itemize}

\textsuperscript{18} See Article 42 of the Portuguese Corporate Income Tax Code and Article 50 of Decree-Law No. 109/94, dated 26 April.
the prospection, research and extraction operations of hydrocarbons. Previously, only the
extraction of hydrocarbons equal to or greater than 300 tonnes per day was subject to the
environmental impact assessment procedure.

In addition, Law No. 37/2017 establishes a technical committee with the aim
of monitoring the execution of prospection, research and extraction of hydrocarbons,
guaranteeing the exchange of information between the relevant entities, monitoring
enforcement of prospection, research and production of oil, and issuing recommendations.

Article 5 of Law No. 37/2017, which applies to concession agreements already entered
into force or licences already issued, establishes that there cannot be an administrative
permission for the subsequent phases under Decree-Law No. 109/94, without complying
with Law No. 37/2017. This means that an environmental impact assessment may be
required.

The Decree-Law does not have any specific decommissioning rules. However, the
concessionaire’s general duty is to act in accordance with the best practices of the industry (see
Section II.i), and general legal provisions and principles governing environmental protection
and safety would apply subsidiarily to abandonment.

The concessionaire can abandon an oilfield for technical or economic reasons provided
that it requests the minister’s permission through the DGEG, which will convey the request
to the minister, with its recommendation, within 30 days of receipt of the concessionaire’s
request. If the minister’s decision is not communicated within 90 days of the DGEG’s receipt
of the concessionaire’s request, the concessionaire may deem that the decision was negative
and submit the issue to arbitration.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The favoured way to award concession rights is through public bidding. However, the last
public tender was organised in 2002 and there are no plans for a new one in the foreseeable
future. Therefore, the advisable route for interested companies would be to approach the
DGEG to conduct direct negotiations.

The concessionaire does not have to be a Portuguese company, nor does the law require
it to incorporate a local subsidiary. However, a form of local establishment must be created.
Opening a branch of a foreign corporate entity satisfies this requirement.

The purpose and main advantage of incorporating a branch (which is not a separate
legal entity, but rather an extension of the head office with recognised local standing) is
related to the simplification of foreign companies’ activities and the reduction of direct and
indirect costs. The branch, as part of the foreign company, is not required to have its own
share capital. The incorporation documents may allocate to the branch a certain amount that
will be used as equity to fund its activities.

The branch managers designated by the company will be given all the powers necessary
for the appropriate management of the branch.

Formalities for incorporating a branch:

1. a resolution is adopted by the appropriate body of the foreign company authorising the
creation of the branch in Portugal, stating the amount of the equity eventually allocated
to it and the address of its office, and identifying the managers;

2. a power of attorney is executed by the legal representatives of the foreign company
granting powers to the branch managers;
c a certificate of corporate denomination for the branch is obtained from the National Register of Corporate Entities (RNPC);

d the branch is registered with the commercial registry office;

e the start-up is notified to the tax authorities; and

f the branch is registered with social security.

Incorporating a local company is more complex, takes longer and involves the following formalities:

a a certificate of corporate denomination or legal entity name is obtained from the RNPC;

b taxpayer identification numbers for foreign shareholders and future foreign managers or directors are obtained;

c a bank account is opened and the minimum compulsory amount of the share capital is deposited (minimum share capital is €50,000, of which 30 per cent must be deposited before incorporation, the remaining amount being deferrable for up to five years);19

d the incorporation agreement and articles of association (having certified the powers of attorney of the representatives and their signatures) are executed by the foreign company’s designated representatives;

e the company is registered with the commercial registry office;

f the incorporating documents are published online;

g the start-up is notified to the tax authorities;

h the company and its corporate body members are registered with social security; and

i the minute books of the general meeting and board of directors are opened.

A special fast-track procedure may be possible for the immediate incorporation of local companies and branches of foreign entities in Portugal. In this case, some formalities are shortened, as the investor is allowed to choose a corporate name from a list of pre-approved possibilities, and also from a set of by-law models, where the investor is required to fill in certain blanks, namely the amount of the share capital or equity, the description of the corporate purpose and the number of members of the corporate bodies and their identification. The investor may later make other changes to the models to suit its own purposes.

ii Capital, labour and content restrictions

Movement of capital and access to foreign exchange

Portugal is a Member State of the EU and part of the eurozone, and, therefore, applies EU internal market rules to capital movements and access to foreign exchange.

Without prejudice to the applicability of the harmonised legal framework on money laundering and terrorist financing, Portuguese law does not set limits for entry of foreign capital or access to foreign exchange. Save for limitations resulting from international sanctions, investments are treated under a principle of non-discrimination on grounds of nationality.

19 In the case of a company by shares (sociedade anónima), equivalent to the French SA or the German AG. In the case of another type of company, the 'sociedade por quotas,' similar to the French Sàrl or the German GmbH, there is no minimum amount of share capital, which may be freely established by the shareholders, provided that each 'quota' has a minimum nominal amount of €1. Shareholders must deposit at least 50 per cent of the amount of each ‘quota’ before the incorporation of the company, the remainder being deferrable for up to five years.
There is no requirement for national partners, or specific obligations for foreign investors, or any restrictions on dividend repatriation. Most foreign and local companies are free to invest in any industry or business sector. However, in the case of activities subject to administrative control or licensing, particularly oil and gas operations, specific requirements may apply, such as the award of a concession.

**Hiring of foreign workers**

Portugal is a signatory to the Schengen Agreement governing circulation of persons. There are no restrictions on the ability of oil and gas operators to hire employees who are Portuguese nationals or citizens of other EU Member States.

To hire workers from third countries, they must be duly legalised in Portugal or any other EU Member State, and hold a residence permit or temporary visa for that purpose. Obtaining a residence visa allowing the holder to work in Portugal depends on the employment vacancies that cannot be filled by Portuguese nationals or by nationals of other EU or EEA Member States, or of third countries with which the European Union has concluded an agreement on the free movement of people, as well as nationals of third countries legally residing in Portugal.

**iii Anti-corruption**

In general, Portugal applies the same measures to prevent active and passive corruption as are applied in the other EU Member States, namely those prescribed in Directive 2003/568/JHA, issued on 22 July 2003 by the European Council, which calls on Member States to criminalise acts of active and passive corruption and to adopt the necessary measures to ensure the criminal liability of legal entities for such acts.

Under Portuguese criminal legal provisions, organisations can be held criminally liable for crimes of corruption when improper tangible or intangible advantages are promised or given by a person that occupies a management position or is acting with delegated authority. The Portuguese Penal Code provides that legal entities are exempt from criminal liability for acts of corruption committed within the organisation if the perpetrator acted against express orders or instructions from management.

**IX CURRENT DEVELOPMENTS**

In recent months, there has been a public debate about possible environmental consequences of oil and gas exploration operations, and members of the parliamentary coalition that supports the current government have expressed an intention to tighten environmental regulations concerning seismic and drilling operations. Following this debate, government sources indicated that a review of the current legislation could be in order, given that the current texts date from over 20 years ago and, therefore, do not reflect properly the technological advances of the industry and the environmental and other relevant concerns. If these intentions are confirmed, approval of new legislation is likely to take several months.

Thirteen of the 15 concession contracts for prospection, research and exploration of hydrocarbons in Portugal have been cancelled or revoked between 2017 and 2018, particularly motivated by environmental and political pressures. Some terminations have been challenged and are subject to arbitration procedures. Currently two concession contracts remain in force, (named Batalha and Pombal) operated by Australis Oil & Gas Portugal, Lda since 30 September 2015, on the Onshore Lusitanian Basin.
INTRODUCTION

Russia is a major global producer, supplier and consumer of oil and gas. Its oil and gas industry is well established and efficient, given the severe climate and vast territories and distances. In 2018, Russia was once again the world’s largest exporter of natural gas by pipeline and the second largest exporter of crude oil and oil products (following Saudi Arabia and the US). Its share of total global exports of LNG has increased drastically and became comparable with exporters of LNG such as Nigeria and the US. Its share in oil refinery throughput was the third-largest globally (following the US and China). At the end of 2018, Russia had the largest share in the world total proven reserves of natural gas. Since it needs to explore for and discover significant additional resources in order to maintain and grow current production levels, this has resulted in an increased focus on exploration in the Arctic, in East Siberia and in the Far East.

Russia’s economy continued to be heavily reliant on revenues derived from its oil and natural gas exports and taxes paid by major hydrocarbon companies. Significant attention is paid to the development of the oil and gas (and, generally, energy) industry. The US and EU sanctions since 2014 that are targeted specifically at the ability of Russian oil and gas companies to access external financing and certain technologies, do not appear to have had an impact on Russia’s ability to maintain growth in the resources basis and production levels.

Europe remains the main market for Russian hydrocarbons. However, the Energy Strategy to 2030 provides for the diversification of its export markets away from the core European market to prospective eastern markets and the sizeable growth of oil and gas production and energy infrastructure in the Arctic North, East Siberia and the Far East. Russia is gaining a sizeable portion of the Chinese market. In 2018, it began shipments of LNG via the Northern Sea Route. In the meantime, Russia’s pipeline gas exports to Europe have set new records both in 2017 and 2018. This is set to increase further as a result of the planned commissioning of Nord Stream 2 gas pipeline to Germany and the Turkish Stream pipeline.

In 2019, the LNG receiving terminal was commissioned in Kaliningrad to avoid any pipeline gas transit problems and to secure guaranteed supplies of gas to this Russian region. The oil and gas industry in Russia remains robust. Russia has been active in the efforts to bring oil production and consumption into balance via modest cuts in oil production.

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1 Natalya Morozova is a Vinson & Elkins retired partner.
3 ibid.
4 ibid.
II LEGAL AND REGULATORY FRAMEWORK

Much of the current legislation governing the use of natural resources in Russia emerged around 1995 and has been evolving over the years since then. All of the key laws in this area have undergone continuous revisions and amendments and remain in a state of development.

i Domestic oil and gas legislation

The legal framework of the oil and gas legislation in Russia revolves around the following laws:

a The Constitution of the Russian Federation. It sets forth the principal rules on ownership rights to natural resources.

b The Federal Law on Subsoil (the Subsoil Law). This is the core law governing a vast range of rules covering the geological study, allocation, development and protection of natural resources.

c The Federal Law on Gas Supply in the Russian Federation (the Gas Supply Law). This law primarily governs natural gas development, transportation and sales.

d The Federal Law on Natural Monopolies. This law in part governs transportation of oil and gas via trunk pipelines.

e The Federal Law on the Continental Shelf of the Russian Federation. This law contains specific rules on the development of natural resources on the continental shelf.

f The Federal Law on Production Sharing Agreements. This sets forth the regime for the development of natural resources via production sharing agreements.

g The Federal Law on Export of Gas.

The following federal laws are also relevant to the legal framework of the natural resources industry of Russia:


b The Federal Law on Environmental Protection.

c The Federal Law on Ecological Expertise.


e The Federal Law on Exclusive Economic Zone of the Russian Federation.


g The Federal Law on Protection of Atmospheric Air.

h The Federal Law on Internal Waters, Territorial Sea and Contiguous Zone.


j The Federal Law on Foreign Investments In Strategic Companies.


The federal government has also adopted a policy on the oil and gas sector, the main document setting forth that policy being the 2030 Energy Strategy. The main objectives determined are:

a creation of an innovative and efficient energy sector;

b adequate development of the energy sector to comply with the needs of the growing economy and Russia's economic interests in international markets; and

c the energy sector as a driving force of the socially oriented innovative development.
Regions (i.e., the constituent subjects of Russia) may adopt their own laws and other legal acts governing the use of natural resources. These legal acts, however, cannot be in conflict with federal legal acts.

ii Regulation

The Ministry of Natural Resources and Environment is the government body that is responsible for the preparation and subsequent implementation of government policies in the oil and gas sector, as well as the development and regulation of research, use, replacement and protection of natural resources, including subsoil.

The Ministry of Natural Resources and Environment’s main objective is the replacement of reserves, since new discoveries are falling as the large producing deposits are being depleted. The Ministry has prepared a programme for the replacement of natural reserves to stimulate geological exploration up until 2020.

The Federal Agency for Subsoil Use, an agency subordinate to the Ministry of Natural Resources and Environment, is the key regulator of oil and gas extraction. Its responsibilities include:

- issuing subsoil licences and supervising the holders’ compliance with the terms of these licences;
- making decisions on the termination or suspension of subsoil licences;
- organising geological exploration of the subsoil by the state;
- maintaining federal and territorial geological data on the subsoil;
- organising the conduct of tenders and auctions for the right to use subsoil;
- maintaining the state cadastre of deposits; and
- making decisions on the discovery of deposits by holders of geological research licences.

The Federal Service for Environmental, Technological and Nuclear Surveillance is the key regulator of technical issues in the development of natural resources. It issues:

- mining allotments determining the boundaries of deposits; and
- industrial safety certificates and operating licences, including for hazardous industrial activities relating to oil and gas operations.

The Federal Service for the Supervision of the Use of Natural Resources is a federal government body subordinate to the Ministry of Natural Resources and Environment whose main responsibility is to ensure rational, uninterrupted and environmentally safe use of subsoil. It monitors and takes enforcement action in connection with violations in the use of subsoil and illegal actions causing a negative effect on the environment.

The Ministry of Energy is the government body that prepares and subsequently implements government policies and develops regulation in the fuel and energy industry, including oil and gas development, refining sectors, trunk oil, oil products and gas pipelines, the development of hydrocarbons on the basis of production sharing agreements and the petrochemical industry. Although the Minister of Energy is often in the world news in relation to the efforts of Russia to stabilise the global oil market and balance oil prices, the powers of the ministry in relation to the oil and gas sector are limited mainly to controlling the fuel and energy balance of Russia and its regions, development of gas supply programmes and gasification plans.
iii  Treaties

Foreign arbitral awards are in principle recognised and enforceable in Russia under the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, to which Russia is a party. In general, foreign arbitral awards are more enforceable internationally than court judgments rendered outside Russia as foreign judgments, as a rule, are enforceable under bilateral treaties only.

Russia has implemented the Law on International Commercial Arbitration, which is based on the UNCITRAL Model Law and under which any disputes of a commercial nature that involve a foreign party or commercial disputes where at least one party is a Russian company with foreign investments may be referred to international commercial arbitration. An arbitration agreement is mandatory for referral of disputes to international commercial arbitration and it must be in writing. There are certain exceptions, including, for example; insolvency proceedings, disputes about registration, reorganisation or liquidation of companies, disputes between companies and their shareholders, and competition issues. It is important to remember that an arbitral award rendered by a tribunal in Russia may be set aside by the state arbitration court. Recognition and enforcement of foreign commercial arbitral awards is conducted through state (federal) arbitration courts.

To promote foreign investment, Russia has signed and ratified a number of bilateral investment treaties (BITs). Although Russia has signed the Energy Charter Treaty (ECT), which is aimed, in part, at protection of foreign investments and protection against key non-commercial risks, it has never ratified the ECT. Under Russian law, the ECT is subject to ratification and as a result, has never become effective for Russia. Diligent investors structure their holdings in Russia so that they might gain protection from such a BIT. Many such BITs give investors a direct right of action against the state and the right to bring claims in international arbitration outside Russia. Although tax planning objectives typically prevail, some investors will structure their deals to obtain access to the investment protection remedies available through a BIT. Such structuring should occur at the time the deal is discussed and should be coordinated with tax planning.

Russia has entered into more than 80 bilateral treaties for the avoidance of double taxation.

III  LICENSING

Russian law provides for both a licensing and a production sharing regime for the use of natural resources.

The licensing regime is the main regime in Russia. It is governed primarily by the Subsoil Law and the subsoil regulations adopted under it. In general, the licensing regime is based on the administrative relationships between the state (the owner of subsoil) and private legal entities and individual entrepreneurs (the users of subsoil). A subsoil licence is a special government consent, which certifies the right of its holder to use a deposit within the stated boundaries, according to the stated purpose, during the stated period and in compliance with determined terms. Many such terms are determined in a licence agreement, which is an auxiliary and constituent part of a subsoil licence. Breach of the terms of a licence or a licence agreement by the subsoil user may result in termination or suspension of the licence, and, consequently, of the right to use the subsoil deposit. Such termination or suspension may be challenged in court.
The production sharing regime is characterised as a civil law relationship between the state and a private investor. However, it has very limited application. The use of subsoil under a production sharing agreement is governed primarily by the production sharing agreement itself, which is entered into under the Law on Production Sharing Agreements, but is also certified by a licence issued under the Subsoil Law. Under this regime, the grant of rights to exploit deposits under a production sharing agreement can only be approved by the passing of a special federal law. No production sharing agreements have been signed since the Law was adopted. There are now only a few operational production sharing agreements in Russia, all of which were signed before the end of 1995 when the Law on Production Sharing Agreements was adopted.

Under the Subsoil Law, a subsoil licence grants the licence holder an exclusive right to use a particular subsoil plot on the terms and conditions specified in the licence. These include terms specifying:

- the purpose of the subsoil use;
- the borders of the land plot granted for subsoil use;
- the deadlines (such as the start and end of the production);
- the production volume; and
- the payments for subsoil use.

These may be specified in more detail in a licence agreement entered into by a competent state authority and the licence holder.

There are several types of subsoil licences granted in relation to geological research and exploration, and the production of natural resources, including:

- a licence for the geological exploration and assessment of a subsoil plot;
- a licence for the production of natural resources; and
- a combined geological research, exploration and production licence allowing for geological exploration and assessment and subsequent production of natural resources.

Under the Constitution, natural resources in subsoil are state property and are subject to the joint jurisdiction of Russia and the region, namely the constituent subject of Russia, where the relevant natural resources are located. They are not owned by a holder of a subsoil licence until they are extracted. Russian law does not provide for any rights of an owner of the land surface to the subsoil under the land surface. Disposal of subsoil deposits is prohibited. Deposits cannot be the subject of any purchase, sale, gift, succession, contribution or pledge, or be disposed of in any other way.

Holders of subsoil licences have the right to perform geological research or extract natural resources. Such rights (certified by the applicable subsoil licence) can be transferred from one person to another if their transfer is permitted by federal laws. The Subsoil Law imposes very strict limitations on any transfers of the rights to use subsoil.

When extracted, natural resources become the property of the holder of the right to use subsoil and extract the relevant natural resources.
IV PRODUCTION RESTRICTIONS

A subsoil licence, a licence agreement or other documents enclosed with a subsoil licence usually impose certain obligations on a licence holder, including the obligation to reach and maintain certain agreed volumes of production. Production of resources above such volumes is prohibited. Production below such volumes or delay in reaching production levels are also considered breaches of the licence.

The right to use subsoil can be restricted, suspended or terminated in a number of cases and, in particular, if:

a. there is a direct threat to the life or health of people working or living in the area affected by the subsoil use;
b. the licence holder has breached material terms of the licence;
c. the licence holder systematically violates the subsoil use procedures;
d. an emergency occurs (natural disaster, military action, etc.);
e. the licence holder’s production does not reach the volumes required by the terms of the licence;
f. the licence holder has been liquidated;
g. the licence holder requests suspension or termination; or
h. the licence holder has failed to file reporting data in accordance with the subsoil laws.

The export of oil from Russia is restricted only by the capacity of the transportation system owned and operated by Transneft. Capacity in its trunk pipeline network and sea terminals is allocated to oil producers for export deliveries in accordance with the principle of equal access, based on information gathered by the Central Dispatching Department of the Fuel and Energy Complex.

As far as natural gas is concerned, Gazprom has a monopoly to export natural gas by pipeline. Historically, this monopoly also extended to the export of LNG, but recent developments, discussed further below, have resulted in a modest liberalisation of the regime as far as LNG is concerned. Inside Russia, Gazprom, as the owner of the United Gas Supply System (UGSS), must provide independent gas producers access to its natural gas transportation system, subject only to: availability of capacity on the UGSS; compliance of the gas being transported with established quality and technical parameters; and availability of connecting and branch pipelines to consumers. Reportedly, in some cases Gazprom abuses its rights.

Oil prices are not regulated. Natural gas prices and oil and natural gas transportation tariffs in Russia are regulated under the Law on Natural Monopolies and the Gas Supply Law. Wholesale price regulation applies to gas produced by Gazprom and its subsidiaries, but does not apply to gas produced by entities not affiliated with Gazprom.

The wholesale price of natural gas produced by independent gas producers is not regulated. However, certain consumers, such as residential consumers, are entitled to fixed retail gas prices. Historically, Gazprom has enjoyed the deficit of natural gas in the domestic market; however, at present, there is an overproduction of natural gas. The flexibility in terms of pricing available to independent gas producers who can offer discounts to customers has gradually helped them to gain, at Gazprom’s expense, a sizable share of the internal market.
V ASSIGNMENTS OF INTERESTS

In general, under Russian law, rights to use natural resources cannot be transferred by a holder to third parties through a direct transactional arrangement. As a result, the acquisition of shares (participation interests) in Russian companies that hold subsoil licences remains the primary mechanism of acquiring any existing interest in natural resources in Russia. Rights to use natural resources cannot be pledged or leased.

The Subsoil Law provides for a limited number of cases where subsoil use rights are, or can be, transferred from a subsoil user to another person or entity and the subsoil use licence is reissued in the name of the transferee without the need to undergo the procedure of applying for a new licence through a tender or auction. Such cases generally include corporate reorganisations, acquisitions of businesses in the course of bankruptcy proceedings, and transfers of subsoil use rights to related companies (from a parent to a subsidiary, from a subsidiary to a parent or between subsidiaries).

The acquisition of subsoil rights by foreign investors may be subject to certain restrictions and is discussed further below.

VI TAX

Generally, value from hydrocarbon resources is derived via taxation and export duties. The principal tax payable by extractors of natural resources in Russia is mineral extraction tax. It is generally calculated based on the value of natural resources extracted from the subsoil with reference to the price (excluding VAT and excise taxes) at which the extracted resources were sold, and is paid on a monthly basis. However, for oil, gas condensate and gas, mineral extraction tax is calculated based on the physical volumes of extracted resources.

In addition, producers of oil and gas are subject to corporate profits tax at the rate of 20 per cent. It applies to all taxpayers in Russia. Of the 20 per cent rate, 2 per cent is payable to the federal treasury and 18 per cent to the treasury of the relevant member region. Member regions (i.e., the constituent subjects of Russia) can grant a tax privilege of up to 2.5 per cent.

Producers of oil and gas are also subject to value added tax (VAT), which applies to the sales of goods, works and services in Russia or imported into Russia and is payable to the federal treasury. The main VAT rate is 18 per cent. Exports enjoy zero rate VAT and the right of recovery of input VAT.

In addition, Russian oil and oil products are subject to export customs duties. The Russian government establishes the rates of export customs duties for oil, oil products and liquefied petroleum gas (LPG) monthly. The rates are determined generally based on the methodology approved by the federal government, which generally accounts for the average world price of the Urals blend, Mediterranean and Rotterdam (for oil and its products), and the average prices for LPG at the border with Poland.

On 1 January 2015, Russia launched a reform in the taxation of the oil and gas upstream and downstream sectors. In general, the tax reform involves increasing the mineral extraction tax and decreasing the export customs duties and excises from oil products. In July 2018, the State Duma passed the laws governing completion of the tax reform (known as tax manoeuvre). According to the laws, export duties will be reduced from the current 30 per cent to zero per cent during six years beginning from 2019 with a simultaneous increase of mineral extraction tax on oil for three consecutive years up to 2021.
the tax reform includes reverse excises and dampening excises, as well as the right of the government to introduce export duties on exports of oil products. The foregoing measures were introduced to deal with the shortage of oil products on internal markets.

Reportedly, the tax burden of Russian oil companies amounts to about 30 per cent of their income. Rosneft and Gazprom are the largest and second-largest taxpayers.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Russian environmental legislation applies in full to oil and gas development. It establishes a pay-to-pollute regime administered generally by the Federal Service for Environmental, Technological and Nuclear Surveillance, which issues pollution discharge (harmful emissions) permits. Oil and gas production projects require both an environmental impact assessment by an independent environmental expert and a prior favourable environmental opinion issued by the competent public authorities. The purpose of this evaluation is to: (1) verify that the project ensures protection of the environment and the rational use and restoration of natural resources; and (2) assess the short-term and long-term environmental, economic and demographic impact of the subsoil use.

Further, subsoil licences are granted on the condition that the licence holder undertakes to comply with Russian environmental standards and norms (these include air, water and soil pollution limits, waste management requirements, animal protection, human health, and so on). Once a subsoil licence is issued, the licence holder’s compliance with licensing requirements is supervised by the Federal Agency for Subsoil Use (Rosnedra).

On expiration (or termination) of a licence, a licence holder must, at its own expense:

a ensure mining allotments and drilling wells are brought to a safe condition that is not hazardous to the life and health of the population and environment;

b recultivate the land and return it to a condition adequate for future use; and

c submit geological and other documentation.

Conservation must be conducted in a manner securing preservation of a deposit, mining allotment and drilling wells for the period of conservation.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

According to the Law on Foreign Investment in the Russian Federation (the Investment Law), foreign investors, including investors in the oil and gas sector, are allowed to make investments in Russia in any form that is not prohibited by law. Generally, foreign direct investment in Russia can be conducted either by forming (or purchasing an interest in) a Russian legal entity or by establishing a branch of a non-Russian company in Russia (without forming a separate legal entity). There are a variety of business structures that may be used by investors to form a subsidiary or create a joint venture with Russian partners.

According to the Civil Code of Russia (the Civil Code), commercial legal entities may be created in the form of, inter alia, business partnerships and corporations. The business forms that are typically used by foreign investors are joint-stock companies (public or non-public) and limited liability companies.
Formation of a joint-stock company or a limited liability company requires the adoption of a charter and the capitalisation of the company. The minimum charter capital of a limited liability company and of a non-public joint-stock company is 10,000 roubles and of a public joint-stock company 100,000 roubles.

A company must be registered with the state registration authority, which is the local tax inspectorate at the place of location of the company’s executive body. The registration of a company usually takes between five and 15 days. The newly created company is granted a main state registration number and a taxpayer’s identification number. The state registration is confirmed by a certificate of state registration issued by the tax inspectorate.

Simultaneously with the state registration, tax registration and registration with various funds (such as the Pension Fund) are conducted by the same authority. Following the state registration, shares in a joint-stock company must be registered by the Bank of Russia. The charter capital of a limited liability company is divided into participation interests, rather than stock.

Information on the state registration of a legal entity is incorporated in the Unified State Register of Legal Entities and is publicly available on the webpage of the Federal Tax Service on the internet at: www.nalog.ru.

According to the Civil Code, commercial companies can engage in any types of activities that are not prohibited by law. Some activities require obtaining of an operational licence (as discussed below) or participation in a self-regulatory organisation.

The predominant approach to structuring a business by foreign investors with Russian partners in Russia is still to use a non-Russian company formed in an offshore jurisdiction as a joint venture vehicle for the entire corporate structure. There are two primary reasons for this: (1) greater tax advantages and BIT protection; and (2) use of developed and predictable corporate governance rules to govern the relationship between the foreign investor and its Russian partners. Russian law allows corporate agreements between members or shareholders of Russian companies but the substantive law and, more importantly, Russian judicial practice, are still untested and controversial.

ii  Capital and labour restrictions

At present, the hard currency control regime is very liberal. There are no hard currency control requirements, such as government consent to loans or opening bank accounts outside Russia, or mandatory sales of hard currency proceeds. However, there are still a few requirements that are obligatory for Russian residents, including: (1) a general prohibition on payments in a foreign currency between Russian residents; (2) repatriation of hard currency export proceeds by Russian residents; and (3) registering of contracts with servicing banks in relation to import or loan transactions equal to or exceeding 3 million roubles or equivalent, and equal to or exceeding 6 million roubles in relation to export transactions. In addition, Russian residents are subject to rather burdensome reporting requirements.

Subject to a few exceptions set forth in international treaties, to work in Russia a foreign employee must have an individual work permit, and to employ foreign employees, a Russian employer generally must have the relevant permit or a patent. The validity of such permits or patents is generally limited to the region of Russia where they were issued. These permits must be applied for by an employer well in advance without any guarantee that they will be obtained. The term of the above permits are typically one year only and they are linked to a specific region. A significantly less burdensome and expedited regime of employment of foreign citizens, a 'highly qualified specialists regime' is available in all industries, including oil
and gas. At present, the main criteria that must be complied with in order to use such regime is to pay foreign employees no less than 167,000 roubles as a practical matter, each calendar month of the term of employment and to provide evidence quarterly of such payment to the Russian authorities.

iii Fields of federal significance

Some natural resources deposits (i.e., ‘fields of federal significance’) 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 or more of gas. Acquisitions of shares or indirect control over companies that hold subsoil licences to fields of federal significance are subject to significant restrictions pursuant to the Law on the Procedure of Foreign Investment in Business Entities Having Strategic Importance for the Defence of the Country and the Security of the State (the Law on Foreign Investments in Strategic Companies).

Foreign investment proposals are reviewed by the strategic investment government commission headed by the prime minister. The Commission’s prior approval is required for the acquisition of control over a target company involved in geological study or exploration and development of a field of federal significance. For these purposes, control is generally defined as the acquisition (directly or indirectly) of 25 per cent or more of the shares in the target company. If the acquirer is a foreign state or an international organisation (with certain exceptions) or a legal entity controlled by a foreign state or an international organisation, the threshold at which the prior approval of the Commission is required is reduced to 5 per cent. In addition, these acquirers are generally prohibited from acquiring control (25 per cent or more) over the above target companies. According to the most recent amendments in the Law on Foreign Investments in Strategic Companies, the above prohibitions now apply where the aggregate interest of one or several foreign states, or of separate companies controlled by one or several foreign states, exceeds the required thresholds (until recently, the law would look at the states’ or companies’ interests on a separate basis).

Other restrictions on the rights of foreign investors or Russian companies with foreign investments of any size to deposits of natural resources that are of federal significance are provided for in the Subsoil Law and the Law on the Continental Shelf and certain other laws. Russian law imposes the following restrictions that affect the ability of foreign companies and Russian companies with foreign investment of any size to acquire or keep control of significant natural resources deposits in Russia:

a the Russian government has the right to refuse to grant a production licence to, or to terminate a combined geological research, exploration and production licence held by, a foreign or Russian company with foreign investment, if it discovers a deposit that falls under criteria of a deposit of federal significance; and

b Russian national defence and security executive bodies are allowed to prohibit participation of Russian companies with foreign investment in auctions or tenders for the rights to use deposits of federal significance.

According to the most recent amendments to the Subsoil Law, however, restrictions to combined geological research, exploration and production on a deposit of federal significance apply to foreign investors and Russian companies controlled by foreign investors. Although not free from internal contradictions, the Subsoil Law appears to show a move towards
limiting restrictions to Russian companies controlled by foreign investors (and non-Russian companies), rather than imposing restrictions on Russian companies that have a level of foreign investment that is short of ‘control’.

Any transfers of existing licences for such deposits to companies with foreign investment that exceed the thresholds or do not otherwise comply with the criteria outlined in the Law on Foreign Investments in Strategic Companies with regard to natural resources in deposits of federal significance are prohibited. The only exemption to this prohibition is a transfer pursuant to a resolution of the government of Russia. The production of natural resources from a deposit of federal significance under a combined licence can commence only after the geological study stage is completed and a resolution of the government granting the right to production is taken.

Further, licence holders for deposits located or partially located on the Russian continental shelf must be Russian companies with no less than five years’ experience of working on the continental shelf and with more than 50 per cent of their voting shares directly or indirectly owned or otherwise controlled by Russia. This restriction effectively prohibits any foreign investment in the Russian continental shelf other than via the Russian state-controlled majors Gazprom and Rosneft. The prohibition specifically affects Russian Arctic oil and gas programmes. Non-Russian companies participating in these programmes do not have an interest in the deposits.

A transferee of a licence relating to a field of federal significance that is a Russian entity with foreign participation must submit evidence supporting that the transfer of the licence to the transferee is not prohibited under the Subsoil Law or, alternatively, the resolution of the government granting consent to the transfer. If the government resolution is not provided by the transferee, then the Federal Agency for Subsoil Use must forward the supporting evidence to the Federal Antimonopoly Service and it is entitled to reject the requested transfer of the licence.

If, in the course of a geological study, a subsoil user who is a foreign investor or a Russian legal entity with foreign equity investment makes a discovery of a field of federal significance, the government may refuse to grant the right to use the deposit for exploration and production or, if the licence is a combined licence, may terminate the right to use the deposit for exploration and production, on the grounds of a threat to national defence and security. In these circumstances, the licence holder’s expenses incurred in carrying out the survey and evaluation, as well as the lump sum payment made by a licence holder in accordance with the combined licence terms, must be compensated.

iv  Anti-corruption

It is an overall perception that corruption within government and, in particular, law enforcement bodies and the lack of an accountable, competent and reliable court system are the key problems that Russia faces in attempting to secure increased levels of foreign direct investment (as well as internal investment). Some businesses and individuals do not trust the government and law enforcers, and generally view them not as protective, but as dangerous factors. The oil and gas industry is arguably less affected by government corruption because of the dominance of state-controlled major companies.
v Export restrictions

Historically, Gazprom has had a legal monopoly to export natural gas in all its forms, including LNG. However, there had been a perception that if Russia does not adopt an active policy, it risks completely losing the global LNG market to competitors.

In November 2013, amendments to the Law on Export of Gas were adopted that allow the export of LNG, by subsoil users whose subsoil licence provides for the construction of an LNG plant as of 1 January 2013, in addition to Gazprom and its subsidiaries, and state-controlled companies whose deposits are located within territorial waters, internal seas, on the continental shelf or the Black and Azov Seas may also export LNG. The effect of this ‘liberalisation’ (and its obvious purpose) was to benefit Yamal LNG, its main shareholder NOVATEK and Rosneft, without restricting Gazprom’s monopoly to supply natural gas through pipelines to external markets.

IX CURRENT DEVELOPMENTS

On 12 August 2018, following more than 20 years of discussion, five Caspian coastal states, including Russia, signed the Convention on the Legal Status of Caspian Sea. The event was described as epoch-making. The Convention will serve as a basis for the delimitation of the seabed, which will still require further separate treaties between the littoral nations. The way to divide the huge oil and gas resources of the Caspian Sea is opening frozen and allowing new energy projects in the area.
Chapter 25

TRINIDAD AND TOBAGO

Jon Paul Mouttet, Lesley-Ann Marsang and Simonne Jaggernauth

I INTRODUCTION

Trinidad and Tobago (T&T) has a mature petroleum industry. The first oil well was drilled in 1857 in the vicinity of T&T’s Pitch Lake in La Brea. The first successful well was drilled in 1866 in Aripero, and commercial oil production is recorded as having begun in 1902 near the Pitch Lake. Until the mid-1950s, petroleum exploration was land-based. In 1954, exploration moved offshore into the East Coast marine areas resulting in significant discoveries. Marine exploration now extends into the deep.

Petroleum rights in T&T are owned by the state (public petroleum rights) or by private persons (private petroleum rights). Prior to 30 January 1902, the original grants of real estate by the state included all sub-surface rights not expressly reserved by the state. This effectively vested private persons with petroleum rights. Thereafter the state reserved all sub-surface rights. Public petroleum rights are vested in the state and exercisable by the President. They exist in state lands, private lands where the sub-surface rights have been reserved to the state and all marine areas. It is not uncommon for private petroleum rights owners to dispose of their surface rights and retain the subsurface petroleum rights.

T&T is the most industrialised nation in the Caribbean and is one of the wealthiest because of its oil and gas reserves. The exploitation of hydrocarbons dominates its economy. The availability of historically inexpensive natural gas as feedstock has facilitated a well-developed petrochemicals sector. T&T is one of the world’s largest exporters of ammonia with 11 ammonia plants, seven methanol plants with an eighth under construction, two urea plants, nitric acid, ammonium nitrate, urea ammonium nitrate, melamine plants and a dimethyl ether plant under construction. It is one of the largest exporters of liquefied natural gas in the world operating a four-train liquefaction facility. In late 2018, T&T’s last functioning oil refinery was shut down by the state-owned Petroleum Company of Trinidad and Tobago Limited (Petrotrin) following a government decision to restructure Petrotrin’s refining and exploration and production business.

Owing to a lapse in exploration activity (which resulted in a decline in reserves) and falling oil prices, the T&T economy has faced hardships in recent years. Gas shortages also affected the petrochemical sector. 2019 continues to show promise with global oil prices
demonstrating some signs of strengthening, additional natural gas discoveries, bettered supplies of natural gas to the downstream as well as confirmed commitments for investment by the upstream.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The petroleum industry is governed primarily by the Petroleum Act (the Act) and the Petroleum Regulations (the Regulations). Together they address the grant of exploration and production licences (E&P Licences) and production sharing contracts (PSCs) for upstream onshore or offshore exploration and production and several other petroleum operations.

The term ‘petroleum operations’ is widely defined under the Act, it includes petroleum exploration and production but excludes petroleum mining or extraction from shales, tar sands, asphalts or like deposits. The Act and the Regulations do not address specific gas-related issues; nor do they address unconventional petroleum exploration (such as fracking or shale gas). As a result, specific gas related issues are normally dealt with by more detailed provisions included in the relevant PSC or E&P Licence.

It is an offence under the Act for petroleum operations (whether relating to public or private petroleum rights) to be conducted without a licence. The fine for failing to obtain a licence is currently TT$500,000, and in the case of a continuing offence, TT$50,000 for every day in which the offence continues.

ii Regulation

The Minister of Energy and Energy Industries (the Minister) is the primary regulator of the petroleum industry and performs his or her functions through the Ministry of Energy and Energy Industries (MEEI). Petroleum operations also trigger other general regulatory requirements overseen by other regulators, for example, health, safety and environment (HSE) regulation.

The Minister, subject to the directions of the T&T Cabinet, is charged with the general administration of the Act (which together with the Regulations govern his powers and duties). He is responsible for, inter alia, regulating the petroleum industry, enforcing the provisions of the Act/Regulations, granting, revoking, varying and enforcing concessions and granting ancillary rights to concession holders.

iii Treaties

T&T is a member/signatory to several trade and investment treaties the most notable of which is the Caribbean Community (CARICOM). CARICOM’s main pillars are to promote economic integration, foreign policy coordination, human and social development and security within the Caribbean. CARICOM has entered into several Free Trade Agreements (FTAs) on behalf of its members with third states, following which T&T implemented these FTAs into its domestic legislation.

T&T has also entered into Bilateral Investment Treaties (BITs) with several countries designed to encourage favourable conditions for investors of those countries to make

4 https://caricom.org/about-caricom/who-we-are.
Investments in T&T.⁵ These BITs also require each party to grant investors of the other party terms no less favourable than those which it grants to investors of any third state in similar circumstances.

Many of these BITs are not incorporated into T&T’s domestic laws, and, therefore, T&T courts will not enforce them. BITs however typically specify dispute resolution mechanisms including international arbitration. Petroleum investments would normally be considered an ‘investment’ within a BIT, and if these investments were negatively affected by the government of Trinidad and Tobago, the aggrieved foreign investor may seek to enforce its rights (or have its country do so) under the relevant BIT through the specified dispute resolution procedure.

The Convention on the Recognition and Enforcement of Foreign Arbitral Awards, 1958 was incorporated into T&T’s domestic law by the Arbitration (Foreign Arbitral Awards) Act. The Convention relating to the International Centre for Settlement of Investment Disputes was also incorporated into T&T’s domestic law by the Investment Disputes Awards (Enforcement) Act. These statutes are designed to accelerate the enforcement process for arbitral awards in comparison to the slower procedure required at common law.

T&T has concluded several double taxation treaties that either reduce or completely mitigate the taxes imposed by the home treaty country on residents of the other treaty country.⁶

III LICENSING

Upstream concessions are granted by the state under: (1) PSCs; (2) public E&P Licences (which relate to public petroleum rights); (3) private E&P Licences (which relate to private petroleum rights); and (4) exploration licences. Where a concession relates to acreage that covers both public and private petroleum rights, the MEEI typically issues a single public E&P Licence. The concessions at (1) to (3) will include a minimum exploration work programme (MEWP), but its extent will vary between concessions. Rights in marine areas are now managed primarily by PSCs but a fair amount of marine acreage remains subject to public E&P Licences.

An E&P Licence confers the exclusive right to prospect for and dispose of petroleum in the licensed area. PSCs give similar exclusive rights in respect of a defined contract area. Neither confer ownership of any petroleum in strata. Exploration licences give a non-exclusive right to explore within the licensed area and are now seldomly issued.

Since the State does not own private petroleum rights, prior to any application to the Minister for a private E&P Licence the applicant must obtain the consent of the title holder (generally through an oil mining lease) and evidence thereof must be supplied to the Minister for verification.

Applications for E&P Licences must be made in writing to the Minister who then publishes them in the Gazette and at least one local daily newspaper to allow opportunity for public objection. An application fee of TT$500 is payable. If the application is in order, the Minister will decide the application after considering any objections.

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Public petroleum rights are exercisable by the President but the Minister is responsible for determining the areas to be made available for petroleum operations. The President in his or her discretion can, however, select an area to be subject to a competitive bidding process. The Minister must then publish a Competitive Bidding Order (CBO) in the Gazette and at least one local daily newspaper outlining, inter alia, the bid procedure, the available blocks and the bid assessment criteria.

Competitive bid rounds are standard for marine blocks. This process was also utilised in 2013 for certain onshore blocks. Successful bidders are selected by the Minister after analysis of the bids in accordance with the evaluation criteria (and the MEEI’s internal benchmarks) and in consultation with the Minister of Finance. PSCs have occasionally been awarded by the Minister out of round, where there were no acceptable bids and the MEEI requested a bidder (seemingly the bidder closest to the internal MEEI benchmark) to submit a revised bid.

Public E&P Licences are granted for the initial term of six years, and where a commercial discovery is made they can be renewed for a maximum term of 25 years, with further successive five-year extensions. Extensions of the initial term are possible in the absence of a commercial discovery where the Minister considers that continued exploration will enhance the identification or evaluation of reserves and the extension is in the public interest.

In addition to production royalties, E&P Licences tend to incorporate a combination of the following fiscal obligations including performance guarantees for the agreed MEWP, treasury deposit in cash, payment of all other applicable duties, taxes, charges or fees, annual surface rents, minimum payments for the licensed area, an escrow account for pollution remediation and abandonment of facilities and wells, annual training contributions for nationals, annual research and development payments, annual scholarships, signature bonus, technical equipment bonus, environmental bonus and production bonus. Relinquishment of portions of the licensed area is also required by the Regulations. Licensees are liable, without limitation for all damage caused as a result of their negligent actions or their subcontractors and are required to indemnify the Minister without limitation for resulting third-party claims brought against him or her.

Private E&P Licences are granted for a term of 20 years and subject to renewals for successive periods of 20 years. Private Licensees are not required under the Regulations to provide bonds or guarantees. The Minister, however, has included these obligations in private E&P Licences in the past. Production royalties are not payable to the Minister since the petroleum rights are privately owned. Private E&P Licences, in comparison to the public E&P Licences, tend to contain less onerous fiscal terms. The obligations normally include the payment of all applicable taxes, duties, charges and rents, a bond or guarantee for the abandonment of wells, escrow account for pollution remediation and abandonment of wells, annual contributions for training of nationals and additional monetary deposits. Otherwise, they are roughly similar to public E&P Licences.

PSCs have an initial exploration term and successive extensions similar to public E&P Licences. However the initial term is usually divided into shorter phases and proceeding from one phase into the other is dependent on satisfactory performance of the agreed MEWP for each phase. PSCs typically provide for specific guarantees with respect to the MEWP and work obligations undertaken in subsequent phases, a general third party or parent company guarantee for the breach of any obligation under the PSC, and a letter of undertaking from a financially, technically and legally competent parent company that it will provide the contractor with the technical and financial resources as are required to meet its obligations.
under the PSC. Specific relinquishment provisions are also provided for in each PSC. The exact percentage to be relinquished and the timelines for such relinquishment vary, and the Minister has the discretion to vary these requirements. Cash flows generated under PSCs come from the sale of petroleum by the contractor and are distributed between the Minister and the contractor in accordance with agreed cost recovery petroleum and profit petroleum splits, which are typically biddable. Cost recovery is not applicable to all revenues and defined accounting rules and procedures (with rights of audit) are specified in PSCs.

The majority of PSCs are ‘tax paid’ contracts where the Minister undertakes to pay the contractor’s taxes and other payments out of his or her share of profit petroleum and gives an indemnity from all other payments to and levies by the Treasury or the government (including royalties) whether or not existing at the date of the PSC, save for specified financial and tax obligations. Consequently, the tax regime applicable to upstream operations ought not to affect contractors directly. The tax obligations directly payable by the contractor typically relate to payroll taxes, stamp, import and excise duties and in some cases withholding tax. The Minister’s contractual undertaking or obligation to pay the contractor’s taxes is not fully supported by formal legislation and in those cases that undertaking or obligation to pay under the PSCs’ ‘tax paid’ provisions arguably does not strip the Revenue of its entitlement to pursue the contractor, though this has not, as far as we are aware, ever happened in practice.

Termination provisions in E&P Licences and PSCs can be triggered as a result of breach or pursuant to the normal expiry of the term or via voluntary relinquishment prior to its expiration. Items of material breach prompting a right of termination in E&P Licences and PSCs include failure to perform the MEWP and other work obligations and failure to obtain the prior consent of the Minister to an assignment. Termination on this basis usually first requires the giving of notice and the opportunity to remedy. E&P Licences may also provide for ministerial termination where the licensee fails to make any required payments, fails to pay any arbitral awards, becomes bankrupt or insolvent or makes a wilful misrepresentation in its E&P Licence application.

IV PRODUCTION RESTRICTIONS

Subject to any contrary requirements in the E&P Licence, a licensee has a general right to export petroleum. However, the President reserves the right under the Act to take possession of production and in times of emergency to require further production from the licensee. The Minister can also direct producing licensees to have their production refined locally though this is no longer practicable with the close of T&T’s last oil refinery in 2018. PSCs tend to address the issue of exportation in more detail, and the contractor’s right to export natural gas is more restricted. Marketing arrangements for any natural gas are subject to the Minister’s approval, and the contractor must demonstrate to the Minister that the price of the natural gas at the measurement point represents the fair market value obtainable. Any proposed export project for natural gas is subject to the discretion of the Minister. Apart from the restrictions on natural gas exportation, the contractor has a general right to export petroleum subject to the government’s right of requisition in times of war or national emergency with compensation.
ASSIGNMENTS OF INTERESTS

The Minister’s prior written consent must be obtained for any assignment or transfer of an interest under an E&P Licence and for the issue of a sublicense by a licensee. Failure to obtain consent renders an assignment or transfer null and void (at least against the Minister) and exposes the E&P Licence to forfeiture by the Minister. A written application for consent must be made to the Minister with a fee of TT$100, and provision of the same information in respect of the proposed assignee or transferee as required for an application for the E&P Licence. This restriction is not, however, sufficiently wide to prohibit transfers by virtue of changes in control.

Historically PSCs tended only to restrict the actual assignment of the PSC or an interest therein, and contractors under PSCs have often disposed of their interests by way of a sale of shares in the special purpose company used as the contractor entity to enter into the relevant PSC. In recent years, the MEEI has expanded the definition of the term ‘transfer’ under PSCs in an effort to ensure that disposals of the special purpose contractor entity by a sale of shares or a change in control will qualify as a transfer. We have not seen any E&P Licences incorporating similar language. Under modern PSCs, the Minister now reserves the right to impose a transfer fee upon the transfer of the PSC (or an interest therein) based on the value of the transfer consideration. This transfer fee will not apply if stamp duty has been paid on the transfer.

TAX

Apart from certain taxes applicable to all companies, petroleum companies involved in production operations are subject to the following separate taxation regime.

Petroleum Profits Tax (PPT) is payable at a rate of 50 per cent (35 per cent for deep water operations) and is the petroleum equivalent to corporation tax (which applies to other companies). Outgoings and expenses (other than capital allowances) are determined and deducted in accordance with normal income tax principles together with deductions for supplemental petroleum tax (SPT), petroleum impost (Impost), petroleum production levy (PPL) and royalty (each as explained below) in order to determine chargeable income.

SPT is charged on gross income from the disposal of crude oil. The only deduction permitted is royalty (including overriding royalty). SPT becomes payable when crude prices exceed specific thresholds on a sliding scale increasing with the price of crude and depending on the type of licence or PSC held.

Impost is to be paid by every E&P Licensee in respect of petroleum won and saved at rates per barrel of crude oil and per mscf natural gas as specified by the Minister. The applicable rates are published annually. The last rate published (for 2017) was 47.1533200 cents per barrel of crude and 8.1298828 cents per mcf of natural gas. The 2018 rates will be published in late 2019.

PPL is levied on every producer (the levy is pro-rated in accordance with a producer’s percentage of the country’s total production) in respect of any production business with a daily average production of over 3,500 barrels. The total levy is used to pay a subsidy to traders in the petroleum marketing business, which in turn supports a fuel subsidy for T&T consumers. The maximum charge that can be levied is 4 per cent of gross income from the production of crude oil. The subsidy is being gradually phased out.

Effective from 1 January 2018, royalties are payable by Public E&P Licensees and PSC contractors at a rate of 12.5 per cent on the net volume of crude oil and natural gas won.
and saved from the licensed or contract area at fair market value. However, arguably the existing tax paid or tax indemnified PSCs (which typically cover royalties) will prevail, and the Minister will continue to make these payments from his or her share of profit petroleum. However the terms of each PSC will need to be considered, and it is possible that any financial hardships experienced upstream will be passed down to the downstream industry.

Unemployment levy (UL) is payable at the rate of 5 per cent of taxable profits of a person for a current financial year. Unlike PPT, no relief is given for losses brought forward.

Though under general tax law, a contractor is liable for T&T tax, depending on the nature of the PSC, the Minister contracts to pay the contractor’s liability for PPT, SPT, UL, PPL, royalties, Impost and green fund levy (GFL). In addition there are various accelerated capital and other allowances and incentives available under the Petroleum Taxes Act and the Income Tax (In Aid of Industry) Act.

Taxes of general application include the following:

- GFL (0.3 per cent of gross income);
- VAT (at 12.5 per cent on imports and T&T based commercial supplies save where zero-rated or exempt);
- customs duties (at varying rates on imports according to the common external tariff);
- withholding tax on distributions and named species of payment to non-residents (at 5 per cent, 10 per cent and 15 per cent);
- PAYE, national insurance and health surcharge on emolument income paid to employees (the employer is responsible for deducting and remitting same to the Revenue);
- stamp duty (levied at varying specified statutory rates on various instruments); and
- property tax (this is a new tax and implementation is in process; it is payable on all land on an annual rental value basis (less deductions and allowances) at varying rates depending on whether the land is agricultural (1 per cent), residential (3 per cent), commercial (5 per cent) or industrial (6 per cent housed machinery and 3 per cent machinery not housed)).

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The Act and Regulations contain general provisions that are intended to protect the environment. The Regulations place obligations on Licensees to execute operations so as not to unreasonably interfere with other activities in the area and to take care to avoid pollution of marine areas. Licensees are also required to take all reasonable precautions and safety measures to ensure that water resources are not damaged or contaminated by operations. Where a Licensee fails to adopt appropriate measures for safety, health and welfare and for pollution prevention, the Minister may (upon the expiry of a default notice, where no emergency exists) execute such works and recover the costs and expenses from the Licensee. The MEEI also inspects and monitors environmental quality and equipment used in areas with energy related facilities. Recently the liability for proper facility abandonment and for pollution remediation has become a matter of increasing concern, particularly for marine areas. This has resulted in express provisions concerning environmental remediation being

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7 In terms of general marine related legislation, the Continental Shelf Act makes it an offence where oil escapes into the sea in a designated area from a pipeline or otherwise (other than from a ship) as a result of any operations for the exploration of the seabed and subsoil or the exploitation of their natural resources and the Oil Pollution of Territorial Waters Act makes it an offence for a vessel to discharge oil into T&T
incorporated into concessions. These usually involve the Contractor/Licensee making an environmental plan and setting up escrow accounts for the pollution remediation and the abandonment of facilities. The MEEI also normally requires Contractors/Licensees to undertake to comply with its National Oil Spill Contingency Plan. The Petroleum (Pollution Compensation) Regulations deal with onshore spills and a compensation process for redress where damage is caused to property, crops and other agricultural holdings.

The Environmental Management Act (the EM Act) together with its subsidiary legislation is the primary environmental law regulating upstream operations. The EM Act is focused on the implementation of laws and policies and a framework for the protection, conservation, use and management of the environment. It establishes the Environmental Management Authority (EMA), the principal environmental regulator with wide discretion over the kinds of action that it may take in the event of a spill of pollutants including petroleum. The Environmental Commission, a superior court of record sitting on appeals from EMA decisions is also established under the EM Act. The EM Act regulates the release of various pollutants and exploration, production, refining and decommissioning operations. The EM Act’s subsidiary legislation most pertinent to upstream operations include the Certificate of Environmental Clearance (CEC) Rules and the CEC (Designated Activities) Order under which CECs for various upstream activities (including exploration, production and decommissioning) are required before they can be started. The CEC process will also often require environmental impact assessments and a public consultation process. Other relevant rules include the Water Pollution Rules, Air Pollution Rules and Noise Pollution Rules, which address approvals, registrations and permits for operations causing these types of pollution.

The Occupational Safety and Health Act (the OSH Act) applies to all ‘industrial establishments’; this term includes vessels, offshore installations and any movable structure. The OSH Act is designed to revise and extend the law regarding the safety, health and welfare of persons at work and imposes duties and obligations on upstream operators to the extent that they employ persons working at industrial establishments. The Occupational Safety and Health Authority (OSHA) is charged with enforcing the OSH Act, and inspectors have the power to enter and inspect premises for the purposes of ensuring compliance. Apart from penalties for various offences, OSHA has the power to issue ‘prohibition notices’ that prohibit the use of premises until danger is removed and ‘improvement notices’ that require improvements to facilities in order to remove danger. Actions under the OSH Act are heard by the Industrial Court, which is a superior court of record established under the Industrial Relations Act. There are certain general duties owed by an employer to, among other things, ensure the safety, health and welfare at work of his employees, so far as is ‘reasonably practicable’. Other specific duties pertain to protocols where hazardous chemicals or substances are present and to the actions to be taken in the event of accidents and occupational diseases. Occupiers (those in ultimate control of a facility) also owe duties, many of which are owed to employees. These include the formulation of a general policy on health and safety and the preparation of various emergency plans, the appointment of a safety
practitioner and a duty to ensure that no unsafe structures exist. In addition, an occupier is responsible for managing the environment and protecting the public from dangers created by the operations of the industrial establishment.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Non-resident companies wishing to engage in upstream operations must establish a local place of business, branch or agency. Once a non-resident establishes a place of business in T&T it must formally register itself as an External Company within 14 days pursuant to the Companies Act by filing the appropriate Form 20 and supporting corporate instruments and declarations with the Registrar of Companies.

Non-resident companies can also incorporate either private limited or unlimited liability subsidiary companies. A name approval application must first be made which typically takes around five working days. Following receipt of the name approval, non-resident companies classified as ‘foreign investors’ under the Foreign Investment Act must prior to incorporation file an administrative notice with the Minister of Finance setting out specified particulars. Thereafter the relevant articles of incorporation, notices of directors, registered office and secretary are filed with the Registrar of Companies to effect the incorporation.

ii Capital, labour and content restrictions

There are no exchange controls on the negotiation of contracts, payment of obligations and holding of bank accounts in foreign currency. The Exchange and Control Act limits the purchase and sale of foreign currency to and by authorised dealers. There is no requirement for exchange control approval for foreign investments or the payments or repatriation of capital from T&T to a foreign country. However, T&T periodically experiences foreign currency shortages. The par value of the T&T dollar is floated against the US dollar and consequently against every other foreign currency.

Licensees are required under the Act to minimise employment of foreign personnel and train and seek employment of T&T nationals. The MEEI issued a Local Content & Local Participation Policy & Framework (the Local Content Policy) in 2004. It is very general. While it has not been passed into law, it is incorporated into PSCs and the more recent public E&P Licences.

PSC contractors undertake open-ended obligations to observe the Local Content Policy as modified from time to time together with specific obligations regarding local content including maximising the use of local goods and services, business, employment of T&T nationals, advertising, financing, evaluating and awarding all tenders in T&T (except where special permission from the Minister is obtained), imparting to nationals business and technology expertise in all areas of the energy sector and preparing and submitting periodic local content reports to the Minister.

Non-nationals may only engage in employment in T&T for a single period not exceeding 30 days every 12 months. Otherwise a work permit is obtained from the Ministry consideration for such shares must also be paid for in an internationally traded currency through a licensed dealer of foreign exchange.
of National Security. The application is considered by the Work Permit Committee which consists of various members of the Ministry of National Security, the Ministry of Labour and Small Enterprise Development and the MEEI (among others).

iii  Anti-corruption

T&T received a score of 41 out of 100 in Transparency International’s 2018 Corruption Perceptions Index and ranked 78th out of 180 countries. The Prevention of Corruption Act (the Prevention Act) is the main corruption legislation. The terms ‘bribe’ or ‘bribery’ are not defined, but a variety of actions are prohibited that would be regarded as offering or giving a bribe and seeking or receiving a bribe. Public and private sectors are subject to the Prevention Act, and it provides for offences involving the corrupt offering, promising, giving, soliciting and receiving of gifts, loans, fees, rewards and advantages. ‘Consideration’ is defined as including any valuable consideration of any kind, and so small grease payments are also prohibited. The use of an agent or third party (innocent or otherwise) in the commission of an offence will not allow the offender to escape criminal liability. Punishments for offences under the Prevention Act include fines, penalties, imprisonment and other forms of chastisement.

Other legislation with anti-corruption ramifications include: (1) the Proceeds of Crime Act which requires, inter alia, the disclosure of information on the source of certain funds and obtaining certain business information from clients or business partners in specified transactions; and (2) the Integrity in Public Life Act, which, inter alia, regulates the acceptance of gifts by those in public office and pubic life and mandates the periodic disclosure of financial information by those in public office and public life to the Integrity Commission.

While confirmed cases of corruption in the petroleum sector are rare, in 2017 there was some speculation surrounding certain fake oil transactions involving Petrotrin and an upstream operator alleging discrepancies between the operator’s actual oil production and delivery levels and purportedly inflated levels shown on invoices presented to and paid for by Petrotrin.

IX  CURRENT DEVELOPMENTS

T&T’s petrochemical industry has thrived over the years, but in prior years the industry faced some challenges due to gas supply shortages. These challenges appear to have been mitigated, at least in the short term, by the concerted efforts of the MEEI and the upstream operators. Recently, state-owned, The National Gas Company of Trinidad and Tobago Limited signed a term sheet with Shell Trinidad Limited for additional gas supplies.

In November 2018, the MEEI launched a shallow water bid round, which closed on 20 May 2019. The six Shallow Water Blocks are located off the north, west and east coasts of Trinidad. Bidders were required to propose for all blocks, a 15 per cent carry for the state in the first six years of the exploration period. Successful bids are expected to be announced six months after the close of bidding.

13 Clause 11(1)(d) of the Petroleum Regulations (Shallow Water Competitive Bidding) Order, 2018, as amended by the Petroleum Regulations (Shallow Water Competitive Bidding) (Amendment) Order, 2019.
In 2018, the government announced its decision to restructure Petrotrin’s operations. By virtue of the Miscellaneous Provisions (Heritage Petroleum, Paria Fuel Trading and Guaracara Refining Vesting) Act 2018, effective 1 December 2018, Petrotrin’s assets were transferred to three affiliated companies. Heritage Petroleum Company Limited became vested with Petrotrin’s exploration and production assets, Paria Fuel Trading Company Limited with terminalling assets and the Guaracara Refining Company Limited with refinery assets.
Chapter 26

UNITED KINGDOM

Michael Burns and Caroline Durran

I INTRODUCTION

The oil and gas industry in the UK is in a period of transition – adapting to a changing energy landscape, driven by the need to move towards a lower carbon economy, and evolving to address the realities of the UK continental shelf (UKCS) as a mature and complex basin. These driving factors have shaped trends in the UK oil and gas industry’s transactional and operating landscapes over recent years, as well as informing a number of recent legislative developments – in particular relating to innovation, decommissioning and ‘decarbonisation’ initiatives.

The UKCS still represents a significant resource in terms of both current production and future potential. It has the largest production capacity in the EU, and the second largest in the EEA after Norway. Although production trends are forecast to return to a position of decline in the early 2020s, there are still areas of significant growth potential within the basin, primarily west of Shetland, an area characterised by challenging conditions and limited existing infrastructure. In implementing its formal ‘maximising economic recovery’ (MER UK) strategy, described in more detail below, the UK Oil & Gas Authority (OGA) has encouraged an approach of ‘right assets, right hands’ – ensuring that assets (as investment opportunities) are in the most appropriate hands as a key enabler in the drive to maximise economic recovery. While pursuing the MER UK strategy, the OGA supports the transition to a low carbon economy, and works collaboratively with industry, government and others to harness the necessary expertise, skills and infrastructure of the UK oil and gas sector to help achieve it. The oil and gas industry has a vital role to play in this transition and will continue to provide the majority of energy needs, both in the UK and globally, for at least the medium term.

While deal activity during 2018 did not quite reach the levels seen in 2017, there were a number of significant M&A transactions within the UKCS in 2018 year and moving towards an increase within the first half of 2019. Total M&A spend for 2018 reached approximately US$5.6 billion, with 22 assets changing hands. M&A spend for upstream deals announced in the first half of 2019 alone has reached over US$4.5 billion. A variety of transactions occurred across all stages of the upstream oil and gas life cycle, including

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5 http://www.mergermarket.com [Mergermarket deal reporting].
exploration prospects, pre-development opportunities, producing fields and late-life assets. ‘Right assets, right hands’ – having investment opportunities in the most appropriate hands, is a key enabler in the drive to maximise economic recovery. Recent transactions have resulted in a more diverse corporate landscape on the UKCS, with the largest 10 companies accounting for just over half of production in 2018, compared with more than two-thirds of production in 2008. A significant trend continuing to develop during 2018 and into 2019 is the increasing proportion of UK assets, production and investment opportunities that are owned by private equity-backed companies. A number of these companies over the past two years have increased their exposure to the UKCS across various asset classes including the whole upstream life cycle, and particularly in the midstream sector. Private equity funds are generally able to view investment opportunities with a different focus to previous ‘traditional’ owners, given their different investment time horizons and freedom from immediate market pressures, and are able to adopt a flexible and efficient approach to maximise the value of their operations and investments.

The UKCS basin retains significant resources and a continued focus on exploration and development of new fields. Many exciting prospects continue to be developed, and production has been on the upswing. Nine new Field Development Plans were approved by the OGA in 2018. Total production from the UKCS was around 619 million boe in 2018, or 1.7 million boe per day, representing a total 20 per cent increase over the past five years. The OGAs estimate for proven and probable UK reserves as at the end of 2018 is 5.5 billion boe, slightly higher than as at the end of 2017 despite a year’s production. The UKCS still retains over 10 to 20 billion barrels yet to be produced. On the basis of current production projections, this could sustain production from the UKCS for another 20 years or more.

II LEGAL AND REGULATORY FRAMEWORK

The principal legislation governing oil and gas exploration and production of crude oil, gas and shale gas in the UK is the Petroleum Act 1998 (as amended) (the Petroleum Act). The Petroleum Act governs all oil and gas exploration and production in the UK (other than onshore in Northern Ireland), and underpins a regime whereby licences are granted, by the OGA (and by the Welsh Ministers, for onshore oil and gas in Wales, and the Scottish Ministers, for onshore oil and gas in Scotland), to persons to ‘search and bore for and get’ petroleum. Licence holders are granted the right to explore and develop a specified geographical area. Ownership of petroleum vests in the Crown, and petroleum produced within the licence area transfers from the Crown to the licence holder at the well head. The licensing regime, and the rights and obligations of the licence holder, are set out in more detail in Section III.

The Petroleum Act is supplemented by the Energy Act 2016, the Infrastructure Act 2015 and various environmental and health and safety legislative provisions (set out in more detail in Section VII).

7 https://www.ogauthority.co.uk/media/5942/oga_reserves__resources_report_2019_jk.pdf.
8 Reserves that are not yet proven, but which are estimated to have a better than 50 per cent chance of being technically and commercially producible.
The Department for Business Energy and Industrial Strategy (BEIS) is responsible for setting energy and climate change mitigation policies, and establishing the framework for achieving the policy goals in those areas.

From 1 October 2016, pursuant to the Energy Act 2016, the OGA was formally established as a fully independent regulator and a government-owned company, with the Secretary of State for Business, Energy and Industrial Strategy (the Secretary of State) as the sole shareholder. The Secretary of State is ultimately responsible to Parliament for the OGA.

The OGA is the entity responsible for petroleum licensing and regulation of the upstream oil and gas sector, including:

a) oil and gas licensing;
b) oil and gas exploration and production;
c) oil and gas fields and wells;
d) oil and gas infrastructure; and
e) carbon storage licensing.

In response to the decline in production from the UKCS, the UK government commissioned a review of the UK offshore oil and gas recovery and regulation led by Sir Ian Wood. The concluding recommendations of this review made various recommendations, including the establishment of a new regulator (the OGA, as noted above). The key principle of the recommendations, and the stated policy of the UK government, is to maximise the cost-effective recovery of UK resources (MER UK). The Infrastructure Act 2015 amended the Petroleum Act, to implement an official MER UK strategy, which was produced by the Secretary of State and came into force in March 2016. The MER UK strategy is binding on the OGA, various industry participants, the Secretary of State and licence holders, operators and owners of offshore installations. The OGA has enforcement powers in respect of compliance with MER UK, and it is required to act in accordance with its MER UK strategy when:

a) exercising its functions under the Petroleum Act or part 2 of the Energy Act 2016;
b) exercising functions or powers under a petroleum licence; and
c) using its ancillary powers, for example, to assist or advise the government.

III LICENSING

The Petroleum Act vests all rights to petroleum in the Crown but permits the OGA to grant licences to ‘search and bore for and get’ petroleum to persons deemed fit. Under the Petroleum Act, exploration for and production of petroleum in the UK and on the UKCS can only be undertaken under the terms of these licences. A company wishing to participate in the UK upstream oil and gas sector must bid for a licence or acquire an interest in existing assets, with any acquisition being subject to regulatory consents.

The OGA is now responsible for issuing licences through competitive licensing rounds that generally take place every year, and the MER UK strategy is applied by the OGA in each licensing round. Separate rounds are held for seaward (offshore) licences and landward (onshore) licences. In exceptional circumstances, where there are compelling reasons, the OGA may issue a licence outside of a licensing round. The OGA can only accept licence applications in response to a formal invitation to apply for a licence, so a company seeking an out-of-round licence must make a case to the OGA that out-of-round applications are justified.

Licences take the form of a deed, pursuant to which the licensee is bound to observe the conditions of the licence. These detailed terms and conditions are prescribed in a series
of ‘Model Clauses’, which are set out in secondary legislation under the Petroleum Act. The model clauses applicable to a particular licence are those that are in force at the time the licence was granted, and are not affected by subsequent sets of model clauses, except through specifically retrospective measures.

UK licences are both contractual and regulatory in nature – contractually, being executed as a deed and providing for the contractual transfer of rights from the Crown to the licensee, and regulatory, because the model clauses are encompassed in statutory regulations, and Parliament may unilaterally amend the terms upon which a licence is granted. Legally, only one licence exists, although a licence may be granted to one or more licensees, who will be held jointly and severally liable in respect of obligations arising under the licence.

The Petroleum Licensing (Applications) Regulations 2015 contain the application process for licences. All applications must be made in the prescribed form and for a specific area. The OGA will only grant a licence to an entity that has the appropriate technical and financial capacity to contribute to the MER UK strategy. The OGA considers all applications on an individual basis, and companies must meet certain criteria, including technical competence, financial capacity and tax considerations (the OGA routinely corresponds with HMRC for information on any tax issues). Prospective licensees must also satisfy the OGA that they have a place of business in the UK, meaning they must have either a staffed presence in the UK, be a UK company or have a UK branch of a foreign company.

The different types of licences currently being issued are:

a seaward production licences: These are the main offshore production licence, which run for three successive periods or terms. The initial term is associated with exploration, the second with development and the third with production. However, the licence requires fulfilment of the relevant work programme, agreed with the OGA, before it can proceed from one term to the next – but a licensee who fulfils the required obligations and obtains the relevant consents quickly during the initial terms, will not be prevented from commencing production under the licence prior to the third term. Production licences expire automatically at the end of the term unless the licensee has advanced the work programme sufficiently to commence the next term. The licence will expire at the end of its initial term unless varied by agreement, or the licensee has completed the work programme, all sums have been paid, and the licensee has relinquished 50 per cent of the initial licence area. Each production licence also requires payment of an annual fee (known as rental), charged on an escalating basis for each square kilometre covered by the licence at that date, licensees to relinquish areas that are not being exploited;

b landward production licences: The onshore equivalent of seaward production licences as described above (and formerly referred to as petroleum exploration and development licences);

c offshore innovate licences: The innovate licence offers greater flexibility during the initial and second term and an applicant for an ‘innovate’ licence can propose the durations of the initial and second terms. The ‘offshore innovate licence’ replaced the traditional, promote and frontier versions of the seaward production licence, described below (which still remain relevant for many existing offshore production licences); and

d exploration licences: An exploration licence is non-exclusive and covers the UK’s entire offshore area apart from those areas covered by any production licences that are in force at the time: These are commonly used by seismic contractors who gather data to sell rather than exploiting the resources themselves, or by holders of a production
licence who wish to explore outside the areas where they hold or require exclusive rights. The OGA grants both seaward (offshore) and landward (onshore) exploration licences. The annual payment is significantly lower than that of production licences and covers exploration relating to hydrocarbon production, gas storage, carbon capture and sequestration or any combination. An exploration licence grants rights to explore for petroleum, but not to extract it. It enables licence holders to carry out seismic surveys and to drill wells for core-sampling to a maximum depth of 350 metres below the seabed.

The ‘traditional, promote and frontier licences’ are no longer issued, but many remain in existence:

a) traditional licence. This was the most common type of offshore production licence. They were granted with licence term lengths of four years for the initial term to complete the initial work programme, following which the licensee was required to relinquish 50 per cent of its acreage to move to the next phase. The second term was for another four years, and finally reaching a production phase for an 18 year third term (other than in relation to the 27th and 28th licensing rounds where greater flexibility was introduced for certain licences);

b) promote licence. This licence was aimed at small and start-up companies. Applicants did not need to prove technical or environmental competence or financial capability before the award of the licence, but they were required to do so within two years of the start date of the licence. Otherwise, the terms of the various phases and relinquishment obligations were the same as a traditional licence

c) frontier licence. This licence had an exploration phase of six years to allow companies to evaluate larger areas and look for a wider range of prospects, but the terms varied based on the terrain (two more years for standard frontier licences and five additional years for the more challenging West of Shetland frontier licences). Licensees are required to relinquish 75 per cent of the acreage at the end of the third year of the initial exploration phase, and a further 50 per cent at the end of the initial exploration phase.

On 11 July 2019, the 32nd UK Offshore Licensing Round officially opened, inviting applications for licences up to 12 November 2019. A total of 796 blocks or part-blocks on offer across the main producing areas of the UKCS with acreage are on offer in the Central North Sea, Northern North Sea, Southern North Sea and the West of Shetlands.

IV PRODUCTION RESTRICTIONS

There is no national oil company in the UK that is directly involved in oil and gas exploration and production activities in the UKCS. Oil and gas exploration and production are regulated by restrictions on the award and transfer of licences, and requirements relating to approval of work programmes and how that work is performed. There are no special regulatory requirements that apply to the exports of oil or oil products, other than the payment of applicable duties or taxes, and compliance with EU oil stocking obligations. In the event of an actual or threatened emergency in the UK that will affect fuel supplies, the Secretary of State may use emergency powers under the Energy Act 2016 to regulate or prohibit the production, supply, acquisition or use of substances used as fuel.
V ASSIGNMENTS OF INTERESTS

The OGA’s consent is required for a licence to be sold, transferred, assigned or otherwise dealt. Any transaction that results in a company joining a licence, or withdrawing from a licence, is deemed to be a licence assignment. The OGA will consider any assignment made without prior consent, a very serious breach of the model clauses and grounds for immediate revocation of the licence or to reverse the assignment. There are a number of issues that the OGA considers when deciding whether to give approval, including: compliance with the EU 2013 Offshore Safety Directive, the technical and financial capacity of the assignee, decommissioning costs, effect on operatorship arrangements and fragmentation of licence interests (i.e., creation of less than 5 percent interests).

The company selling its licence interest (the transferor) must apply to the OGA for its consent. The transferor will need to obtain much of the information the OGA needs from the acquiring company (the transferee). Consent will not be granted unless the OGA has all required information. The OGA reviews and considers the form of the deed of assignment used by the parties, and provides for approved draft deeds of assignment. Licence assignment applications are processed online through the UK Energy Portal, and the OGA aims to process applications within 10 working days. If the assignment results in a change of operatorship, this may extend the process to as long as 30 working days. Assignment consents are valid for 90 days after the completion date specified in the application form.

While the model clauses or other applicable legislation do not expressly require the OGA’s consent to proceed with a change of control of a licensee, the OGA does have the power to require either a further change of control, or revocation of the licence, upon a change of control. As a result, best practice is to apply to the OGA in advance of a change of control, and seek comfort that the OGA will not exercise its powers. The application should demonstrate that the proposed change of control would not impact the ability of the licence holder to meet its obligations under the licence. The OGA may require a parent company guarantee from the new corporate parent to replace any existing parent company guarantee that may have been issued before the change in control.

The creation of a charge on a licence also requires the consent of the OGA. To facilitate ordinary course transaction financing, and to eliminate the cumbersome need for prior consent, ‘open permission’, which is a form of automatic consent, applies to any fixed or floating charge or debenture. The licensee must give notice to the OGA within 10 days of creation of the charge, providing certain information about the charge. If the holder of a charge intends to enforce the security interest, it will be caught as a licence assignment, and the procedures described above in respect of licence assignments will apply.

VI TAX

The tax system applicable to oil and gas related activities in the UK (and the UKCS) consists of a special fiscal regime, comprising three principal elements:

1. **Ring fence corporation tax (RFCT):** The normal corporation tax regime is modified in its application to companies producing oil in the UK and UKCS: a ‘ring fence’ applies to prevent taxable profits from oil and gas extraction from being reduced by losses from other activities. The rate of RFCT is currently 30 per cent. Despite the recent and prospective cuts in the main rate of corporation tax, the rate will remain at 30 per cent for profits from oil extraction in the UK and the UKCS;
supplementary charge (SC): This is 10 per cent with effect from 1 January 2016 (previously 20 per cent). This is not strictly corporation tax, but is charged as if it were an amount of corporation tax on ring fence profits to which financing costs are added back (and is subject to an allowance regime designed to encourage investment); and

petroleum revenue tax (PRT): This is an additional level of tax on the profits derived from particular fields. The rate of PRT was reduced to zero with respect to chargeable periods ending after 31 December 2015 but it has not been abolished so losses can be carried back against past PRT payments.

Following the effective abolition of PRT, RFCT and SC together result in an effective marginal tax rate of 40 per cent for all oil and gas fields in the North Sea.

Investment in the UKCS is encouraged by tax relief being provided for expenditure on research, exploration, appraisal and production, either through capital allowances (broadly, the UK’s form of allowable ‘tax’ depreciation) and also, once production has commenced, through tax deductions for expenses incurred wholly and exclusively for the purposes of an eligible trade. The government has also signed decommissioning relief deeds with oil and gas companies to provide certainty on the tax relief they will receive when decommissioning assets, as further described below.

In the context of UKCS transactions, decommissioning issues, and particularly the question of with whom the economic burden of decommissioning liabilities should lie, have frequently been a significant challenge to transactions involving the transfer of UKCS licence interests. The traditional position has been that buyers would provide sellers with an indemnity for all decommissioning liabilities whether they arise on or before the agreed economic date or date of the agreement.

There has been, however, an increasing trend toward sellers of licence interests retaining a proportion of the decommissioning liability (as historically, it was likely that the new owners would not be able to get effective tax relief for decommissioning costs, due to having paid insufficient amounts of corporation tax and SC by the time the decommissioning of those assets occurred). This has been particularly relevant in the context of late-life assets where a seller is likely to have significantly greater tax capacity than a buyer. However, in the context of ‘right assets, right hands’ and the MER UK strategy, following an announcement in the Autumn 2017 Budget, the Finance Act 2019 introduced transferable tax histories (TTHs) for oil and gas companies, which provide companies buying North Sea oil and gas fields with certainty that they will get tax relief for the decommissioning of the asset as, on purchasing the asset, they will be able to make a joint election for the buyer to acquire some of the previous owner’s tax history (namely historic profits on which ring-fenced corporation tax and supplementary charge have been paid). The buyer will then be able to set the costs of decommissioning the fields at the end of their lives against the TTH. The measure applies to licence transfers that receive OGA approval on or after 1 November 2018.

The recent amendments enacted are beneficial for a number of UKCS participants including:

- taxpayers selling licence interests who may be able to dispose of UKCS assets and thereby unlock capital to be employed in further exploration and development activity (whether in the UK or elsewhere) if a transaction can be structured such that the seller’s TTH is transferred to the buyer; and

- buyers of such assets who may have greater certainty that tax relief will be obtained for the cost of decommissioning activity.
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact and safety

While oil and gas exploration, development and production is primarily regulated by the licence and the Petroleum Act, various other statutory provisions apply in respect of environmental issues. The Model Clauses also generally require licensees to operate in accordance with 'good oilfield practice' and to take all steps practicable in order to prevent the escape or waste of petroleum, including into any waters in or near the vicinity of the licensed area.

The principal regulators for HSE in the UKCS are BEIS, the Health and Safety Executive, and a partnership between the two – the Offshore Safety Directive Regulator (OSDR), established in 2014 pursuant to the European Commission Offshore Safety Directive (2013/30/EU) (the 2013 Directive), which itself was a direct response to the Deepwater Horizon disaster in 2010. The European Commission is currently assessing whether the 2013 Directive, applicable in the UK, has achieved its objective of ensuring safe offshore oil and gas operations, pursuant to an evaluation planned to be completed and released in the third quarter of 2019.

Following the Piper Alpha offshore platform explosion in 1988, and the subsequent Cullen Inquiry, the UK developed the Offshore Installations (Safety Case) Regulations 2005 (followed by the Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015), which impose obligations on the operator to prepare safety cases and risk assessments to be approved by the Health and Safety Executive for all offshore installations.

The OGA has the power to issue financial penalty notices carrying fines of up to £1 million under the Energy Act 2016, in respect of: (1) a failure to act in accordance with the MER UK strategy; (2) a breach of a condition of an offshore licence, or (3) other breaches of the Energy Act 2016 that are sanctionable thereunder. It may also order the removal of the operator of a licence and ultimately revoke a licence for one or all of the licence holders in the event of non-compliance with applicable requirements.

The Offshore Petroleum Regulator for Environment & Decommissioning (OPRED), an agency of BEIS, is principally responsible for enforcing the environmental regime applicable to offshore oil and gas activities (and also decommissioning) in the UK. The UK government has recently enacted the Offshore Environmental Civil Sanctions Regulations 2018 (the OECS Regulations) to allow OPRED to impose civil sanctions in respect of breaches of some existing offshore oil and gas environmental regulations. Previously, the breaches could only be sanctioned through criminal prosecution. As noted in the UK government’s January 2018 consultation in relation to the proposals, while criminal prosecutions can result in substantial financial penalties being imposed by the criminal courts, this process is ‘slow, resource intensive and costly’. The UK government considers that the new civil sanctions will provide OPRED with ‘a more flexible, proportionate and timely enforcement response in respect of breaches that amount to criminal offences’. It is relevant to note that the new civil sanctions will only apply to breaches that can currently be subject to criminal prosecution, and as such, the OECS Regulations do not create any new offences – only an alternative means for OPRED to sanction these breaches. OPRED can impose a penalty in circumstances where it is satisfied that a breach has been proven beyond reasonable doubt (the criminal burden of proof).
These new civil penalties will apply to offences under the following regulations, being the key UK regulations relating to the offshore oil and gas industry:

- the Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013;
- the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005;
- the Offshore Installations (Emergency Pollution Control) Regulations 2002;
- the Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998; and
- the Offshore Chemicals Regulations 2002.

In the event of an oil spill in UKCS waters, the licensees will have unlimited liability for all remediation under the EU Environmental Liability Directive (2004/35/EC). In addition to a licensee’s remediation obligations, under English law, liabilities may arise under other torts such as nuisance and negligence. Otherwise, licensees suffering damage caused by operations of an offshore installation may claim under a voluntary oil pollution compensation agreement to which all offshore operators active in the UKCS are party. Membership of the offshore pollution liability agreement (OPOL), is a condition of OGA granting a licence and so all operators will in practice be party. OPOL subjects operators to strict liability for pollution damage, and the cost of remedial measures up to a maximum of US$250 million per incident.

### ii Decommissioning

Oil and gas operators in the UK are increasingly decommissioning their assets as they are reaching the end of their useful economic lives. Operators’ expenditure on decommissioning is rising: they have spent more than £1 billion on decommissioning in each year since 2014.10

The Petroleum Act imposes an obligation on licensees to pay for the decommissioning and proper removal of offshore installations from the seabed, other than in exceptional circumstances. Decommissioning of these installations (including pipelines) is regulated by BEIS, through OPRED. The OGA, pursuant to MER UK and the Energy Act 2016, is required to assess decommissioning programmes to ensure they meet the MER UK principal objectives on the basis of cost savings, future alternative use and collaboration.

The Secretary of State, under Section 29 of the Petroleum Act, has the power to serve a ‘Section 29 Notice’ to anyone owning an ‘interest’ in an installation ‘otherwise than as security for a loan’ and associated companies (broadly 50 per cent owned direct or indirect affiliates) of companies that are directly liable. The Section 29 Notice will either specify the date by which a decommissioning programme for each installation or pipeline is to be submitted or, as is more usual, provide for it to be submitted on or before such date as the Secretary of State may direct. At first instance a Section 29 Notice would typically be issued to the operator of the field and each of the licensees, but the power of Secretary of State to issue a Section 29 Notice to other relevant parties is broad, and should be considered in transaction structures in an M&A context. It is expected that the OGA will send a Section 29 Notice to this wider class of parties if it finds the decommissioning arrangements proposed by the operator and licensees to be unsatisfactory.

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The Secretary of State has the power to withdraw Section 29 Notices, for example, in respect of withdrawing licensees, but it would be unusual for this to occur without a replacement notice to be serviced on an incoming licensee. Additionally, BEIS has the power to reissue any Section 29 Notice (under Section 34 of the Petroleum Act) – it is important to note that the risk of a licensee (or other interested party or related person as set out above) re-incurring liability is always present, and they may be potentially liable for the decommissioning of that field until decommissioning is complete.

The Section 29 Notice requires the recipient to submit a decommissioning programme (setting out the methods and measures to decommission disused installations or pipelines, or both). Once the decommissioning programme is approved, following the OGA’s review of the details including the cost estimates, the notice holders are legally obliged to carry it out on a joint and several liability basis. If a programme is not carried out or its conditions are not complied with, the Secretary of State may, by written notice, require remedial action to be taken. Failure to comply with any such notice is an offence, and the Secretary of State can carry out the remedial action and recover the costs from the person to whom the notice was given.

The Secretary of State can require decommissioning security at any time, with the security being ring-fenced from creditors in an insolvency situation, if it believes that there is an unacceptable level of risk of decommissioning costs falling to government. The industry and the regulators have developed the Oil and Gas UK Decommissioning Security Agreement, which is the form of security commonly entered into by all licensees, providing for security to be held on trust by an independent security trustee. This security may be provided by a standby letter of credit, performance bond or insurance product, or cash (but may not be a parent company guarantee).

To date, OPRED has agreed nine security agreements with operators, and a total of £844 million has been set aside for decommissioning. OPRED monitors the financial health of operators to determine their financial position compared with their anticipated costs to decommission assets. For example, it assesses operators’ ratio of assets to liabilities in their accounts and has access to data provided by a consultancy firm on operators’ financial health.

In response to concern that a lack of certainty about decommissioning tax relief had led operators to set aside money for decommissioning on a pre-tax (rather than post-tax) basis, in 2013, HM Treasury introduced decommissioning relief deeds to give operators greater certainty about the tax relief they will receive for decommissioning. These deeds guarantee that tax relief for decommissioning will not be lower than under 2013 rules and provide certainty that operators will receive tax relief should they incur any additional decommissioning costs due to the default of another party. The rationale is that this will reduce the amount of security required (before security was given without taking account of tax relief, therefore, increasing the amount), which will free up funds for asset transactions and investments, and discourage early decommissioning.

VIII CURRENT DEVELOPMENTS

i UKCS in transition: decommissioning as part of the value chain

Both government and industry are facing the changing circumstance of the ‘energy transition’ – driven by economic, geological and political realities. As assets age and we push towards a lower carbon economy, increasingly government and industry are aligned and seeking to ensure that decommissioning is not (and is not seen as) solely a loss-making, mandatory action.

In the spring of 2019, the UK government completed a consultation on ‘Strengthening the UK’s offshore oil and gas decommissioning industry’, focusing in large part on building on existing fiscal, policy and collaborative measures, how the UK decommissioning industry could further improve its ability to serve the UK market, support MER UK and reduce the overall costs of decommissioning. The TTH, introduced in 2018, as described above, allows companies selling UKCS interests to transfer tax payment history to the buyer. The buyer will then be able to set the costs of decommissioning the fields at the end of their lives against the TTH, incentivising bringing new investors (and new capital) into the arena who may not previously have been able to benefit.

A particularly exciting and innovative initiative on the legislative horizon that would also create value through decommissioning is the potential for the reuse of existing end-of-life oil and gas infrastructure for carbon capture usage and storage (CCUS) projects. The reuse of existing oil and gas infrastructure for CCUS could present a significant opportunity to reduce costs for initial projects. The UK government has committed to a ‘CCUS Action Plan’ including a commitment to deliver the UK’s first CCUS project from the mid-2020s. A public consultation completed in the fall of 2019 sought input on:

a identification of existing oil and gas infrastructure that has the potential for reuse and to develop a policy to support the development of CCUS in the UK;

b whether government should introduce a discretionary power for the Secretary of State to remove the decommissioning liability from previous oil and gas asset owners if assets are transferred to CCUS projects; and

c changing guidance from the OGA and government to encourage owners and operators of oil and gas assets to propose a period of suspension prior to decommissioning in circumstances in which there is a reasonable prospect of the asset being acquired by a CCUS project.

ii Brexit

While from a regulatory perspective, it is not certain that Brexit would have a significant impact on the UK upstream oil and gas regulatory regime, as it is highly developed independently of EU law, the impact of Brexit would almost certainly be felt across the industry commercially and financially due to overall economic uncertainty. Depending on the terms of any potential Brexit, the industry could be exposed to additional tariffs and the restrictions on the import of goods and services.
FERDINAND ADADZI

AB & David

Ferdinand is a partner at AB & David, a multi-specialist law firm practising in Africa, and a lecturer at GIMPA Faculty of Law. Ferdinand graduated from the University of Ghana with a first-class honours in bachelor of laws (LLB) and also holds a master of law (LLM) degree from the University of Alberta, Canada. He is a solicitor and barrister specialising in corporate transaction and project advisory services as well and energy, oil and gas. Ferdinand was involved in advising one of the Jubilee partners on the unitisation requirements and tax-related matters on the Jubilee field as well as other oil and gas transactions.

Ferdinand’s interest is in transactional advisory services related to corporate transactions, infrastructure, public-private partnership, extractive industry, project finance and energy. He currently leads the firm’s procurement, PFIs, PPPs and infrastructure, and energy, mining, oil and gas practices. He is also recognised as a leading lawyer in procurement and energy by Who's Who Legal.

LAURA ALAKIJA

Primera Africa Legal

Laura is deputy managing partner in Lagos and partner overseeing commercial transactions at Primera Africa Legal. She has a flair for deal structuring in complex commercial transactions and has provided negotiation, documentation and legal advisory support to client transactions across various sectors including energy and natural resources, infrastructure and real estate, hospitality, technology and communication, transportation and project finance. She is also team lead of the firm’s corporate law group and has led the team in providing compliance, governance, secretarial services, business restructuring, permitting and licensing support to our clients.

Laura has an LLM in transnational oil, gas and energy law from the University of Derby, UK. She joined Primera Africa Legal in June 2010 and was a member of faculty of the Centre for Law and Business, a registered centre of the University of London International Programmes from 2009 to 2010.

Laura’s early career was in online legal research and establishment of digital libraries for institutions.
PABLO ALLIANI
Alliani & Bruzzon

Pablo J Alliani is a partner in Alliani & Bruzzon. He leads the firm’s international energy practice and has represented international and domestic clients. He has counselled international oil and gas majors, independent companies and utilities in oil and gas contracts negotiations, regulatory matters, M&A and on new infrastructure projects. As an example of his representations, Mr Alliani assisted one of the oil and gas majors in the largest development in Vaca Muerta so far. Mr Alliani was chair of the Section on Energy, Environment, Natural Resources and Infrastructure Law (SEERIL) of the International Bar Association (IBA). He was the president of the Association of International Petroleum Negotiators (AIPN) during 2011–2012, and he served on the AIPN Board for 10 years. Mr Alliani holds a JD degree from University of Buenos Aires and an LLM from Southern Methodist University, and was a foreign visiting attorney with Baker Botts LLP.

FLORIAN AMERELLER
Amereller Legal Consultants

Dr Florian Amereller has spent the past 25 years in the Middle East representing a broad client base of primarily multinational companies on various aspects of business in the Middle East. He also represents some Arab governments and leading entrepreneurial families in the region. Florian Amereller is fluent in Arabic and a member of the Executive Board of the German-Arab Chamber of Commerce and Industry (Ghorfa), a board member of the German-Arab Chamber of Industry and Commerce, a founding board member of the Society for Arab and Islamic Law (Germany) and founder or member of various other European and international associations and expert committees for legal development and reform in the Arab world. In addition to his advisory work as a lawyer, Florian Amereller frequently acts as sole arbitrator, co-arbitrator and chair in arbitration proceedings related to the Middle East. He also sits on the boards of a number of leading regional businesses. Florian Amereller holds a PhD and a LLM in Islamic law (Islamic banking) and has published extensively on Arab business law.

DJAMILA ANNAD
Gide Loyrette Nouel

Djamila Annad joined the Algiers’ office of Gide law firm in September 2015 as of counsel in charge of energy sector issues after being adviser to the Ministry of Energy for five years. Djamila spent three decades at Sonatrach, where she held various responsibilities monitoring the implementation of upstream projects by negotiating more than 20 production-sharing contracts governed by Law 86-14. In August 2010, she joined the Office of the Ministry for Energy, which she left in May 2015, as an adviser in charge of partnerships issues and was also a member of the team of experts in charge to amend the Hydrocarbons Law No. 05-07, which gave rise to Law No. 13-01. Djamila was primarily in charge of the development of the new hydrocarbons taxation.
ISRAEL AYE
Primera Africa Legal

Israel Aye is senior partner and chair of the energy desk at Primera Africa Legal. In addition to his roles at Primera Africa Legal, he is a director at the Aspen Energy Nigeria (Energy Services and Consulting) Group and faculty member of the International Law Institute – African Centre of Excellence (ILI-ACLE), where he provides training on oil and gas contracting for participants from around Africa.

He has featured in Who’s Who Legal as a specialist in the natural resources, energy, oil and gas sector since 2012 and is an accredited mediator, Centre for Effective Dispute Resolution UK (CEDR) and a member (MCIArb) of the Chartered Institute of Arbitrators (UK and Nigerian Chapter).

Prior to joining Primera Africa Legal in 2010, Israel was in-house at Shell Nigeria for over a decade. While at Shell, he provided hands-on legal advice and support to transactions and projects in the upstream, midstream and downstream aspects of Shell’s business in Nigeria.

JEAN-PIERRE BOZEC
Project Lawyers

Jean-Pierre is an authorised and registered legal advisor in Gabon and remains registered as an avocat at the Paris Bar (France) with 22 years’ experience in African transactions, 17 of those years resident in Gabon.

Jean-Pierre has wide experience of projects and project financing throughout North, West and Central Africa, in particular as far as energy and mineral resources are concerned. Over the course of his career, he has developed a strong expertise in negotiation and drafting state contracts (production sharing contracts, establishment convention, mining conventions, BOT and concession agreements), in legal and tax structuring of projects in Africa, in particular for oil and gas, utilities, transportation infrastructures and mines. He graduated from Exeter University (UK) with an LLM in international business transactions and from Rennes University (France) with a postgraduate degree in business law.

The leading experience of Jean-Pierre Bozec in Gabon has been consistently recognised by Chambers Global, The World’s Leading Lawyers, The International Who’s Who of Energy Lawyers 2019 and others.

FERNANDO BRUNELLI

*Alliani & Bruzzon*

Fernando L Brunelli was born in Buenos Aires, Argentina on 24 December 1970. He was admitted to the Bar in Argentina in 1994. He graduated from Belgrano University (JD, 1994), Austral University (postgraduate corporate law, 1996) and the University of Buenos Aires (postgraduate oil and gas law, 1998).

Mr Brunelli joined Alliani & Bruzzon in 1997, was a foreign visiting attorney at Gardere & Wynne, LLP's Houston Office, Texas) in 1999 and became a partner at Alliani & Bruzzon in 2005. Since his joining the firm, he has worked on several oil and gas-related transactions, including mergers and acquisitions, purchase and sale of assets, assignment and farm-in agreements, joint ventures, oilfield services agreements and participation in bidding rounds, assisting international and local E&P and services companies.

He is a member of the Buenos Aires Bar Association and is fluent in Spanish and English.

MICHAEL BURNS

*Ashurst*

Michael is a partner who specialises in mergers and acquisitions, joint ventures and major project development with a focus on the energy sector (in particular oil and gas and power).

His clients include multinational corporates, financial institutions, governments and individuals. Michael is a committee member of the International Bar Association's UK Energy Lawyers Group.

OLIVIER BUSTIN

*Vieira de Almeida*

Olivier is managing international adviser of the OHADA jurisdictions practice where he has been involved in several transactions. His practice is focused on production sharing contract negotiations, mergers and acquisitions, finance, public-private partnerships and infrastructure projects mainly in connection with the Energy and Natural Resources Sector in Francophone Africa.

He has been a visiting professor in the postgraduate study on OHADA Law, jointly organised by the Paris 2 and Paris 13 Universities, where he has been providing courses on various supranational legal frameworks applicable in Africa, like the Central African Economic and Monetary Community (CEMAC) Law, the West African Economic and Monetary Union (UEMOA) Law, the Common Market for Eastern and Southern Africa (COMESA) Law, the Economic Community of West African States (ECOWAS) Law, the Inter-African Conference on Insurance Markets (CIMA) Law and the African Intellectual Property Organization (OAPI) Law. He has also been a visiting professor at the Bel Campus University in Kinshasa, where he has been teaching the debt recovery procedures and enforcement procedures. Previously, and for eight years, Olivier taught contract law, European business law, sureties and security interests, probate and property law in several French Universities (Paris 2, Paris 13, Sciences-Po Paris). Olivier is admitted to the Paris Bar Association, the Portuguese Bar Association and the Kinshasa/Matete Bar Association (Democratic Republic of the Congo).
YNGVE BUSTNESLI

*Kvale Advokatfirma DA*

Yngve Bustnesli is a partner at Kvale Advokatfirma DA. He is rated as one of the leading Norwegian practitioners within the regulatory framework (e.g., petroleum law, HSE regulations and environmental law), oil and gas transactions, offshore projects (e.g., fabrication contracts), offshore contracts (e.g., drilling and rig contracts), gas sales contracts and the decommissioning of offshore installations.

In his former position as a legal adviser at the Ministry of Petroleum and Energy, he participated, inter alia, in preparing the Petroleum Act with regulations and amendments to the joint venture agreements. Yngve also participated in the team working on the partial privatisation of Statoil and the establishment of the public corporations, Petoro and Gassco.

Yngve is a co-author of the standard textbook on Norwegian petroleum law, published in January 2010. He is also the author of the first Norwegian commentary (volumes 1 and 2) on legal sources applicable to the petroleum activities published in November 2013.

JAMES COMYN

*Hunton Andrews Kurth LLP*

James’s practice focuses on cross-border mergers and acquisitions, joint ventures and minority investments. Formerly based in Abu Dhabi and currently based in Dubai and London, he has extensive experience in advising government-owned entities in the Middle East on transactions with foreign partners and foreign partners investing in the countries of the Arabian Gulf, particularly in the oil and gas, healthcare and real estate industries. Additionally, James has advised on projects across Asia, Africa and Europe. James earned his LLB in 1994 from The London School of Economics and Political Science. He received his BA from the Université Laval in 1991, and spent one year at the Université de Paris.

SEBASTIÁN CORTEZ MERLO

*Noboa Peña & Torres Abogados*

Sebastian Cortez Merlo is a partner at the firm and leads the oil and gas and energy practices. He has extensive experience in major oil and gas and energy projects, as well as in complex corporate structuring and project finance related to these projects. He has advised clients in Ecuador’s largest recent oil and gas tenders and projects, and possesses deep transactional and regulatory expertise. Sebastian is also actively involved in complex disputes and litigation involving a wide range of matters, including oil and gas matters. Sebastian is a lawyer from Pontificia Universidad Católica del Ecuador in Quito and has an LLM from American University in Washington, DC (Fulbright scholar).

CLARO MANUEL COTES RICCIULLI

*Holland & Knight*

Claro M Cotes R is an associate in Holland & Knight’s Bogotá office. He practises in the area of oil and gas, mining, environmental, corporate and M&A as well as litigation and dispute resolution. Mr Cotes primarily represents oil and gas and mining companies as well
as other types of corporations. He advises clients on contracting, due diligence, and mergers and acquisition matters, and also has experience with litigation. Mr Cotes graduated from Universidad Javeriana and holds an LLM from Dundee University.

OLAOLUWA DUNTOYE
Primera Africa Legal
OlaOluwa is a managing associate in the corporate and commercial transactions department of Primera Africa Legal. Her interest span a wide range of practice areas and she regularly provides services to top industry clients in different sectors such as energy, finance, hospitality, building and construction, ICT, real estate and investment. She is adept at providing legal advice and opinions to clients including drafting and reviewing legal agreements.

CAROLINE DURRAN
Ashurst
Caroline is an associate with diverse experience on a range of matters in the energy and mining sectors, focusing on M&A as well as the commercial and operational agreements required to operate projects, including host state agreements, joint venture agreements and sales/offtake arrangements.

JOSÉ ROBERTO FAVERET CAVALCANTI
Faveret Lampert Advogados
José holds a law degree that was obtained from the Rio de Janeiro State University in 1986. He joined Villemor Amaral Advogados in 1986, where, for 25 years, he was the leader of the infrastructure and projects practices.

José holds more than 15 years of experience in the areas of energy and oil and gas, where he has represented Petrobras and many other state gas distributors in several structuring projects, greenfield developments, commercial agreements, funding structures (he has been a pioneer in representing Petrobras in project finance related to oil fields, floating production unities, natural gas pipelines, power plants and petrochemical plants), regulatory advisory matters and licensing.

As external counsel of Petrobras, he has led several projects and transactions that were landmarks for the foundation of the current format of the gas industry in Brazil.

Due to his vast experience in the oil and gas industry as Petrobras external legal counsel, he was invited in 2007 to take the position of general counsel of OGX Petróleo e Gás Participações SA.

ANDRÉ DUARTE FIGUEIRA
Cuatrecasas
André Duarte Figueira has been a senior associate at Cuatrecasas since 2017. He is head of the firm’s oil and gas department in Portugal. Between 2013 and 2017, he was head of legal affairs at Portfuel – Petróleos e Gás de Portugal, Lda, and legal manager at the US company Petro Lions, LLC.

He developed his career in international tax planning, particularly regarding double taxation agreements between Portugal and the US.
In the US, he was involved in the entire process of creating and approving the oil-and-gas operator Petro Lions, LLC, together with the competent institutions, including the IRS – Internal Revenue Service – and the Texas Railroad Commission. In the field of oil and gas, he participated in the negotiation of various international agreements, particularly in the US, with Schlumberger, High Sierra and Superior (mineral rights and lease negotiation, operating and participation agreements, farmouts and regulatory compliance).

In Portugal, he worked as head of legal affairs at Portfuel, Lda, during which he negotiated with the Portuguese state and obtained two concessions (Aljezur and Tavira) for the prospecting, operating and marketing of oil and gas in Portugal.

He has focused his activity on corporate law, participating in court and out-of-court conflict resolution in civil, administrative and tax matters.

PAUL FOLEY
*MinterEllisonRuddWatts*

Paul is a senior corporate and commercial consultant and head of the energy and resources team at MinterEllisonRuddWatts. He has extensive experience in the energy and resources sector, advising clients on a range of sector-related issues. The companies he acts for include oil exploration companies, energy retailers, coal miners, electricity regulators and financial service and product providers.

Paul has in-depth, practical experience as a non-executive director of listed oil exploration companies in New Zealand and Australia. He has acted on many of the largest transactions in the energy sector and has advised oil and gas companies on debt and equity capital raisings and also farm-ins, drilling contracts and gas sales agreements.

*Chambers Asia-Pacific (2015)* says: ‘Seasoned practitioner Paul Foley receives market-wide acclaim from clients who appreciate that he has “good commercial awareness”’.

NANA SERWAH GODSON-AMAMOO
*AB & David*

Nana Serwah is a partner at AB & David. Nana is a solicitor and barrister (qualified in Ghana) with significant experience in energy and natural resources, corporate and finance and government business and policy reform. She has advised on various key energy and oil and gas transactions and projects in Ghana including the recent acquisition of the Hess Corporation interest in the Deep Water Tano Cape Three Points licence by Aker Energy. She also consults on the development of industry legislation and is the practice coordinator for the firm’s oil and gas and government business and policy reform practice groups. Nana holds an LLB and an LLM in transnational commercial practice.

ANDREAS GUNST
*DLA Piper Weiss-Tessbach GmbH*

Andreas is an energy, projects and finance practitioner qualified in England and Wales, and is a partner at DLA Piper based in both the London and Vienna offices. He is head of the energy practice in Vienna, and his practice areas cover the entire energy value chain, including upstream oil and gas exploration, production, transportation and trading (both OTC and exchange) in Europe; as well as 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.

GUANLI HUANG  
*Zhong Lun Law Firm*  
Guanli Huang is an associate at Zhong Lun Law Firm.

SIMONNE JAGGERNAUTH  
*Fitzwilliam, Stone, Furness-Smith & Morgan*  
Simonne joined the firm in 2016 as an associate after four years in the office of the Director of Public Prosecutions where she gained valuable exposure as a state prosecutor and advocate. Simonne practices primarily in the firm’s litigation department both as an instructing and advocate attorney in a variety of civil matters including personal injury, debt collection, contract and tax disputes.

She works closely with Jon Paul Mouttet on tax matters and regularly appears before the Tax Appeal Board on behalf of taxpayers appealing against assessments by the Board of Inland Revenue.

DARRELL R JOHNSON  
*SSEK Legal Consultants*  
Darrell R Johnson has resided and practiced in Indonesia for 41 years. He has been the senior legal counsel of SSEK Legal Consultants since its founding in 1992 and is now its senior of counsel. Darrell works with international companies and large Indonesian firms and has a wealth of experience advising on large and complex transactions across numerous sectors. Darrell has represented major oil companies active in Indonesia, including ExxonMobil, Total, British Petroleum, ConocoPhillips, Chevron, Anadarko and Hess Corporation, among others. He has been active in the representation of a major US oil company in a joint venture project with Indonesia’s largest coal-bed methane company. Representative engagements include advising Indonesia’s state-owned oil and gas company on the acquisition of a stake in a petrochemical company, counselling Mobil Cepu on regulatory and land issues related to an oil and gas project in Java, and advising Exxon Natuna on regulatory issues pertaining to a multibillion-dollar oil and gas development. Darrell is a graduate of the University of Southern California and Stanford Law School, where he served on the Board of Editors of the Stanford Law Review. He is admitted to practise in California and the United States Supreme Court.

MANFRED KNIGHTS-FUERNKRANZ  
*DLA Piper Weiss-Tessbach GmbH*  
Manfred has worked in the energy sector for more than 10 years and has taken on various positions in legal departments. Currently he is business partner legal upstream of OMV Aktiengesellschaft. Manfred studied law in Vienna and Geneva. He started his career in the energy sector in the infrastructure segment, first as legal counsel of Baumgarten–Oberkappel Gasleitungsgesellschaft mbH (now merged into Gas Connect Austria GmbH) and later as
About the Authors

senior legal counsel in OMV Aktiengesellschaft where he was in charge of major European
gas infrastructure projects and also covered the upstream gas as well as the power sector
within OMV. With a secondment to EconGas GmbH, a company listed in the Top 10 of
Austria’s most successful companies in 2015, Manfred further deepened his professional
portfolio in the energy sector.

SAMY LAGHOUATI

Gide Loyrette Nouel

Samy is the managing partner of the Gide Algiers office, which he founded in 2004. Over
the last 10 years he has been involved in most of the major foreign investments in Algeria
(privatisations, acquisitions, joint ventures and financings) in various sectors, such as industry,
energy and water. Regarding energy, Samy counsels clients in a wide variety of transactions in
the energy, infrastructure, and natural resources industries, with a particular focus on project
development and mergers and acquisitions. His experience includes transactions relating to
upstream oil and gas, petrochemical plant and ammoniac projects. He also has a strong
practice in international arbitration in the oil and gas sector in Algeria.

MATTHIAS LANG

Bird & Bird LLP

Matthias Lang is a partner in Bird & Bird’s energy and utilities sector group and a member
of the regulatory and administrative practice group. Matthias heads the firm’s infrastructure
group. He studied economics at Hamburg School of Business Administration and was a
banker before he studied law in Trier and Geneva. He did his PhD in law at Humboldt
University in Berlin.

Matthias regularly advises clients on infrastructure, energy, regulatory, and environmental
law as well as issues arising from public commercial law. He has additional expertise in
corporate law, administrative, European and real estate law, as well as standardisation. Matthias
has extensive experience in advising clients on all aspects of the German energy
transition and cross-border energy issues, including both conventional and renewable energy
projects, as well planning and permit procedures for transmission and distribution systems
or other industrial installations. He has worked on numerous complex infrastructure projects
and transactions in regulated industries. He represents clients before the Federal Network
Agency, ministries and other authorities in diverse administrative, regulatory or legislative
proceedings, before national and European courts and in arbitration proceedings. He has also
advised on the transposition of European law, such as the Third Internal Market Package and
various European environmental directives and regulations.

Matthias teaches energy law courses at Free University Berlin and Technical University
Berlin. He is the immediate past chair of the oil and gas committee of the International Bar
Association and on the board of the German-American Lawyer’s Association (DAJV).

LAURA LINDE

Laura Linde is a former trainee of Bird & Bird’s energy and utilities sector group where
she focused on European energy and regulatory law. Laura has obtained an LLM in energy
and environmental law from the University of Connecticut in 2017. Prior to the LLM, she
completed her law degree at Free University of Berlin where she specialised in European Law and Public International Law. Currently, Laura is pursuing a Master of Public Policy at the Hertie School of Governance in Berlin where she focuses on energy policies.

**IVAN LAFAYETTE BANDEIRA LONDRES**  
_Faveret Lampert Advogados_  
Ivan's practice focuses on commercial transactions and regulatory work for the energy industry. In the past 15 years, Ivan has been involved in key projects in Brazil and internationally as well.

While abroad, he was able to expand his experience into other domains of the energy business, including upstream and power. Ivan received a full international scholarship and obtained an LLM degree in petroleum law and policy (distinction) from the University of Dundee. Professionally, he progressed towards an international career with Schlumberger in Qatar and as partner of CMS Cameron McKenna LLP in London.

Over the years, Ivan has developed a full set of legal and commercial skills in all levels of the oil and gas industry, allowing him to provide valuable transactional capability along with comprehensive regulatory advice.

From an academic perspective, he lectures on ‘upstream and natural gas contracts and policy’ in conferences and postgraduate courses. In addition, Ivan has had several articles and essays published in newspapers and online covering topics such as natural gas commercialisation, climate change policy and liberalisation of energy markets.

**FRANCISCO LARREA NARANJO**  
_Noboa Peña & Torres Abogados_  
Francisco Santiago Larrea Naranjo is a director at the firm and is an oil and gas and energy expert. He has advised clients in Ecuador’s largest tenders and new operations, and provides day to day advice to clients with oil and gas operations in Ecuador. His practice includes national and international litigation and arbitration in these fields. Francisco is a lawyer from the Pontificia Universidad Católica de Ecuador in Quito and has a master’s degree from Universidad San Francisco de Quito, and an LLM from Penn State University.

**YING LIU**  
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Ying Liu ia a senior associate at Zhong Lun Law Firm.

**LESLEY-ANN MARSANG**  
_Fitzwilliam, Stone, Furness-Smith & Morgan_  
Lesley-Ann is an associate and now practises exclusively in the firm's commercial department. She has an active practice in corporate and commercial law, particularly with the oil and gas and minerals industries, having been exposed to these areas in the public sector prior to joining the firm. She works closely with Jon Paul Mouttet on energy matters and has extensive experience with, among other things, PSC extensions, upstream and downstream due diligence, host government contracts, pipeline agreements, petrochemicals and upstream
sales and acquisitions. Lesley-Ann also regularly interacts and has developed cordial relationships with personnel employed in several state and private enterprises that operate in these industries.

MICHAEL MEYER

Gorrissen Federspiel

Michael Meyer has advised leading Danish energy companies for more than 25 years and has acted as lead counsel in numerous transactions involving energy companies. Michael Meyer has also acted as lead counsel in the setting up, divestiture and merger of activities in the electricity sector, including the establishment of Denmark’s largest photovoltaic facility and management of the power supply to a sizable data centre in Denmark. Further, Michael was involved in the establishment of the joint venture between Vestas Wind Systems A/S and Mitsubishi Heavy Industries. Finally, Michael Meyer has been engaged as adviser to various international energy companies in oil and gas transactions, including for projects involving the North Sea.

NATALYA MOROZOVA

Vinson & Elkins LLP

Natalya Morozova started at Vinson & Elkins in 1991. She was a highly respected practitioner for years, acting on complex international mergers and acquisitions, private equity investments, project development transactions, regulation of foreign investment and general corporate practice with the principal focus on the energy and natural resources sector. As of 1 January 2019, Natalya retired.

JON PAUL MOUTTET

Fitzwilliam, Stone, Furness-Smith & Morgan

Jon Paul is a partner in the firm’s commercial department. He was initially active in both the litigation and commercial departments but now focuses on commercial work, with the notable exception of tax, where he maintains a large tax litigation portfolio. Jon Paul has an active practice that focuses on industrial projects, petroleum and tax law.

His clients include, among others, international and local companies involved in oil and gas, industrial and manufacturing processes, power generation, quarrying, service companies and local conglomerates operating in various sectors. Jon Paul regularly provides advice on a wide range of core petroleum and petroleum-related issues, industrial matters (including foreign direct investment issues), tax, joint ventures, M&A transactions, industrial regulation (including HSE matters) and other commercial and corporate matters. In the course of his career, he advised on and acted in multiple prospective and actualised energy projects, including those involving gas sales, petroleum transportation issues, petroleum terminal optimisation, metals, LNG, CNG, polypropylene, polyethylene and petrochemicals. He also regularly represents both local and international clients before the Tax Appeal Board on contentious appeals against assessments made by the Board of Inland Revenue.

Jon Paul’s work often involves significant interface with personnel at the Ministry of Energy and Energy Industries, the Heritage Petroleum Company Limited, the National
Energy Corporation of Trinidad and Tobago Limited, The National Gas Company of Trinidad and Tobago Limited and the Board of Inland Revenue, and he enjoys a good working relationship with the various personnel at these state institutions and companies.

Jon Paul is also recognised in Chambers Global, World’s Leading Lawyers for Business, having first been recognised while he was still an associate.

UCHE ODIGILI
Primera Africa Legal
Uche is an associate in Primera Africa Legal’s energy and commercial transactions department. His experience includes advising corporate transactions, including mergers and acquisitions, private equity investments, oil and gas matters, project finance and general corporate advisory.

DIOGO ORTIGÃO RAMOS
Cuatrecasas
Diogo Ortigão Ramos joined Cuatrecasas, Gonçalves Pereira in 1996 as an associate. He became a partner in 2000. He is now head of the firm’s tax practice in Portugal.

He focuses his practice on EU, national and international taxation, M&A, buyouts, corporate restructuring, financial transactions, structuring and transactions. He also has experience in structuring transactions at Centro Internacional de Negócios da Madeira.

Diogo has been recommended by several directories, including Chambers Europe, PLC Which Lawyer?, World Tax and Tax Directors Handbook for his work as tax specialist and with private clients.

JOSÉ ANTONIO POSTIGO-URIBE
Sánchez Devanny
Jose Antonio is the managing partner for Sánchez Devanny’s Mexico City office. He heads the firm’s energy, natural resources and environmental practice group and the firm’s energy task force, a group that includes practitioners of different law practice areas specialising in advising clients of the energy sector. He has advised clients investing in those areas historically open to private participation, especially in gas distribution, developing wind farms, solar projects, cogeneration plants, self-supply schemes, biddings with the CFE (Federal Electricity Commission) and independent producer schemes.

He also advises clients entering the new wholesale electricity market, such as generators, suppliers, traders and final users. José Antonio also advises clients in oil and gas matters, including set up of business in Mexico, structuring investments, bidding processes, processes with PEMEX and gas and other fuel supply and sale. He also represents companies active in the midstream and downstream sector. Following the enactment of the historic 2013 constitutional reform that created an open energy market in Mexico, José Antonio has led the creation of a multidisciplinary industry group within the firm to help clients take advantage of the new opportunities opened up by these reforms.
VENKATESH RAMAN PRASAD

*J Sagar Associates*

Venkatesh is part of the leadership team of JSA in the infrastructure, transportation and energy space.

Venkatesh practises corporate and civil law with a focus on advising/representing clients on domestic and cross border investments, mergers and acquisitions, entry strategies, transaction structuring, joint venture, technology transfer and private equity funding especially in transportation (including railways, MRTS and dedicated freight corridors), energy (including RE, oil and gas value chain and LNG), infrastructure (including construction and engineering), automotive (including HEV and EV) and Make in India-related initiatives. Venkatesh's role in these transactions has included negotiations, drafting, complex structuring, rendering strategic advice and interacting with foreign law firms, investment banks and financial advisers.

He has worked extensively in the energy and infrastructure sector and has the experience of handling a wide array of complex transactions and project documentation. He has advised large Indian and international infrastructure and energy companies (including those in RE, oil and gas, LNG, commodity trading, chemicals and refinery) with regard to their domestic and international investment.

As part of his advisory, Venkatesh advises on the entire gamut of the project value chain risk analysis and provides mitigation strategies.

In the general corporate law and M&A transactions, he has led the team of lawyers representing various large domestic business houses, multinational businesses and state-owned entities on a variety of M&A and joint venture transactions. He has worked extensively in the energy (including the entire hydrocarbon value chain), automotive (including electric vehicles and hybrid electric vehicle), manufacturing and construction and engineering space. His work assignments have related to the entire suite of documents customarily required in these types of transaction and rendering strategic advice to his clients – domestic and foreign.

He has worked on cross-border transactions in multiple jurisdictions, including the US, Europe, the UK, Japan, Latin America, Australia, Africa, ASEAN (including Singapore, Malaysia, Indonesia and Myanmar) and China – along with various foreign law firms, investment banks and strategic management consultants.

Venkatesh has an LLM from New York University (NYU). He is a regular speaker at international and national conferences and workshops on issue of law regulation, investments, and reforms in the infrastructure, energy and automobile space.

FRANSISCUS RODYANTO

*SSEK Legal Consultants*

Fransiscus Rodyanto is a partner at SSEK. He is heavily involved in projects related to oil and gas, mining, the geothermal industry, clean-water supply, ports, real estate and general corporate matters, as well as various commercial transactions. His areas of expertise include project finance, structuring and procurement. Frans’ experience includes advising ExxonMobil on its operations and projects in Indonesia, advising a major multinational oil and gas company on various environmental issues relating to its operations in Indonesia, assisting PT Pertamina and its subsidiaries on various oil and gas matters inside and outside Indonesia and assisting Energy Development Corporation, the largest producer of geothermal energy in the Philippines and the second-largest in the world, with its corporate and financing matters.
in Indonesia. He is advising a Middle East-based petroleum and natural gas company in relation to its joint venture arrangements with an Indonesian oil and gas company related to a US$5 billion oil refinery in Indonesia, and is advising on two petrochemical projects for US and EU companies with a combined investment value of more than US$6 billion. Frans is also involved in an arbitration case under ICC rules with US$400 million in total claims in a dispute over an enhanced oil recovery contract. Frans received his bachelor of laws and bachelor of economics from the University of Indonesia. He earned his master of laws (LLM) in European and international business law from Leiden University in the Netherlands, as part of the Leiden University Excellence Scholarship programme.

MARÍA ELENA SANMARTÍN
Noboa Peña & Torres Abogados

María Elena Sanmartín is an associate at the firm and is involved in a wide range of matters across multiple disciplines, including oil and gas, corporate, labour law and dispute resolution. She has been involved in several tenders with Petroamazonas and the Ministry, as well as day to day advice to clients conducting oil operations in Ecuador. She graduated from Universidad San Francisco de Quito with honours and took US law studies at Loyola University Chicago.

LUIZA SAVCHENKO
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Luiza is a senior international adviser of the banking and finance practice, where she has been involved in several transactions. The main focus of her practice is on international debt and equity capital markets, corporate finance, cross-border M&A and private equity transactions in various industry sectors, including oil and gas, mining, banking, real estate, retail and consumer sectors. Luiza worked at Rosneft Oil Company, as well as at major law firms in London, Washington, DC and Moscow. Luiza is qualified in the state of New York and is a member of the New York Bar Association.

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Christoph Schimmer is a lawyer in the Tax Group at DLA Piper in Vienna, Austria. His main focus lies on international and Austrian corporate tax law. Prior to joining DLA Piper Christoph Schimmer worked as a research and teaching assistant at the Institute for Tax Law at the University of Vienna.

JOÃO SEQUEIRA SENA
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An associate lawyer of Cuatrecasas since 2017, João Sequeira Sena was admitted to the Portuguese Bar Association in 2017.

He is a teaching assistant of the introduction to law course at the Instituto Superior de Economia e Gestão (Lisbon School of Economics and Management), and is also a member of the research team at the Centro de Investigação de Direito Público at Universidade de Lisboa.
João is currently undertaking a master’s in science and honours in legal and political sciences (administrative law) from Universidade de Lisboa; João is preparing a thesis entitled ‘Administrative statement of nullity of administrative contracts’.

CHRISTOPHER B STRONG
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Chris Strong is a partner with Vinson & Elkins’ London office, and has previously been resident in its Middle East, Texas and Asia offices. Chris counsels clients in a wide variety of transactions in the energy, infrastructure and natural resources industries, with a particular focus on project development and finance and mergers and acquisitions. His experience includes transactions relating to upstream oil and gas, power plants, petrochemical facilities, refineries, pipelines, liquefied natural gas, and mining and metals.

PATRICIA TILLER
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Patricia is an experienced commercial projects lawyer advising clients on the full life cycle of energy and infrastructure projects, from acquisition and financing to project development. Patricia focuses her practice on LNG, upstream/midstream energy, power and construction. She advises sponsors, developers, government authorities, major exploration and production companies, independent exploration and production companies, and contractors on innovative and complex projects in the Middle East, Africa, Asia, the Americas and Australia. Patricia has advised on several ‘first-of-a-kind’ projects. She is particularly familiar with market practice in the energy and infrastructure industries throughout the Middle East and Africa, and advises clients on risk management accordingly. She has considerable experience leading negotiations and drafting project agreements in energy-rich countries such as Iraq, the UAE, Kuwait, Egypt, Qatar and Oman. Patricia counsels on both the commercial aspects of a project (structuring and drafting mergers and acquisitions and joint ventures) and transactional contracts (including time charter party agreements, production sharing agreements, joint operating agreements, gas/LNG sales agreements and EPC contracts). Patricia received her bachelor of laws (Honours) from the University of Western Australia.

TANIA ELIZABETH TREJO-GALVEZ
Sánchez Devanny

Among the services that Tania offers within her professional practice should be highlighted the analysis and preparation of different types of contracts relating to the energy sector (electricity and hydrocarbons), as well as legal advice to national and international clients regarding the implementation of the new energy industry regulatory framework in Mexico. Owing to her experience and academic background in the energy sector, she is at the forefront regarding the recently created regulations, which are part of energy reform in Mexico. The aforementioned allows her to inform clients, in a timely manner, on the impact that the regulations will have on their current or future projects. Before joining Sánchez Devanny, Tania was part of a distinguished Mexico City law firm specialising in energy law. In addition, she worked as a lawyer in a state production company developing new Mexican energy industry business and projects.
LOURENÇO VILHENA DE FREITAS
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A partner at Cuatrecasas since 2016, Lourenço Vilhena de Freitas has been a member of the Portuguese Bar Association since 1996. He obtained the highest grade on aggregate (muito bom).

He also advises on infrastructure, energy, public law, litigation and arbitration, and town planning.

A tenured assistant at the Faculdade de Direito of Universidade de Lisboa (Lisbon Law School), where he holds the regency in several subjects and coordinates the Energy Law Project. Lourenço also lectures at Universidade Nova de Lisboa.

He was aid to the Secretary of State for Taxation (XV Constitutional Government – 2002); deputy chief of staff of the State Department of Public Administration (XVI Constitutional Government – 2004); and deputy aid to the President’s Cabinet (XVI Constitutional Government – 2005). A lawyer at the Centre for Taxation Studies (2002), he was also a member of the Administrative Reform Committee in the XVI Constitutional Government.

He advised the Portuguese government on the project of legislative reform of the oil sector concerning production, storage and transportation, and on the contentious-administrative reform in Guinea-Bissau. He also advised on the Portuguese Cultural Heritage Act.

Has published several papers, books and book chapters, namely Direito Administrativo da Energia (Energy Administrative Law). He is a member of the International Law Association, the Portuguese International Law Society and the Portuguese Association of European Law.

Member of the group of experts of UN SCAD (United Nations Security Council Affairs Division), he is also arbitrator at CAAD (Administrative Arbitration Centre), at APMEP (Portuguese Association of Public Procurement) and at CAC (Arbitration Centre of the Portuguese Chamber of Commerce and Industry) and former vice president of the Centre for Arbitration and Litigation at Universidade de Lisboa.

He is a recommended lawyer by several legal directories, namely Chambers Europe and The Legal 500.

GUILLERMO VILLASEÑOR-TADEO
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Guillermo co-heads the Energy Industry Group and member of our tax group based in Mexico city. His expertise relates to corporate tax planning, M&A and transfer pricing legal analyses.

Guillermo has represented and assisted multinational companies in complex cross-border tax litigation resulting from transfer pricing adjustments, cost-sharing arrangements, multinational restructures, and potential recharacterisation of intercompany payments. Guillermo is chair of the Legal and Tax Committee of the Canadian Chamber, and vice chair of the Tax Committee of the American Chamber of Commerce in Mexico. He is a member of the International Fiscal Association, and officer of the International Tax Committee of the American Bar Association, Section of International Law.
KENNETH WALLACE-MÜLLER

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Kenneth Wallace-Müller is a lawyer qualified in England & Wales and an associate in the projects, finance and restructuring group at DLA Piper in Vienna, Austria. His specialisation lies in energy and infrastructure law, including in the upstream, midstream and downstream natural gas markets. Through a secondment as an in-house counsel to a major international gas and power utility, Kenneth gained valuable knowledge of the European gas markets and an understanding of the future challenges for gas market participants.

JIHONG WANG

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Jihong Wang is a senior partner at Zhong Lun Law Firm and an experienced arbitrator of CIETAC. She co-chairs the firm’s construction and infrastructure department, and currently serves as the deputy chair of the ICC China Committee on Environment and Energy, the vice-chair of the IPBA Energy & Natural Resources Committee, a consultant for the Ministry of Ecology and Environment and an expert of HKIAC’s Belt and Road Committee.

As a renowned legal expert in the oil and gas, energy, environmental and urban infrastructure fields, Ms Wang provides services for the investment, M&A, EPC contracting, public–private partnership, financing and acquisitions of, and the resolution of disputes relating to, numerous domestic and foreign energy and resource projects such as oil and gas projects (inclusive of LNG and shale gas), power projects (inclusive of nuclear, hydro, thermal, and wind power) and mining projects (e.g., uranium mining). Ms Wang has extensive experience advising clients in all aspects of Chinese energy transactions and greenfield investment as well as cross-border energy issues on both conventional and renewable resources. For over 15 years, she has worked on many complex energy transaction and infrastructures, including providing legal advice for the international oil and gas giants on their Chinese projects.

OSKAR WINKLER

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Oskar heads the finance, projects and restructuring group in Austria. He advises clients on all aspects of real estate, restructuring law and on all types of restructuring matters, such as security and facility reviews, restructuring of facilities and work-outs, and on mining law matters.

Oskar additionally specialises in insurance law, including insurance supervisory law, general terms and conditions of insurance companies and reinsurance, and he advises insurance companies on M&A transactions and on the administration of assets. Oskar also represents clients in court in all insurance-related disputes.

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Equity partner at Holland & Knight in Bogotá, Mr Zapata has been recognised as one of the lawyers with the highest level of expertise in oil and gas, mining and environmental matters in Colombia. Similarly, he is one of the most recognised lawyers in projects and negotiations in the mining and oil and gas sectors, both ‘upstream’ and ‘downstream’ throughout Latin America. With over 20 years’ experience in natural resources, he has been officer and legal representative of various oil and gas, mining and environmental corporations, as well as serving as president of Columbus Energy Sucursal Colombia, a leading venture company successfully set up in Colombia with 11 blocks in the Llanos and Putumayo basins in Colombia covering nearly 1 million acres, which during 2008 drilled 11 wells resulting in a 91 per cent success rate and the addition of over 2,800bbl/d of net production.

Similarly, Mr Zapata has been legal counsel in the structuring of foreign investment transactions, mergers and acquisitions, as well as reorganisation of corporations in Colombia. Mr Zapata has been member of various boards of directors of multinational corporations in the automotive, energy, telecommunications, industrial and food sectors. He is a professor at the Javeriana, Rosario and Externado de Colombia Universities for environmental, oil and gas, corporate responsibility, environmental liability and sustainable development. Mr Zapata graduated from Universidad Javeriana and holds an LLM from McGill University.

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Dahlia Zamel was born in Cairo, Egypt in 1976. She has a BA from the Arab Academy for Science and Technology and a law degree from Cairo University (LLB, 2009). Dahlia is fluent in both English and Arabic. Practice areas include: corporate and commercial law, oil and gas, mergers and acquisitions, project finance, tax law and labour law. Before joining Amereller Legal Consultants, Dahlia spent four years with the legal department of the International Finance Corporation in Cairo and Istanbul covering both the MENA region and Central Asia. Dahlia has extensive regional experience and is currently based between Cairo, Egypt and Erbil, Iraqi Kurdistan, and covers both central Iraq and the autonomous region of Kurdistan.

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