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# CONTENTS

PREFACE ............................................................................................................................................................ vii
   *Christopher B Strong*

Chapter 1  **ABU DHABI** ........................................................................................................................................ 1
   *James Comyn and Patricia Tiller*

Chapter 2  **ALGERIA** ........................................................................................................................................ 9
   *Samy Laghouati and Djamila Annad*

Chapter 3  **ARGENTINA** ................................................................................................................................ 19
   *Pablo Alliani and Fernando Brunelli*

Chapter 4  **AUSTRIA** ........................................................................................................................................ 34
   *Manfred Fürnkranz, Andreas Gunst, Oskar Winkler, Kenneth Wallace-Müller and Christoph Schimmer*

Chapter 5  **BRAZIL** ......................................................................................................................................... 43
   *Giovani Loss, Felipe Feres and Nilton Mattos*

Chapter 6  **CANADA** ........................................................................................................................................ 54
   *Cameron T Hughes, Curtis Merry and Niki Gill*

Chapter 7  **CHINA** ........................................................................................................................................... 65
   *Jihong Wang, Ying Liu, Anijing Wu, Huiqi Zhao and Guanli Huang*

Chapter 8  **COLOMBIA** ................................................................................................................................... 77
   *José V Zapata Lugo and Claro M Cotes Ricciulli*

Chapter 9  **DEMOCRATIC REPUBLIC OF THE CONGO** ................................................................................. 90
   *Olivier Bustin and Luiza Savchenko*

Chapter 10 **DENMARK** .................................................................................................................................... 99
   *Michael Meyer*
<table>
<thead>
<tr>
<th>Chapter</th>
<th>Country</th>
<th>Authors</th>
<th>Page</th>
</tr>
</thead>
<tbody>
<tr>
<td>11</td>
<td>FRANCE</td>
<td>Yves Lepage and Geoffroy Berthon</td>
<td>112</td>
</tr>
<tr>
<td>12</td>
<td>GERMANY</td>
<td>Matthias Lang and Laura Linde</td>
<td>121</td>
</tr>
<tr>
<td>13</td>
<td>GHANA</td>
<td>Ferdinand Adadzi and Nana Serwah Godson-Amamoo</td>
<td>135</td>
</tr>
<tr>
<td>14</td>
<td>GREENLAND</td>
<td>Michael Meyer</td>
<td>152</td>
</tr>
<tr>
<td>15</td>
<td>INDIA</td>
<td>Venkatesh Raman Prasad</td>
<td>161</td>
</tr>
<tr>
<td>16</td>
<td>IRAQ</td>
<td>Christopher B Strong</td>
<td>176</td>
</tr>
<tr>
<td>17</td>
<td>IRAQI KURDISTAN</td>
<td>Florian Amereller and Dahlia Zamel</td>
<td>187</td>
</tr>
<tr>
<td>18</td>
<td>MEXICO</td>
<td>José Antonio Postigo-Uribe, Guillermo Villaseñor-Tadeo and Tania Elizabeth Trejo-Galvez</td>
<td>202</td>
</tr>
<tr>
<td>19</td>
<td>NEW ZEALAND</td>
<td>Paul Foley</td>
<td>213</td>
</tr>
<tr>
<td>20</td>
<td>NIGERIA</td>
<td>Israel Aye, Laura Alakija and Oghongbemi Aminu</td>
<td>228</td>
</tr>
<tr>
<td>21</td>
<td>NORWAY</td>
<td>Yngve Bustnesli</td>
<td>241</td>
</tr>
<tr>
<td>22</td>
<td>PORTUGAL</td>
<td>André Duarte Figueira, Diogo Ortigão Ramos, Lourenço Vilhena de Freitas and João Sequeira Sena</td>
<td>254</td>
</tr>
<tr>
<td>23</td>
<td>RUSSIA</td>
<td>Natalya Morozova and Rob Patterson</td>
<td>268</td>
</tr>
</tbody>
</table>
## Contents

<table>
<thead>
<tr>
<th>Chapter 24</th>
<th>TRINIDAD AND TOBAGO .................................................................................. 280</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td><em>Jon Paul Mouttet, Lesley-Ann Marsang and Simonne Jaggernauth</em></td>
</tr>
<tr>
<td>Chapter 25</td>
<td>UNITED KINGDOM .......................................................................................... 291</td>
</tr>
<tr>
<td></td>
<td><em>Jason Lovell, Jubilee Easo and Chris Pass</em></td>
</tr>
<tr>
<td>Appendix 1</td>
<td>ABOUT THE AUTHORS.................................................................................... 305</td>
</tr>
<tr>
<td>Appendix 2</td>
<td>CONTRIBUTING LAW FIRMS’ CONTACT DETAILS................................................ 323</td>
</tr>
</tbody>
</table>
2018 has been a transitional period for the international oil and gas industry. With the industry enduring a fourth straight year of low oil prices, and with no prospects for a significant increase in sight, participants in the industry have been forced to adapt. Oil companies must continue to be disciplined, allocating scarce capital only to their best prospects, and shelving less promising projects for future years. Some in the industry have already started to worry that by reducing capital expenditures the seeds of a future price shock are being sown.

Oil-producing countries have been in a similar pinch. Having become accustomed to triple-digit oil prices, the ‘new normal’ of US$50 oil has produced a grim budgetary reality. Producing countries that had only recently tightened fiscal terms in response to high oil prices must now considering loosening them again in order to attract investment. In Saudi Arabia, the world’s largest producer, plans are afoot to sell a minority stake in the company to foreign investors in order to raise cash to diversify the country’s economy, a move that would have been unthinkable a few years ago.

Yet amid the ongoing turbulence there are opportunities. The necessity for existing companies (many of which are over-leveraged and cash strapped) to offload parts of their portfolios will create opportunities for new, leaner competitors to arise. US shale producers, whom many were prepared to write off in the low oil price environment, have made dramatic improvements in efficiency and learned to calibrate their acreage to different oil price environments, focusing on their richest prospects when prices are low and adding lower-value opportunities as prices escalate. Among the major oil exporting countries, low oil prices have provided the impetus for long-needed structural reforms to diversify their economies beyond the extraction of petroleum.

The international oil and gas industry has always been cyclical. Although the last three years have been eventful, they are by no means the first downturn the industry has faced, nor the last. I have no doubt that the years ahead will continue to present challenges and opportunities for practitioners in this most dynamic of industries.

As always, I would like to thank our contributing authors for their outstanding contributions to this year’s edition of *The Oil and Gas Law Review* and also the publishers at Law Business Research for their tireless work in bringing this all together.

Christopher B Strong
Vinson & Elkins LLP
London
October 2018
I INTRODUCTION

In the first six months of 2018, the United Arab Emirates (the UAE) produced an average of 2.86 million barrels of crude oil per day, 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.
These grants mark the acceleration in 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.

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 ADNOC5 and of the former Petroleum Department of the Abu Dhabi government. Accordingly, the SPC has a number of functions:

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.

5 ADNOC was formed pursuant to Abu Dhabi Law No. 7 of 1971 Concerning the Establishment of Abu Dhabi National Oil Company to operate in all areas of the oil and gas industry in Abu Dhabi. The 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.

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.

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;

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;

e 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

f 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.

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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 such company.

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.
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).

### 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.

### 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.

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.

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9  See Article 45 of UAE Federal Law No. 8 of 2017 on Value Added Tax.
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.

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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.
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:

a 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

b through a UAE-incorporated subsidiary, 51 per cent of whose shares must generally be held by one or more UAE nationals.14

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 April 2018 that it is offering six oil and gas concessions in a competitive bidding round with bids due in the fourth quarter of 2018.

Finally, 2018 saw an increased focus by ADNOC on downstream, with the announcement of investments in storage and refining capability outside the UAE and the announcement of plans to build the world’s largest refining and chemicals facility in Ruwais, Abu Dhabi.

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 capital. As noted above, there are a number of exemptions from the UAE Federal Commercial Companies Law, including companies in which a UAE or emirate government-owned entity (such as ADNOC) holds at least 25 per cent of the shares and that operate in oil exploration, drilling, refining, manufacturing, marketing and transmission provided that a provision disapplying the UAE Federal Commercial Companies Law is contained in constitution of the company in question.
Chapter 2

ALGERIA

Samy Laghouati and Djamila Annad

I  INTRODUCTION

By area (2,381,741 km²), Algeria is the largest country in Africa. The distance from the Mediterranean coast to the Hoggar massif is approximately 2,000 km, and it is 1,800 km 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 geo-chemical modelling studies, the size of these fields falls within the 2,650 to 10,500 trillion cubic feet (tcf) bracket.

Algeria’s hydrocarbon basins hold two significant shale gas and shale oil formations, the Silurian Tannezuft 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 Mouydir 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;

1  Samy Laghouati is a partner and Djamila Annad is of counsel at Gide Loyrette Nouel.

2  BP Statistical Review of World Energy review.

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c  condensate: 9.8 million tonnes; and

d  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:

a  the creation of a partnership with Sonatrach;

b  a majority holding by Sonatrach of at least 51 per cent; and

c  the role of operator is devolved to Sonatrach, which 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 (PSC) and the risk service contract (RSC). Law 86-14 was amended in 1991 in order to allow foreign partners to benefit from advantages, such as:

a  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

b  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:

a  the monopoly on oil activities was withdrawn from Sonatrach and entrusted to an institution named ALNAFT, created by the law.

b  the PSC and RSC forms of partnership were cancelled; and

c  oil and gas activities can only be carried out on the basis of an agreement (the Agreement) entered into with ALNAFT, either by Sonatrach on its own, or by Sonatrach with one or more partners national or foreign (the Contracting Party) for exploration or exploitation, or both; 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.

a ALNAFT, which 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

b the Hydrocarbon Regulation Authority, which 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; and
   • 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 this Convention, the Democratic and Popular Republic of Algeria has declared that it will apply the 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 such 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:

a 40 bilateral conventions on the promotion and the protection of investments; and
b 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:

a 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 or exploitation activities, or both, on the basis of an Agreement. The choice of the Contracting 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 programme 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; and

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 structures and facilities, which 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 that 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:

- **a** 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;
- **b** 37 years for conventional hydrocarbons; and
- **c** 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:

- **a** the bank guarantee provided is invalid;
- **b** the minimum research work requirement during the research phase concerned has not been respected;
- **c** failure to implement the development plan on time;
- **d** the obligation to supply the domestic market has not been satisfied; and
- **e** 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 such 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 No. 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 free on board (FOB) price published by one of the specialised 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 specialist 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.

IV PRODUCTION RESTRICTIONS

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 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 (la Taxe superficiare (surface area tax), la Redevance (the royalty) and la Taxe sur le revenu pétrolier (a tax on oil income)), the fourth being l’impôt complémentaire sur le revenu (additional income tax) (ICR), 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 has 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.

\section*{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 awarded, the Contracting Party is obliged to provide a bank guarantee Agreement for the proper performance of the programme of exploration works that 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 Parties 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 restriction

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, and 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, a new hydrocarbon law should be promulgated early next year in order to encourage more significant investments in upstream sector. The exploitation of shale gas and offshore is also becoming a strong priority of the Algerian authorities, and Law 05-07 was amended in 2013 in order to introduce the exploitation of non-conventional hydrocarbons.

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 Khourf field.
We have also witnessed the entry of new players, such as investment funds that 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

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

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.
4 A United States Energy Information Agency’s report issued in April 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
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, where the government has taken actions towards a gradual normalisation of serious economic and financial unbalances inherited from the previous administration, 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 in the past year.

Earlier this year, the United States Federal Reserve’s decisions to increase the interest rate led financial investors to sell bonds issued by emerging countries such as Argentina and caused these countries’ currencies to be devaluated. This affected Argentina more than it affected other emerging economies because of the country’s financial situation, which 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, as will be discussed later on, it is expected that the production of unconventional hydrocarbons will continue to grow until becoming a substantial portion of the national production and, as a result thereof, that the country will be able to regain its hydrocarbons self-sufficiency in the mid-term future.

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 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.

5 This increased Argentina’s country risk factor above 650 points, a 90 per cent increase if compared to mid-2017.

6 When this change in the international scenario occurred, some of the serious macroeconomic unbalances left by the previous administration, basically the fiscal and trade balance deficits, were still far from being fixed and, as the gradual reversion plan implemented by the government progressed, these deficits were being financed by the issuance of large amounts of sovereign debt.
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 Ministry of Energy and Mining (the Ministry of Energy) is the main governmental body involved in energy regulation. The ministry’s secretariat specifically devoted to oil and gas is the Secretariat of Hydrocarbon Resources.

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).
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.\(^7\)

Argentina is a party to 58 bilateral foreign investment protection treaties.\(^8\)

Argentina is a party to 21 double taxation treaties.\(^9\)

### 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.\(^10\)

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 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.\(^11\)

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\(^{7}\) 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.

\(^{8}\) 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.

\(^{9}\) 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.

\(^{10}\) Hydrocarbons Law, Articles 14 and 15.

\(^{11}\) Recently the Ministry of Energy has passed Resolution No. 197/18 with a new set of regulations applicable to surface inspection permits on offshore areas (beyond 20 nautical miles from the coastline). This Resolution provides for a much longer term (eight years) than that applicable to other areas (12 months plus 12 months' extension), and gives the permit holder commercial exploitation rights, whereby the permit holder has the exclusive right to disclose (subject to a few exceptions) and commercialise the data obtained from the inspection activities, on a non-discriminatory basis, until two years after the expiration of the permit. Surface inspection permits currently in force can be converted into permits under this new Resolution, at the permit holder's request.
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.\(^{12}\)

iii  **Exploitation concessions**

Exploitation concessions grant the exclusive right to exploit the existing hydrocarbon fields located in the concession area.\(^ {13}\)

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).\(^ {14}\)

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.

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12 Hydrocarbons Law, Articles 16 to 26.

13 Hydrocarbons Law, Articles 27 to 38.

14 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.
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.

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.

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.

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.

15 Article 33 provides for the obligation of the permit holder to declare commerciality within 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.
16 Article 80 of Hydrocarbons Law.
17 Hydrocarbons Law, Article 81 HL.
18 Royalty is regulated by Articles 59 to 65 of the Hydrocarbons Law and by Decree No. 1,671/1969.
19 Hydrocarbons Law, Article 27 ter (introduced by Law No. 27,007).
20 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.
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.\(^{21}\)

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.\(^{22}\) Owing to the surplus production during the upcoming warm season (October to April), the Ministry of Energy and Mining has announced that exports of natural gas under interruptible supply terms will be authorised during this season, without applying any reimport requirements.\(^{23}\)

Market prices apply for crude oil since the end of 2017 and, as per informal announcements made in the media, the Ministry of Energy does not intend to change this.\(^{24}\)

As regards natural gas prices, the government had understood that it was convenient to guarantee minimum prices in order to foster new investments in unconventional gas projects. In line with this, 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.\(^{25}\)

Pursuant to this scheme, a guaranteed minimum price of US$7.50/MMBtu will apply 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 will be paid to the producers by the federal government.

Recently the Ministry of Energy announced that gas produced from the projects that have already qualified for the programme will continue to enjoy the minimum guaranteed prices until the end of the term, but no applications for new projects will be received.\(^{26}\)

Ministry of Energy Resolutions 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 should converge with import parity prices. As a result of different price schemes, the present average price for natural gas produced in Argentina is approximately US$4.90/MMBtu.

However, the Minister of Energy has announced it intends that by the end of this year all gas prices (except for gas produced from projects that have already qualified for

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21 Hydrocarbons Law, Article 6.
22 Law No. 24,076 and Secretariat of Energy Resolution No. 104/18 (passed on 21 August 2018).
23 Resolution No. 104/18 mentioned in the previous footnote contemplates in addition to this warm season export, 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.
24 In practice producers are being paid slightly less than market prices, around US$67/bbl.
25 The Ministry of Energy Resolution No. 447/17 applied the minimum guaranteed prices programme described above to the production from unconventional reservoirs in the Austral Basin.
Argentina

a subsidised price programme) be subject to market prices. In line with this, Ministry of Energy Resolution No. 46/18, issued recently, provides that gas for power generation shall be acquired through tender processes to be conducted by CAMMESA.27

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.28

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 the holders thereof, nor increase the rate of pre-existent taxes, except for those rates paid in consideration for the performance of services and as contributions for improvements, or a general increase of taxes.29

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27 Company that administers the wholesale electricity market.

28 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.

29 Hydrocarbons Law, Article 56(a).
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 former Secretariat of Energy, which was replaced in 2016 by the Ministry of Energy. The ministry, in turn, has delegated part of its authority on this matter in favour of the Undersecretariat of Hydrocarbons Resources. Other regulations could also be issued by the Ministry 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 such 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 such facilities have to register and inspect such tanks. Companies must also comply with a maintenance plan, report any incidents and report the abandonment of the tanks;

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 pre-eminence. 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.

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.

30 National Constitution, Article 3.
31 Enargas is the national gas regulator.
32 General Companies Law No. 19,550, Article 118.
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.33

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.34 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.35

33 General Companies Law No. 19,550, Article 123.
34 Hydrocarbons Law, Article 71.
35 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 annual basis, in respect of each item or type of activity. This preference must be granted if the economic offer submitted by the Neuquén company is up to 7 per cent greater than the best offer submitted by the other companies, provided that the Neuquén company accepts to reduce its prices to match the best offer received.
Argentina

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.36

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.

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.

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36 Immigration Law No. 25,871, its Regulatory Decree No. 616/2010 and supplementary dispositions enacted by the enforcement authority, the National Immigration Directorate.
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

Unconventional hydrocarbons and, particularly, the Vaca Muerta formation, continue to be at the centre of the industry’s and government’s attention. The continuous process aimed at achieving cost efficiency and improving productivity in Vaca Muerta continues to show significant results. In fact, certain wells reached drilling costs and productivity results that are competitive with those of prolific formations in the United States, which evidences the progress made as operators go through the learning curve in connection with this world-class shale play.37

Since 2010, when the production of unconventional hydrocarbons was insignificant, the volumes produced have been increasing steadily. During the first semester of 2018 the production of unconventional gas increased 36 per cent (shale gas increased 61 per cent; tight gas increased 13 per cent), amounting to 33 per cent of the total national production, while the production of unconventional oil increased 42 per cent, amounting to 12 per cent of the total national production.38

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 2018, the national oil production amounted to 132MMm³/d, 5 per cent more than in of June 2017, while the natural gas production amounted to 485,000 bbl/d, 8 per cent more than that of June 2017.39

37 YPF managed to reduce drilling costs to less than US$7 million per well in Loma Campana (joint venture with Chevron) and La Amarga Chica (joint venture with Petronas). Other operators such as Tecpetrol, Pan American Energy and Total have also made significant progress in this respect.

38 Source: Ministry of Energy.

39 Source: Ministry of Energy.
Among other unconventional hydrocarbons projects that entered the development phase last year it is worth mentioning Fortín de Piedra, where Tecpetrol is executing a US$2.3 billion investment plan. The block already produces 8MMm³/d of gas, 6 per cent of the total national gas production, and is expected to produce 17MMm³/d by mid-2019.

In the shale oil department, Loma Campana (YPF and Chevron) continues to be the largest producer. The block is currently producing 30,200 bbl/d and is expected to produce 100,000 bbl/d by 2024.

The Ministry of Energy has announced that, for the first time in several years, natural gas exports will be authorised, with no obligation to reimport the exported volumes, during the upcoming warm season (October to April).

The financial difficulties the country is going through this year (as explained in Section I) with its impact on pricing and incentives programmes, together with the replacement of the Ministry of Energy, may delay certain investment announcements, considering, also, that general elections are scheduled for October 2019.

However, despite the temporary effects of any financial difficulties, the complete development of the country’s unconventional resources will necessarily continue to be at the top of the government’s agenda (either under this administration or under the administration of another party if eventually Mr Macri were not re-elected in 2018) as this development is strategic and a key aspect in the country’s energy policy for years to come.

Last, it has been announced that by the end of October this year 38 offshore blocks will be offered in a public bidding round to be organised by the Ministry of Energy. The round will include shallow, deep and ultradepth waters blocks in the Austral Marina, Malvinas and Argentina basins in areas of the continental shelf under the jurisdiction of the federal government. The companies submitting the winning bids will be granted exploration permits for a basic term of four years plus four years (three years for shallow waters blocks), plus a five-year extension period (four years for shallow waters blocks). As announced, bids will have to be submitted in February 2019 on a date to be determined by the Ministry of Energy when the call for tenders is issued.

As stated in a series of workshops conducted by the Undersecretariat of Hydrocarbons during the first semester of 2018, originally the call for tenders was to have been launched by the end of July. Then the Undersecretariat made it known by email that the call for tenders would be delayed a few days.

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40 Mr Aranguren was asked to resign to his position as ministry or energy and was replaced by Mr Iguacel, former Director of the National Roads Directorate. Mr Iguacel is a petroleum engineer who had worked in the oil and gas industry years prior to becoming a public servant.

41 As stated in a series of workshops conducted by the Undersecretariat of Hydrocarbons during the first semester of 2018, originally the call for tenders was to have been launched by the end of July. Then the Undersecretariat made it known by email that the call for tenders would be delayed a few days.
Chapter 4

AUSTRIA

Manfred Fürnkranz, Andreas Gunst, Oskar Winkler, Kenneth Wallace-Müller and Christoph Schimmer

I INTRODUCTION

With a land area of 83,879 km² and a population of approximately 8.7 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 325,899 TJ, whereby domestic production was 43,665 TJ and total gas imported amounted to 481,712 TJ. 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 85 per cent of crude oil and natural gas liquids produced, and Rohöl-Aufsuchungs AG (RAG), a privately owned company responsible for approximately 15 per cent of crude oil and natural gas liquids production.

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 5.9 bcm, 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.

1 Manfred Fürnkranz is business partner legal upstream at OMV Aktiengesellschaft. Andreas Gunst and Oskar Winkler are partners, and Kenneth Wallace-Müller and Christoph Schimmer are lawyers at DLA Piper Weiss-Tessbach GmbH.

II LEGAL AND REGULATORY FRAMEWORK

Owing 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 IV 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, 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 Licensing Directive, which aims to ensure non-discriminate access to oil and gas exploration and production, was implemented in Austria under the Federal Procurement Act 2006.6

The Stocks of Crude Oil and Petroleum Products Directive, intended to address the issue of European Union energy security, was implemented by the Oil Stockholding Act 2012, the Energy Steering Act 2012, the Oil Statistics Regulation 2011 and the Gas Statistics Regulation 2012.7,8,9,10

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 most notable being with the Russian Federation regarding the cooperation in the construction of the South Stream gas pipeline project.\textsuperscript{13} Austria has additionally entered into bilateral agreements with both the Czech Republic\textsuperscript{14} and Slovakia\textsuperscript{15} 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 of either an ‘area interest’ for exploration or a ‘field interest’ and ‘production interest’ for production (including the right to acquire the oil or

\textsuperscript{12} Regulation (EU) No. 1227/2011 on wholesale energy market integrity and transparency.
\textsuperscript{13} Federal Law Gazette III No. 39/2011.
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: (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 Austrian Federal and Industrial Participations GmbH (ÖBIT).

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 usage 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 such 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 1997.16

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)\textsuperscript{17} 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 (NRA),\textsuperscript{18} Energie-Control Austria, in short, E-Control.\textsuperscript{19}

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.


\textsuperscript{19} As established by the \textit{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. Such legal entities are considered corporations within the meaning of Section 1 Corporate Income Tax Act 1988,\textsuperscript{20} 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.\textsuperscript{21} 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. Such 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 max 75 per cent of the tax base of the current year.

\textsuperscript{21} German Empire Law Gazette (Deutsches Reichsgesetzblatt) S 219/1897 as amended by Federal Law Gazette I No. 120/2005.
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.\(^\text{22}\) 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 (VAT).

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,\(^\text{23}\) 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 such 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,\(^\text{24}\) 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 500 toe/day per probe or when the production of gas exceeds 500,000m\(^3\)/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 250 toe/day per probe or when the production of gas exceeds 250,000m\(^3\)/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., 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 country 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 States 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

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accordance with Section 59 of the Settlement and Residence Act 2005\textsuperscript{26} 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{27} 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{28}.

Anti-corruption measures are primarily regulated in Sections 302 to 313 of the Austrian Criminal Code,\textsuperscript{29} 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{30} 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 such companies beyond energy suppliers, it is important to implement either of these systems.

Owing 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.

OMV is currently performing a significant seismic survey on an area covering over 600km\textsuperscript{2} in the Weinviertel in Lower Austria, to a depth of between 4,000 to 6,000 metres. In doing so, OMV is increasing its investment in the region by €30 million to approximately €90 million. 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.

\textsuperscript{26} Federal Law Gazette I No. 100/2005 as amended by Federal Law Gazette I No. 70/2015.
\textsuperscript{27} Federal Law Gazette No. 218/1975.
\textsuperscript{29} Federal Law Gazette No. 60/1974.
\textsuperscript{30} Federal Law Gazette I No. 72/2014.
I INTRODUCTION

Twenty years after the opening of the state monopoly over oil and gas activities, the oil industry in Brazil is growing steadily and has matured. Complex deals are becoming more common as the portfolio of exploration and production companies enter into the production phase and service providers start to prepare for the upcoming challenges.

In 2017, Brazilian proven oil reserves decreased 1 per cent in comparison with 2016, representing 12.8 billion barrels of oil. The country is ranked 15th among the world’s biggest proven oil reserves. National oil production reached 2.6 million barrels per day in 2016, and the production of pre-salt totalled 1.3 million barrels of oil equivalent per day, a volume 30 per cent higher than in December 2016. The country is ranked 10th among the world’s biggest oil producers. As regards liquefied natural gas (LNG), production rose 14.5 per cent in comparison with 2016, hitting 40.5 million barrels of oil equivalent per day.

Despite falling oil prices, recent month-by-month statistics show that production is still increasing and pre-salt production rates are improving considerably. During the second half of 2018, the federal government held the 14th concession bid round and the fourth bid round for pre-salt areas.

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 the Brazilian National Oil, Natural Gas and Biofuels Agency (ANP). 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.

i Domestic oil and gas legislation

Pursuant to Articles 20 and 176 of the Brazilian Constitution, oil and gas reserves located on Brazilian territory (including continental shelf, territorial sea and exclusive economic areas) are considered assets of the federal government, and, according to Article 177, the government can contract the exploration and production of deposits of oil, natural gas and other hydrocarbons.

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1 Giovani Loss and Felipe Rodrigues Caldas Feres are partners, and Nilton Mattos is a senior associate, at Mattos Filho, Veiga Filho, Marrey Jr e Quiroga Advogados.
Additionally, Federal Law No. 9,478/1997 (the Petroleum Law), enacted on 6 August 1997, established a new regulatory framework for these activities, especially by establishing:

- the creation of the ANP, and the National Energy Policy Council (CNPE);
- the concession regime, which is the main regime for exploration and production in Brazil;
- the minimum requisites for the tender protocol and concession contracts; and
- the government takes.

Federal Law No. 11,909/2009 (the Gas Law) was enacted to specifically regulate gas activities in Brazil, clarifying the legal background for private investors. The Gas Law gave the Ministry of Mines and Energy the power to decide which pipelines must be built or extended, and established provisions focused on projects related to gas transportation, gas storage and LNG facilities.

Federal Law No. 12,351/2010 (the Pre-Salt Law) established the basic guidelines for exploration and production within pre-salt and strategic areas, which shall be made under the production sharing regime. Additionally, it has established:

- the use of a production sharing agreement (PSA) instead of a concession agreement in such areas;
- Petrobras has a right of preference to be the operator of all exploration and production activities within those areas, with a minimum 30 per cent stake;\(^2\)
- a public company – the recently created Empresa Brasileira de Administração de Petróleo e Gás Natural (PPSA) – as the manager of the PSAs;
- the need for other companies to enter into a consortium with PPSA;
- minimum requirements for the unitisation, according to the ANP’s regulations; and
- government takes for the PSA.

## Regulation

The Ministry of Mines and Energy (MME) is mainly responsible for planning the use of oil and natural gas. The MME proposes to the CNPE, after consulting with the ANP, the definition of the areas that will be subject to concession agreement or PSA regime, and the technical and economic parameters for the PSA. The MME also approves the drafts of the bid documents and PSA prepared by the ANP.

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

The 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 connected activities. The ANP is also responsible for supervising compliance with safety standards and its regulations.

\(^2\) Recently a new law was passed in the Brazilian Congress, changing the wording of the Pre-Salt Law and ending Petrobras’s mandatory minimum stake as well as its mandatory operatorship in the pre-salt area.
The Federal Environmental Protection Agency (IBAMA) is responsible for environmental regulations regarding upstream offshore activities. For onshore activities, other state and local environmental agencies may also be competent to regulate upstream activities.

The Brazilian Maritime Transportation Agency (ANTAQ) is responsible for regulation and supervision of maritime transportation of oil as well as maritime support activities. Only Brazilian navigation companies, duly authorised by the ANTAQ and the 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
With a view to the avoidance of 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. As for tax information exchange agreements (TIEAs), Brazil has enacted Decree 8,003 of 15 May 2013, which put in force a TIEA entered into with the United States.

III LICENSING
From 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.

Therefore, there are two different regulatory frameworks for the granting of exploration and production rights in Brazil, each of them described below. 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 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. In case of a consortium, a qualified operator between 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 from the same corporate group are prevented from making competing offers for the same block. Under the PSA regime, a portion of the production of oil and gas 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’s mandatory operation and minimum stakes in the pre-salt area. Now, Petrobras only has preferential rights for the operation and minimum stakes of each pre-salt area to be offered in a bid round, and for those areas that Petrobras does not exercise its preferential rights, any company may be the operator, provided that such 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 (individually or in a consortium) of the bid will bear 100 per cent of the exploration and production costs, but will receive as payment a share of the profit oil 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, Brazilian reserves, including reserves in the continental shelf, territorial sea and exclusive economic areas, are property of 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 the ANP to perform such activities. The exporting and importing companies must present reports and information to the 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 Secretariat of the Federal Revenue and the state tax secretariats) and the Brazilian Central Bank (currency exchange regulation) will also apply.

Notwithstanding this, in emergency cases in which the domestic supply of oil and natural gas is impaired or threatened (which must be declared by the Brazilian President), the 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 production on which restriction applies will be determined on a monthly basis considering the participation of the company in the national production of oil and natural gas in the month immediately preceding. So far, Brazil has not faced this situation.

There is no specific requirement applicable to the sale of oil into local markets, but 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, the ANP establishes the minimum price for the oil to be considered by the ANP 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, the ANP’s prior authorisation will be required for any assignment of interests. The rationale only applies to direct transfers, as the ANP recently changed its understanding and no longer evaluates indirect transfers (such as mergers).

Only Brazilian companies duly qualified as per the ANP’s requirements for technical, legal and financial qualifications are entitled to receive the title to the 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, neither in the concession regime nor in the PSA regime. The ANP takes on average from four to six months to approve an assignment request.

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

In addition to the 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 before 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 exploration and production of oil and gas 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 transaction.

CADE’s approval is required by the ANP as a condition for the 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 the activities of research, or exploration and production of oil and gas 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 good 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 good from the country) and subsequent importation under the temporary admission regime in (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 manufacturing 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).

At the state level, VAT (value added tax) benefits may also be available depending on the legislation of each state. Agreement No. 130/07 has authorised Brazilian states to establish a tax reduction on the import of certain REPETRO-eligible goods related to the oil production phase, such that the total tax burden applicable to such transactions corresponds to 3 per cent or to 7.5 per cent, depending on whether the importer intends to register VAT credits or not.
The Agreement has also authorised Brazilian states to exempt or grant a tax reduction so that the total tax burden corresponds to 1.5 per cent on the import of equipment related to the oil exploration phase. There may be other specific benefits available related to goods utilised concomitantly during both the exploration and production phase, related to the drawback regime, among others.

In 2005, Law No. 11,196 was issued establishing tax benefits for the oil and gas industry, among others. The benefits include exemption of corporate taxes (IRPJ, CSLL) and IPI. However, Law No. 11,196 also requires that the company meets 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 damages caused to the environment, which has a strict liability nature (i.e., irrespective of fault). The sole demonstration of the cause-effect relationship between damage caused and 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 such liability. The National Environmental Policy further expanded the list of parties that may be liable for environmental damages, and set joint and several liabilities among 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, which concurs with 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 concurs with certain behaviours deemed to be damaging to the environment will also be subject to criminal penalties. In the administrative sphere, the 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 governmental financial entities.

IBAMA or the competent state environmental agency, in addition to supervising compliance with environmental matters, issues the necessary environmental licences. As a general 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 the presentation of environmental assessments, such as the environmental impact assessment and an environmental impact assessment report by the company, 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. The exploration and production of oil and gas and extended well tests also requires the following licences issued by IBAMA and the presentation of the correspondent environmental assessment:

- **Preliminary licence**: granted during the preliminary stage of planning the operations and activities and approves its location and conception, it attests to the environmental feasibility and sets forth the basic and conditioning requirements to be met during the subsequent stages of its implementation;

- **Installation licence**: authorises the setting up of the operations or the activity according to specifications in the approved plans, programmes and designs, including measures of environmental control and conditions, of which they are determining factors; and

- **Operating licence**: authorises the operation, after effective compliance with the previous licences and with the environmental control measures and conditions determined for the operation have been checked.

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 the ANP. The ANP may require financial guarantees to be presented during the term of the agreement to cover such 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 from 30 to 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 accomplished, the ANP may impose a penalty of 60 per cent over the amount not complied with, in case the percentage of local content not complied with is less than 65 per cent. If the amount not complied with is more than 65 per cent, the penalty may vary from between 60 and 100 per cent of the amount not complied with. In 2013, the ANP published rules and criteria for the procedure of local content certification.

For the 14th bidding round and third PSC bidding round, the 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, 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 working visa and fulfil all of the requirements established by the Brazilian National Immigration Council. In this sense, 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 position of manager in a Brazilian company (officer), and is usually granted for the maximum duration of five years; and (2) a temporary visa: granted to foreign nationals coming to Brazil for short periods of time with 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 actually 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 it regulates civil and administrative liability of companies for the performance of corrupt acts against the government. Such law establishes a straightforward criterion to input responsibility on legal entities, whether national or foreign, for any act of corruption harmful to the government. Parent companies, subsidiaries, affiliates and consortia will be jointly and severally liable for the performance of corrupt acts.

The sanctions include the publication of the conviction and a fine that can reach 20 per cent of gross sales of the financial year preceding the initiation of administrative proceedings. If it is impossible to apply such criterion, the fine shall vary between 6 million and 60 million reais. Such 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
After a long period of hardship caused by the international landscape and the instability of Petrobras, the Brazilian oil and gas sector has undergone major changes throughout the past year and a half. Important regulatory and legislative developments are taking place in the
country aiming at maintaining the momentum of growth in production rates and direct government incomes. The unprecedented success of the latest bid round proved Brazil’s strength in attracting investment from the largest players in the industry.

Now, as the exploration and production projects become increasingly complex and capital-intensive, mainly in the pre-salt areas, the current challenge for the government is to modernise regulation and live up to a fast-maturing market environment in order to consolidate Brazil’s position as a continental leader in the energy commodities business.

On the regulatory front, the CNPE and the ANP announced the intention to establish a regular schedule of bidding rounds for oil and gas exploration and production rights. In addition to the four bidding rounds conducted in 2018, among which the 15th concession bid round and the fifth pre-salt bid round, the government plans to conduct another five bids in 2019:

- the sixth pre-salt bid round;
- the 16th, 17th and 18th concession bid rounds; and
- the fifth bid round for small fields.

The federal government considered the 15th bidding round a success. Even though only approximately 30 per cent of the total blocks offered were awarded (22 out of 88), the 15th bidding round had the largest total signature bonus in history for a concession round: over 8 billion reais. It also had the largest signature bonus offer for a block, at 2.82 billion reais for block C-M-789. This block – among other granted record-breaking areas – is located just outside the pre-salt polygon, highlighting the potential of this area.

The pre-salt bidding rounds were also successful, with Exxon, Qatar Petroleum and BP making their way into Brazilian pre-salt areas. Almost all major IOCs presented bids in the second and third bidding rounds, leading to aggressive offers of profit oil share for the government. The competition was more intense for the areas of Uirapuru and Dois Irmãos. The federal government plans to receive at least 24 billion Brazilian reais until 2020 bidding rounds, and the possible discovery of commercial petroleum resources will increase government participation and Brazil’s energy security.

One of the most relevant changes occurred in the pre-salt: the federal government revoked the mandatory operatorship of Petrobras in consortiums under the production sharing regime. This is a major opportunity for the global industry in upcoming bid rounds. This legislative trend is especially noteworthy in light the undergoing discussions in the National Congress to open up the onerous assignment regime to investments from other companies.

The federal government is also reviewing the deadlines established for the exploration phase of the blocks granted on the 11th and 12th bid rounds, given the difficulties faced by concessionaires in obtaining environmental licences for such blocks, and the current challenging oil prices. In addition, as discussed above, the federal government has recently extended the REPETRO regime for 20 additional years (i.e., until 2040).

In addition, the MME has loosened local content percentages and penalties. Local content requirements have long been a topic of discussions between the government, E&P companies and suppliers. In fact, disputes between suppliers and E&P companies related to local content have been challenged in courts as opposed to being resolved administratively, as was the case in the past. These changes, reducing the percentage of local content requirement, seek to provide more legal certainty to investment, increasing interest in future bidding rounds, especially in view of the regional competition for investment with Mexico.
Another regulatory development expected shortly is the enactment of a regulation by the ANP that will facilitate upstream financing, and finally acknowledging and allowing the implementation in the country of widely used funding methods in international practice, such as reserve based lending.

In addition, Petrobras’ divestment programme, intended to reduce the indebtedness of the company and generate value for its shareholders, has been receiving important accreditation from public authorities, and the initial resistance presented to the programme by several sectors of the government is now significantly diluted. A recent important development in this regard was a decision of the Brazilian Federal Accounts Board (TCU) that favoured Petrobras’ strategic partnerships with private companies to facilitate the sale of assets. The goal of partnerships and divestments within the strategic plan is to amount US$21 billion until 2019.

The TCU also recently brought up a discussion on pre-salt unitisations by ordering the removal of two blocks from the 15th concession round and possibly from one of the areas to be offered in the fourth pre-salt contract bid round. These discussions focus primarily on the effectiveness of the dual-granting regime currently in force in Brazil for E&P activities, and although incipient, may lead to greater legislative discussions on the issue.
I INTRODUCTION

Canada is endowed with significant oil and natural gas resources, and is globally ranked third in crude oil reserves (proven 168.9 billion barrels) and eighteenth in natural gas reserves (1.9 trillion cubic metres). Today, Canada is a leading producer and exporter, ranking as the world’s fourth-largest producer of natural gas and fifth-largest for oil. Canadians are among the most skilled people in the world at extracting, processing and transporting conventional and unconventional hydrocarbons, using the world’s most advanced technology.

The Canadian oil and gas industry got its start in the 1850s in Enniskillen Township in the province of Ontario where early entrepreneurs exploited the oil springs and asphalt beds visible on the surface of swampy ‘gum beds’. That oil was produced, transported, refined and sold as lamp oil and other products. With the adoption of innovations like the cable-tool drilling rig, which allowed drillers to access vast quantities of crude oil, the oil boom took hold in the United States and spawned a burst of activity in Southwestern Ontario in the late 19th century. While the oil potential of Ontario was limited, drillers gained valuable knowledge – knowledge they took with them to the prolific oil and gas fields of Western Canada and offshore Eastern Canada.

The dawning of the oil and natural gas industry in Western Canada began accidentally in 1866. Drilling for water near Medicine Hat, Alberta, a Canadian Pacific Railway crew encountered natural gas. Additional wells were drilled and more gas was discovered. Further natural gas discoveries were made in southern Alberta in the early 1900s. Thereafter pipeline construction began in order to move gas to larger population centres.

Oil was discovered in significant quantities in 1914 at Turner Valley, Alberta; in 1920, at Norman Wells in the North West Territories; and at Wainwright, Alberta in 1923. Not until 13 February 1947, however, did Canada emerge as an oil-rich nation. After 133 unsuccessful wells and years of frustration, Imperial Oil struck a prolific oil reservoir with its Leduc No. 1 Well. This was the turning point in Canada’s oil history and led to a number of significant exploration successes in both oil and natural gas from the 1950s to the 1970s. These developments in the Western Canadian sedimentary basin brought substantial economic growth not just to Alberta but across Canada.

On the back of geoscience, engineering and technology (and a lot of trial and error), the industry matured. Geophysics became a critically important aspect of improving success

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1 Cameron T. Hughes is a partner and Curtis Merry and Niki Gill are associates at McCarthy Tétrault LLP.
3 ibid.
rates, finding new pools and exploiting complicated geological structures. During the latter decades of the 20th century, the industry turned its attention to exploring the frontier areas of Northern Canada and offshore the west and east coasts, successfully drilling wells in the McKenzie Delta in the north and offshore the Maritime provinces. While the great potential of Alberta's oil sands was well known, it was not until the latter part of the century that modern attempts at mining took hold with modest commercial production beginning in the late 1960s. Concurrent with improved oil sands production economics, a number of federal and provincial changes to the tax and royalty regimes spurred significant development and investment in the 1990s and the first decade of the 2000s. With it came international recognition of the oil sands as one of the largest oil resources in the world.

The current decade has seen the emergence of shale and tight sands hydrocarbon opportunities in North America on a commercial scale, including Canada’s Montney and Duvernay plays. The magnitude of these plays has had a dramatic impact on crude oil prices, regional natural gas prices and supply and demand trends. As domestic production in the United States displaces traditional suppliers of oil and natural gas to its economy, the immediate future has Canada and other producing countries in a race to find new markets around the world.

II LEGAL AND REGULATORY FRAMEWORK

Canada is a constitutional monarchy with a parliamentary democracy system of government. Power is divided between the federal government and the governments of the 10 provinces and three territories. Most of Canada’s private legal system (contracts, transactions, etc.) is based on the English common law and legal precedents. In the province of Quebec, a Civil Code governs such matters. The provinces have jurisdiction over local matters including the exploitation of natural resources, including oil and gas, while the federal government is responsible for national and international matters, such as pipelines that cross provincial and international borders and the import and export of energy commodities.

i Domestic oil and gas legislation

The Constitution Act provides the federal and provincial governments with exclusive legislative control over an enumerated list of subjects. The power to regulate natural resources for example, generally falls under provincial jurisdiction, whereas the regulation of interprovincial or international pipelines and aboriginal affairs falls to the federal government. Legislative authority over environmental matters, however, is not expressly allocated to either government and is an area of shared responsibility.

ii Regulation

The National Energy Board (NEB) is the primary federal energy regulator and is governed by the National Energy Board Act. The NEB is responsible for, among other things, regulating: (1) pipelines that cross international or provincial boundaries; (2) energy imports and exports; and (3) offshore energy activities. The federal government is also responsible for regulating certain environmental activities under the Canadian Environmental Assessment Act, as well as aboriginal interests and the issuance of leases in respect of aboriginal rights through the Indian Act and the Indian Oil and Gas Act.
With regard to provincial regulation of natural resources in the western provinces, set forth below are the main regulatory bodies responsible for administering and overseeing oil and gas production and environmental regulation, as well as the primary legislation applicable thereto.

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<th>Province</th>
<th>Regulator</th>
<th>Primary Legislation</th>
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<td>British Columbia</td>
<td>Oil and Gas Commission</td>
<td>Oil and Gas Activities Act</td>
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<td>Environmental Assessment Office</td>
<td>Petroleum and Natural Gas Act</td>
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<td>Environmental Assessment Act</td>
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<tr>
<td>Alberta</td>
<td>Ministry of Energy</td>
<td>Mines and Minerals Act</td>
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<td>Alberta Energy Regulator</td>
<td>Oil and Gas Conservation Act</td>
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<td>Oil Sands Conservation Act</td>
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<td>Environmental Protection and Enhancement Act</td>
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<td>Saskatchewan</td>
<td>Ministry of the Economy</td>
<td>Oil and Gas Conservation Act</td>
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<td>Environmental Management and Protection Act</td>
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<td>Manitoba</td>
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<td>Oil and Gas Act</td>
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<td>and Mines of Manitoba (Petroleum Branch)</td>
<td>Oil and Gas Production Tax Act</td>
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<td>Surface Rights Act</td>
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With regard to provincial regulation of natural resources on the east coast, offshore oil and gas activities in the Atlantic are jointly regulated by the federal government and the provincial governments of Nova Scotia and Newfoundland through the Offshore Petroleum Boards. Activities in northern Canada (Northwest Territories and Nunavut) are under the authority of the NEB, the federal Departments of Fisheries and Natural Resources, and the Department of Aboriginal Affairs and Northern Development.

iii Treaties

Canada is a member or signatory to several major trade and investment protection agreements, including the World Trade Organization, the North American Free Trade Agreement (NAFTA), the Canada-European Union Comprehensive Economic and Trade Agreement (CETA) and the Trans-Pacific Partnership. Several of these agreements may be subject to significant change in the near future, in particular, NAFTA, which is being renegotiated between Canada, the United States and Mexico. CETA was finalised in February 2016 and approved by the European Parliament in February 2017. The Canadian bill to implement CETA received royal assent in May 2017, came into force provisionally on 21 September 2017 and will come into force fully and definitively upon ratification by all EU Member States.

Canada has bilateral free trade agreements with the following countries: Chile, Colombia, Costa Rica, Honduras, Israel, Jordan, Panama, Peru, South Korea and the European Free Trade Association (Iceland, Liechtenstein, Norway and Switzerland).

All Canadian jurisdictions have implemented legislation permitting the enforcement of international arbitration awards domestically. Moreover, each province and territory has enacted its own legislation that generally adopts the UNCITRAL model law and the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention). Owing to Canada’s federal system, provinces have primary jurisdiction over arbitration and enforcement of awards. However, arbitration concerning matters of federal jurisdiction and involving the federal government, a departmental corporation or a crown corporation as a party are subject to the federal Commercial Arbitration Act.
Canada has also ratified the World Bank Group’s Convention on the Settlement of Investment Disputes between States and Nationals of other States (ICSID). The ICSID provides a neutral forum and framework for foreign investors and the Canadian government to arbitrate disputes brought under investment treaties.

III LICENSING

i Ownership of mineral rights
In order to produce oil and gas in Canada, a party must own the rights to the minerals or be in possession of a lease obtained from the mineral rights owner. Generally, mineral rights in Canada can be owned in one of three ways: (1) by the provincial and federal governments (Crown rights); (2) by First Nations groups (Aboriginal rights); or (3) by individuals or corporations (freehold rights). The owner of freehold rights is said to hold a fee simple interest; the closest to absolute ownership of a mineral interest that an individual or company can obtain in Canada. Accordingly, the freehold owner may sell, lease or encumber the mineral interest as it sees fit, subject only to restrictions applied by the government for the greater good of the municipality, province or country.

ii Ownership of surface rights
The property rights to minerals and to the surface of the land under which minerals are situated are separate, and therefore, obtaining a right to extract minerals does not grant a right to occupy the land. In order to occupy the lands to conduct exploration and production activities, a party must either own the surface rights or have obtained a surface lease from the surface rights owner (which owner is not necessarily the same as the mineral rights owner). Surface leases for Crown rights can be obtained from the applicable provincial regulator or department. Surface leases for freehold lands can be obtained through negotiation with the landowner. If, however, negotiations with a landowner are unsuccessful, an order can be obtained from the provincial regulator to force the surface rights owner to provide access to the lands.

iii Acquiring freehold rights
To extract minerals from freehold lands, a party must own the freehold rights or obtain a lease from the freehold owner. Freehold leases acquired from the freehold owner through negotiation create a contractual relationship between the owner in possession of the mineral rights (the lessor) and the party contracting to exploit those rights (the lessee). In general, a freehold lease grants a lessee the rights to extract minerals in exchange for a royalty on the produced substances. A freehold lease has two terms: the primary term and the extended term. Subject to certain exceptions, a lease will survive and continue past the primary term and into the extended term only if production has been obtained. During the extended term, a lease will typically terminate if production or production operations on the lands cease.

iv Acquiring Crown rights
To extract minerals from Crown lands, a party must obtain a lease or licence from the provincial government through an auction process, or acquire an existing lease. Auctions are generally held at regular intervals with the location of the offered interests being requested by a prospective lessee or selected by the ministry in charge of the auction. Typically, a sales
notice will be issued by the province and a lease or licence awarded to the highest bidder. Short-term licences are granted for a defined term for exploratory operations, whereas leases with indefinite terms are granted for production operations. Typically, licences are initially issued and converted into leases if production is obtained. If a licence is not converted into a lease, or if production stops during the term of a lease, the mineral rights revert to the Crown.

IV PRODUCTION RESTRICTIONS

Although there are restrictions regarding the type or extent of oil and gas activities that can be undertaken, generally there are no explicit statutory or common law restrictions on production in Canada. Restrictions on activities, such as the use of spacing units to limit the number of wells within a specific geographic area, are aimed at ensuring the orderly and efficient development of oil and gas rights.

Potential exporters of oil and gas are required to obtain export licences from the NEB. When reviewing an application for an export licence, the NEB will consider foreseeable energy requirements in Canada.

V ASSIGNMENTS OF INTERESTS

Subject to certain restrictions on fractional ownership, interests in freehold minerals can be transferred in accordance with the applicable provincial legislation. Interests in Crown licences or leases can also be assigned, in whole or in part, to a registered corporation or an individual over the age of 18. The forms to be submitted and associated fees required to effect both types of transfers vary by province.

VI TAX

i The Income Tax Act and taxable income

Corporate income taxes are imposed at the federal and provincial or territorial level. Federal income tax is levied on the worldwide income of every Canadian resident, subject to applicable income tax conventions. There are three categories of income that residents and non-residents are taxed on: business, employment and capital gains on disposition of certain types of Canadian property. The combined federal and provincial income tax rate imposed on corporations varies depending on the nature, size and location of the business as well as other factors. Tax credits and other incentives are available to reduce effective tax rates. Non-residents that earn passive income in Canada (such as dividends and royalty fees) are subject to a 25 per cent withholding tax.

ii Branch v. subsidiary

A subsidiary is a corporation that is resident in Canada and subject to Canadian federal and provincial taxation. Conducting Canadian operations as a subsidiary carries a number of consequences. For example, transactions between related companies, even the parent, must be effected at fair market value for tax purposes. A benefit of conducting Canadian operations as a subsidiary is that the parent is shielded from most Canadian liabilities because the parent and subsidiary are considered distinct legal entities.

A branch is a business carried on by a non-resident corporation in Canada. A non-resident corporation must pay Canadian tax on income earned in Canada. However, Canadian tax
treaties typically limit tax to income attributable to a permanent establishment in Canada (i.e., a fixed place of a business). A branch is typically subject to a branch tax of 5 per cent to 15 per cent. If the non-resident corporation pays taxes on its Canadian source income, the home jurisdiction typically offers tax credits for taxes paid in Canada. Branches are considered to be an efficient way to initiate operations in Canada because start-up losses may be deductible against the non-resident corporation’s taxable home income. Once profitable, the branch may be transferred into an incorporated subsidiary without adverse Canadian tax consequences.

iii Resource pools

Canadian tax law provides certain incentives to deduct the cost of exploration, acquisitions and development of oil and gas reserves. Resource tax pools provide expedited deduction rates compared to deduction rates available for the depreciation of other capital property. The costs associated with exploration are deductible at a rate of 100 per cent per tax year. Development expenses are deductible at a rate of 30 per cent. Property expenses, including acquisition costs, are deductible at 10 per cent per year. Any unused deductions may be rolled-over into future tax years.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Legislation

The federal and provincial governments work together to regulate the environment through the implementation of legislation pertaining to the release of hazardous substances, the granting of emissions licences, the protection of fish and wildlife, and the remediation of contaminated sites. These acts and regulations also often contain provisions relating to offences such as the failure to obtain licences or permits, or unlawfully discharging pollutants, which offences can result in fines and potentially, although rarely, jail time.

ii Environmental assessments

An environmental assessment and a related approval is often required in advance of a project breaking ground and is generally a precondition to the issuance of ancillary licences and permits from the federal and provincial governments.

The main federal environmental legislation, the Canadian Environmental Assessment Act, regulates interference with fish, species at risk and migratory birds and provides the framework for the federal environmental assessment process as administered by the Canadian Environmental Assessment Agency. In addition, certain provincial environmental acts provide a separate environmental assessment framework; for example, the Environmental Assessment Act in British Columbia and the Environmental Protection and Enhancement Act in Alberta. Although shortened timelines can be expected for smaller projects, an assessment for a large project can take 24 to 36 months and often involve court-like hearings. Once a project has received substantive environmental approval the issuance of related and incidental permits generally follows relatively quickly.

A single project can trigger both federal and provincial environmental assessments. In order to manage this overlap, and to clarify the roles of the regulatory agencies involved, many provincial governments have entered into agreements with the federal government pertaining to joint environmental review processes. Where such is the case, the agencies work together to conduct a coordinated assessment, with one agency acting as the lead for the project.
iii Carbon taxes
The federal government intends to implement a national carbon tax to come into force in January 2019, setting a minimum surcharge on carbon-based fuels, in an effort to meet international commitments for the reduction of greenhouse gases. If implemented, the federal programme will impose a carbon tax on provinces without provincial carbon pricing programmes currently in force. The federal programme will be modelled after Alberta’s Climate Leadership Act, which applies a carbon levy effective as of 1 January 2017 throughout the fuel supply chain, including at the point of purchase and import.

iv First Nations consultation and accommodation
Consultation with aboriginal groups is required for projects that may impact aboriginal rights and interests. While the duty to consult rests with the provincial and federal governments, many procedural aspects of this obligation can be delegated to the project proponents. The duty to consult does not strictly require a proponent to obtain consent from the affected aboriginal group. Rather, it requires a commitment to a meaningful process of consultation carried out in good faith. The scope of the duty is assessed on a case-by-case basis. There is no stand-alone duty to accommodate aboriginal groups. However, good faith consultation may reveal a duty on the Crown to accommodate aboriginal rights or interests. Both federal legislation and the common law with regard to First Nations consultation are evolving rapidly, and should be carefully considered for all oil and gas projects in Canada.

v Personal liability
Under provincial environmental legislation, corporate directors and officers may be held personally liable for the restoration of contaminated sites, particularly where they had managerial control over the pollutants or made decisions that resulted in contamination. Moreover, and in addition to certain fiduciary duties and standard of care requirements, provincial environmental legislation typically deems directors liable for corporate offences that they authorised or directed.

vi Decommissioning
When oil and gas activities on a parcel of land end, the party holding the well licence is responsible for decommissioning and remediating the site. British Columbia, Alberta and Saskatchewan have all instituted Licensee Liability Rating (LLR) programmes to reduce the occurrence of ‘orphaned’ properties where the responsible party is financially unable to fund remediation. The LLR programmes calculate the deemed asset to liability ratio of each business with a well licence in the province. Depending on the resulting ratio, the provincial regulator may require security deposits to be paid to offset the possibility that a party will be unable to fund future remediation obligations. As concerns over orphan wells grow owing to the increased number of bankruptcy events affecting oil and gas producers in Canada, regulators have sought new ways to ensure reclamation costs are not borne by taxpayers. In particular, the Alberta Energy Regulator now requires buyers of oil and gas assets to achieve a post-transfer LLR of 2.0 (as opposed to the standard 1.0 requirement imposed on the sellers of the assets) or pay a security deposit in order for well and facility licenses applicable to the purchased assets to be transferred to the new owner. This requirement, although temporary, resulted in widespread uncertainty in the industry and buyers and sellers alike remain wary of changes to LLR programmes by provincial regulators.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

A business acquisition can generally be structured as either a purchase of shares or assets. Acquiring assets is often preferable to a buyer because the buyer only pays for the specific property it wants and does not acquire liabilities of the seller, such as pension obligations, debts or judgments. However, acquiring assets has downsides as well, for example, buyers do not receive the benefit of retained losses that may be deductible against future taxable income. In a share transaction, the buyer acquires and is exposed to both disclosed and undisclosed assets, rights and liabilities of the corporation such as employment contracts, accounts and tax obligations.

A corporation is the entity most often used to carry on business in Canada. A corporation is a legal entity separate from its owners. As a result, the property, rights and liabilities are those of the corporation, not the shareholders. Corporations may be created under both federal or provincial statutes. If the corporation's business will be in a sector of federal jurisdiction (e.g., banking), it must be formed under the federal statute.

United States businesses coming to Canada often use unlimited liability companies (ULCs) as a vehicle for their business activity in Canada to take advantage of favourable treatment afforded to ULCs as flow-through entities under United States tax law.

Unlike a corporation, a partnership is not a separate legal entity from its owners. It is a business organisation comprised of individuals or business entities that share in profit, losses and liabilities. Partnerships are often used to flow through losses to its partners to deduct against the partners income. A partner's exposure to liability may be minimised by forming a limited partnership, rather than a general partnership. In a limited partnership, a partner's liability is limited to the extent of its investment in the partnership, as long as it takes a passive role in the business and management of the partnership.

ii Capital, labour and content restrictions

Non-Canadian residents or citizens carrying on business-related activities for compensation in Canada generally require a work permit. There are, however, a number of exemptions to the work permit requirements. For example, multinationals can temporarily transfer management or executives for training to their Canadian locations. If Canadian employers are unable to fill positions with qualified Canadian citizens or residents, they may apply under the Temporary Foreign Worker Program (TFWP). However, the federal government implemented changes to the TFWP in 2014, making it more costly and difficult to hire foreign workers.

iii Foreign ownership of land

Pursuant to the federal Citizenship Act, non-residents may purchase, hold and dispose of real property in Canada as though they are residents of Canada. However, provinces have the right to restrict the acquisition of land by non-resident individuals as well as by corporations and associations controlled by non-residents. For example, in Alberta, the Agricultural and Recreational Land Ownership Act and the Foreign Ownership of Land Regulations restrict non-Canadians from buying significant amounts of agricultural and recreational lands. A withholding tax is also applied to the sale of Canadian land by a non-Canadian, unless the land is considered to be protected property under a treaty between Canada and the seller's resident country.
iv Investment Canada Act

The Investment Canada Act (ICA) is the only federal foreign-investment law of general application. Whether a foreign investor establishes a Canadian operation through an acquisition or by starting a new Canadian business, the investment may be subject to notification, filing, review and approval requirements under the ICA.

Investments to form a new Canadian business and acquisitions of control of existing businesses that do not exceed applicable thresholds are subject to notification requirements, namely the filing of an information form before or shortly after closing of the transaction. Investments that exceed applicable thresholds are subject to review, which requires the filing of more detailed information concerning the target business and the investor’s intentions. In general, the review process takes 45 days and focuses on whether the proposed transaction ‘is likely to be of net benefit to Canada’.

Where a proposed acquirer of a Canadian business is an enterprise controlled directly or indirectly by a foreign government, certain guidelines are applied. The guidelines reflect concerns regarding the ‘governance and commercial orientation’ of state-owned enterprises. The guidelines permit the Minister to examine whether the corporate governance and reporting structure of the enterprise adhere to Canadian principles of corporate governance such as transparency, independence of the board of directors and independent audit committees. Although state-owned enterprises have been afforded control of Canadian oil and gas businesses in the past, in 2012 changes to Canada’s policy for reviewing investments by state-owned enterprises were implemented. In particular, it was announced that the acquisition of control of a Canadian oil sands business by a foreign state-owned enterprise will be found to be of net benefit only in exceptional circumstances.

v Competition Act

The federal Competition Act contains non-criminal or administrative provisions that allow the Competition Tribunal to review certain business practices and issue orders to prevent anticompetitive practices in the marketplace. In general, if a proposed transaction exceeds the thresholds set forth in the Competition Act regarding the size of the parties (assets or sales exceeding C$400 million) or the size of the proposed transaction (exceeding C$92 million), the parties are required to notify the commissioner, supply information and obtain approval, prior to the completion of the transaction. In certain circumstances, the parties may be able to obtain an advanced ruling certificate, such as where the transaction raises minimal substantive law issues.

vi Anti-corruption

Domestic corruption

The Criminal Code of Canada (the Code) creates an offence for bribing private and government officials. The provisions capture all aspects of corruption, including the solicitation, offer, payment and receipt of a bribe. Consequently, both the payer and the official receiving the bribe can be prosecuted. Corporations may also be held responsible for offences under the Code, including corruption offences.

At common law, a corporation can be held criminally liable if the criminal act or omission was committed by an individual determined to be the ‘directing mind and will’ of
the corporation.\(^4\) However, the Code creates statutory criminal liability for ‘organisations’. Broadly speaking, an organisation may be found to be a party to an offence if a senior officer acting within his or her authority, with the intent to at least partially benefit the corporation, is a party to an offence. An organisation may also be liable if a senior officer directs a representative of the organisation to be a party to an offence or knowingly does not take all reasonable measures to prevent a representative of the organisation from being a party to an offence.

**Foreign corruption**

According to the federal Corruption of Foreign Public Officials Act (CFPOA), it is a criminal offence for any person to offer or pay a bribe to a foreign public official. The CFPOA prohibits Canadians from directly or indirectly offering, agreeing to give or giving a loan, reward, advantage or benefit of any kind to a foreign public official in order to obtain or retain an advantage in the course of business. In recent years, the Royal Canadian Mounted Police and the Crown have vigorously enforced the CFPOA. Although the CFPOA does not create an offence for foreign officials who receive bribes, the Code has been used to prosecute foreign officials who receive bribes while in Canada.

**IX CURRENT DEVELOPMENTS**

Over the past few years, the oil and gas industry in Canada has been in a period of upheaval due to the significant drop in the price of oil that first began in 2014. Although low oil and gas prices continued to wreak havoc on the revenues of Canadian oil and gas producers, and oil and gas prices are expected to remain volatile for the foreseeable future, there are signs that the industry is beginning to adapt to the new energy climate in Canada. In particular, by driving down costs and consolidating core assets, senior and integrated producers have made headway in the struggle to once again become profitable, and we may see junior or intermediate producers making a comeback in Canada as commodity prices stabilise and improve.

In 2017, deal activity in the Canadian oil patch has been driven in large part by an exodus of international players from the oil sands, while Canadian producers have expanded their position in those assets. In particular, domestic companies like Cenovus Energy Inc and Canadian Natural Resources Limited, which have proven to be profitable amid the price drop, have greatly increased their exposure to the Canadian oil sands market through blockbuster deals involving the purchase of oil sands assets from ConocoPhillips and Shell Canada Limited, respectively.

2017 also brought about significant developments in respect of the approval and construction of various pipeline projects across the country. While in late 2016, the federal government approved the Kinder Morgan Trans Mountain pipeline (which runs from Edmonton, Alberta to Burnaby, British Columbia) and Enbridge’s Line 3 replacement pipeline (which runs from Hardisty, Alberta to Wisconsin in the United States), many pipeline projects, including the Trans Mountain project, have been hindered or complicated by ongoing regulatory uncertainty and acts of civil disobedience.

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Despite these issues, the oil and gas industry remains a significant and important part of the Canadian economy. Moreover, the response of Canadian producers to the lower commodity prices of the past several years has set the stage to ensure that Canada remains a global force in the oil and gas industry, in particular as producers continue to embrace new technologies, improve efficiencies and reduce costs.
Chapter 7

CHINA

Jihong Wang, Ying Liu, Anjing Wu, Huiqi Zhao and Guanli Huang

I INTRODUCTION

China's oil and gas infrastructure continues to improve, and the oil and gas supply has been remarkably enhanced. Every five years, the National Development and Reform Commission (NDRC) and the Energy Bureau would 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.

The thirteenth five-year plan reveals that, as at the end of 2015, the total reserve of regular oil geology resource amounts to 108.5 billion tons while the total reserve of regular gas geology resources amounts to 68 trillion m³.

In terms of production, since 2000, China's domestic oil production has been exceeding 200 million tons for six years consecutively; in 2015, the national gas production hit 135 billion m³ in which the shale gas exploration production reached 4.6 billion m³. China continues to import oil and gas, with a speedy increase in gas importation. According to the 2017 Domestic and Foreign Oil and Gas Industry Development Report issued by a thinktank, in 2017, the national crude oil production continues to drop and was 192 million tons. In 2017, China's gas consumption was 238.6 billion m³, and the importation amount was 94.6 billion m³. Gas consumption increased unexpectedly, and in certain areas and certain times, gas was undersupplied, with LNG sales prices surging. Experts predict that China will become the biggest gas importer by 2019.

The development goals planned by the Chinese government in the area of oil and gas are to build a multipolar oil supply security system on open conditions, and to ensure an oil consumption of 590 million tons in 2020. With respect to regular gas, shale gas and coal bed methane, by 2020 the detected geology reserve of each will accumulate to 16 trillion m³, 1.5 trillion m³ and 1 trillion m³ respectively.

As for market access for foreign investors, according to the Industry Guiding Catalogue for Foreign Investment, the exploration and development of oil and gas fall into the encouraged industry category.

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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 decisive role of the market will be better played in resource allocation, and a modern oil and gas market system with fair competition, openness and order will be formed gradually.

## 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 are not allowed to independently develop oil and gas in China; however, they can cooperate 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 must 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

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2 See the Rules on Foreign Cooperation in Exploiting Offshore Oil Resources, and the Rules on Foreign Cooperation in Exploiting Onshore Oil Resources.
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.

**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.

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 licenses 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 licenses 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.\(^6\)

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, there are no restrictions on oil and gas production in China. For oil and gas obtained by foreign investors in accordance with the cooperative mining contracts signed by the Chinese and foreign parties, there is no legal restriction on exportation to foreign countries subject to sanctions of embargo.\(^8\)

For foreign investors willing to sell oil and gas in China, according to the Special Management Measures on Foreign Investment Access (Negative List) (2018 edition), the previous requirement has been cancelled, which stipulated that for enterprises invested in by the same foreign investor that has set up more than 30 branches, engaging in the sales of different types and brands of refined oil products from multiple suppliers and running the construction and operation of chain gas stations, the Chinese counterpart shall be the controlling shareholder therein. This means that currently no restriction is prescribed in terms of the distribution of oil.

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.\(^9\) 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.\(^10\) Pricing policies including the price ladder for residential usage and seasonal variable pricing can be applied.\(^11\)

\(^6\) 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.

\(^8\) Rules on Foreign Cooperation in Exploiting Onshore Oil Resources, Article 15; Rules on Foreign Cooperation in Exploiting Offshore Oil Resources, Article 9.

\(^9\) 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.
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:

a after the completion of the specified minimum exploration investment, the prospecting right holders can transfer the exploration rights to others with due approval;
b in case a mining enterprise which 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.

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 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.

VI TAX

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 include value added tax, resource tax, environmental protection tax and prospecting and mining loyalties.
Value-added tax
As of 1 May 2018, 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 17 per cent and 11 per cent\(^\text{14}\) has been adjusted to 16 per cent and 10 per cent\(^\text{15}\) 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\(^\text{16}\).

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,\(^\text{17}\) 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.\(^\text{18}\)

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

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, tax incentives ranging from 20 per cent to 40 per cent are applied respectively.\(^\text{19}\)

\(^{14}\) 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.
\(^{16}\) 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.
\(^{17}\) Environmental Protection Tax Law, Article 8.
\(^{18}\) Measures on the Administration of the Use of the Use Fees and Payments for Mine Prospecting and Exploiting Rights, Article 5.
\(^{19}\) Announcement on Adjusting Relevant Policies Regarding Oil and Natural Gas Resource Tax, Paragraph 2.
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.20

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.21 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, for both terrestrial and coastal 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.22

20 Environmental Protection Tax Law, Article 13.
21 Marine Environmental Protection Law, Article 50.
22 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.
ii Discharge permit
According to the Law on the Prevention and Control of Water Pollution and the Law on the Prevention and Control of Atmospheric Pollution, oil and gas enterprises that directly or indirectly discharge industrial waste water, industrial waste gas and other toxic and hazardous atmospheric pollutants shall obtain a discharge permit. For the dumping of marine waste involved in offshore oil exploration and development, the corresponding waste discharge permit should also be obtained.

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.

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. 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.

VIII FOREIGN INVESTMENT CONSIDERATIONS
i Establishment
Foreign companies engaged in oil and natural gas exploration and development need to do the business by means of joint ventures or cooperation with Chinese companies holding...

23 Water Pollution Prevention and Control Law, Article 21; Atmospheric Pollution Prevention and Control Law, Article 19.
24 Regulations of the People's Republic of China on the Control over Dumping Wastes into the Sea Waters, Articles 6 and 9.
exclusive rights. According to the Special Management Measures on Foreign Investment Access (Negative List) (2018 edition) published by the Ministry of Commerce on 28 June 2018, foreign companies engaged in oil and gas (inclusive of coal bed methane and exclusive of oil shale, shale gas and oil sand) are required to carry out the business by joint ventures or cooperation with Chinese oil companies. As for the Free Trade Zone, the requirement of ‘joint ventures or cooperation with Chinese oil companies’ has been removed regarding the exploration and development of oil and natural gas.

China National Petroleum and Natural Gas Corporation Group, China National Petroleum and Chemicals Corporation Group and China National Offshore Oil Corporation enjoy the exclusive right of cooperation with foreign companies in the area approved by the state council for oil and gas exploration, development and production. Foreign companies engaged in the exploration and development of onshore and offshore oil and gas in China must first sign a contract for the exploitation of oil (natural gas) resources with the above-mentioned Chinese oil companies. In addition, a foreign company shall legally establish a branch, subsidiary or representative office within China’s territory, with the specific location of branches be determined by the company after consultation with Chinese oil companies.

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.

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

On 30 June 2018, the Ministry of Commerce issued the Notice of the General Office of the State Council on Issuing the Special Management Measures (Negative List) for Foreign Investment Access in Pilot Free Trade Zones (2018 Edition) (hereinafter referred to as the Free Trade Zone Negative List 2018). Compared with the version of 2017, the Free Trade Zone Negative List 2018 has eliminated the restriction on foreign investors’ involvement in the exploration of oil and gas (inclusive of coal bed methane and exclusive of oil shale, shale gas, oil sand, etc.) that the requirement of ‘joint ventures or cooperation with Chinese oil companies’ has been removed. As the pioneer in the reform and opening in China, the Free Trade Zone has lifted restrictions on foreign investment in the field of oil and gas from the negative list, indicating a progressive trend in China’s further exploration and exploitation in the field of oil and gas.

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. In order to deepen the market-oriented reform in the oil and gas sector, China established the Shanghai Oil and Gas Trading Centre in the Shanghai Free Trade Zone in 2015. The trading centre has launched trading of natural gas, unconventional natural gas, liquefied petroleum gas, petroleum and other energy products. The mode of transaction includes traditional ways of listing and auction. Furthermore, the centre launched
an innovated mode of medium and long-term LNG presale supply contracts and bidding along with CNOOC, as well as a mode of group buying, indicating an ongoing sense of innovation in the trading mode to meet the needs of the market.

On 5 September 2018, in the Several Opinions on Promoting the Coordinated and Stable Development of Natural Gas issued by the State Council, it specified that the domestic exploration and exploitation of gas should fully implement the competitive system of block transfer, and the transfer of mining rights are encouraged to be conducted in a market-oriented manner. This shows China’s determination in further undertaking reform in the field of gas exploration and exploitation.

ii Huge demands in the market of oil and gas making alternative resources new focus

China is in the process of energy transformation, during which cleaner and more environmentally friendly energy such as 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.

Owing to the limited natural gas production, the construction of an integrated nationwide natural gas pipeline network has not yet been completed. The shortage of natural gas in northern China at the end of 2017 indicates that demand in the oil and gas market is huge.

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. In the mean time, China is also increasing overseas investment in unconventional oil and gas projects to meet the needs of the domestic market. In November 2017, during Mr Trump’s visit to China, China National Energy Investment Group plans to invest US$83.7 billion into the exploitation of shale gas and chemical project in West Virginia, which will last over two decades.
Chapter 8

COLOMBIA

José V Zapata Lugo and Claro M Cotes Ricciulli1

I INTRODUCTION

In July, 2018, Colombia held a new presidential election that concluded with the victory of the young candidate, Ivan Duque, former senator from the right-wing Democratic Centre party. The new government has a vision of attracting foreign investors through the implementation of regulations that promote industries such as the oil and gas sector. To that extent, various 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. Of particular attention will be defining the terms and conditions pursuant to which unconventional reservoirs will be sustainably developed and whether the new government will support such activities in a timely manner. Oil average production has slightly decreased in comparison to 2017, particularly when production on this year also decreased significantly in relation to the previous ones, fluctuating from an average production of 854 thousand barrels per day (KBPD) in 2017, to 848 KBPD up to May 2018.2 This confirms that the creation of exploration incentives continues to be a matter of urgency, considering the favourable conditions in neighbouring countries and that exploration activities continue to drop. However, in recent months the outlook for the sector has been very favourable, as, in comparison to the same months of the immediately preceding year, higher production has been achieved.3 Similarly, the National Hydrocarbons Agency (ANH) has seen increased proposals for new exploration and production contracts, and alongside Agreement 02 of 2017 and upcoming permanent contracting conditions, Colombia continues to advance in its attempt to provide structural reorganisations to reactivate the oil and gas industry, as well as legal stability that guarantees the rule of law, which was profoundly needed.

On the other hand, the current implementation of the peace process should continue to increase investors’ appetite for developing their business in Colombia, which may be enhanced by the issuance of the Agreement 02, 2017 and its potential 2018 modifications. In addition, the government has expressed its strong intention to bet for offshore production, which has been evidenced, for example, in new discoveries in the Colombian Caribbean sea.4

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2 http://www.anh.gov.co/Operaciones-Regalías-y-Participaciones/Sistema-Integrado-de-Operaciones/Paginas/Estadísticas-de-Produccion.aspx.
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.

With the recent election of new 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 2016, a total of 21 exploration wells were drilled in Colombia, compared with the 54 wells drilled in 2017.\(^5\) Oil reserves in 2017 were estimated at 1,782 million oil barrels,\(^6\) increasing from 2016, which had an estimate of 1,665 million oil barrels. Nevertheless, they still represent a significant decrease compared to the 2,002 million oil barrels reserve estimated in 2015.\(^7\)

Regarding gas production, as of April 2018 compared to 2017 one can detect a minor increase of 2.1 per cent in annual production, as production reached 938,771 million cubic feet per day. However, it continues to be a low 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.\(^8\)

There are still changes that need to be incorporated since the government must provide and ensure greater legal stability for investors, especially in matters relating to communities and social factors (prior consultation, territorial entities decisions, public consultations and the veto power), as well as establishing contractual terms that are much more attractive to investors.

II  LEGAL AND REGULATORY FRAMEWORK

In Colombia there is a clear differentiation between the oil and gas regulations: upstream, midstream and downstream. 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.\(^9\) Similarly, the basis for royalties is constitutionally

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6  www.portafolio.co/economia/aumentaron-las-reservas-de-petroleo-del-pais-516729.
7  https://www.datos.gov.co/Minas-y-Energ-a/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  Article 332 of the Colombian Political Constitution.
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.\textsuperscript{10}

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.\textsuperscript{11} 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.

\section*{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.\textsuperscript{12} Also, all data obtained during the course of scientific, technical, economic or statistical activities must

\textsuperscript{10} Article 360 of the Colombian Political Constitution.
\textsuperscript{11} Decree 968 of 18 May 1940.
\textsuperscript{12} Article 4 of Decree 1056 of 1953.
be provided to the Colombian government, as part of the duties that parties involved in the oil and gas industry must abide with.\textsuperscript{13} 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.\textsuperscript{14} 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.\textsuperscript{15} 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 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 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. Unconventional reservoir potential has provoked, as in other jurisdictions, debates on fracking. 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. The importance of unconventional hydrocarbon plays was further evidenced by the parallel work undertaken

\textsuperscript{13} Article 7 of Decree 1056 of 1953.
\textsuperscript{14} Article 1 of Resolution 181495 of 2009.
\textsuperscript{15} Article 4 of Resolution 181495 of 2009.
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 No. 02 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 said resources. Therefore, even though there is currently a ‘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 said 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.

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, recognizes 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 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.

ANH is currently in charge of administrating TEA and E&P contracts, leading to considerations of contract rules. Currently Agreement 02 of 2017, issued by the ANH, included 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 02, 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.

16 Article 212 of Decree 1056 of 1953.
17 Article 47 and following of Decree 1056 of 1953.
18 Article 196 of Decree 1056 of 1953.
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 amongst 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 02 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 02, 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.

\[\text{ii Regulation}\]

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 specialised
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 such permission, regional environmental authorities are the
ones authorised to approve such 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 such 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-382/06.20

iii Treaties

With the issuance of Law 39 in 1990,21 Colombia became a party to the 1958 New York
Convention.

21 Law 39 of 1990 approved the Convention on Recognition and Enforcement of Foreign Arbitral Awards
(the New York Convention) adopted by the United Nations Conference on Commercial Arbitration on
10 June 1958.
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:

- the Free Trade Agreement between Colombia and Peru and the European Union and its Member States as approved by Law 1669 of 2013;
- the Free Trade Agreement between Mexico and Colombia as approved by Law 1457 of 2011;
- the Free Trade Agreement between Canada and Colombia as approved by Law 1363 of 2009; and
- 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.

### 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 02 of 2017. However, note must be made that this Agreement determines that contracts subscribed before Agreement 02 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 02, 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 02 of 2017.

In accordance with Agreement 02 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.
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 02, 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 02, 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.

### III 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.

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22 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.

23 Reference can be made to Decree 1073 of 2015.
IV 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.

V 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 reduction24 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:

- corporate income tax (CIT): 33 per cent tariff;
- 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;
- 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;
- 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;

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24 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.
e VAT: All goods and services purchased locally are subject to a standard rate 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 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.

VI 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. Such fund may be done through any economic instrument approved by the ANH (i.e., trusts, bank guarantee). Said provision is mainly determined under contract, were ANH determines conditions of decommissioning fund.

VII 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.

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.

26 Article 100 of the Colombian Political Constitution.
27 ibidem.
28 Article 10 of Decree 1056 of 1953.
29 Article 3 of Law 10 of 1961.
VIII CURRENT DEVELOPMENTS

The election of Ivan Duque as president of Colombia for the following four years 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. 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. One cannot affirm that with the signing of the peace agreement, there will be an automatic improvement and growth of the hydrocarbons sector in Colombia, since it is considered the first step in a long process that requires close cooperation between the government and the oil and gas companies to stimulate the sector, which is still deeply influenced by the fall in oil prices.

It is worth mentioning that, despite the fact that 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 thus promote peace.

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 can 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 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) a modification to Agreement 2 of 2017 is foreseen to grant greater flexibility to the contractor in relation to the modification of the contractual terms, based on its investments.

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.
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 Oligram 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 such 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 AND SOCIAL SECURITY LAW

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 such 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 10

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 seven 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 has been 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 will conclude on 1 February 2019. According to the DEA, it is the aim to initiate additional rounds of applications about one year after the last round finished.

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. 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 Nordsøfonden4 in all licences granted since 2005 whether in a licensing round or through the open-door procedure with a 20 per cent stake.5 In addition, Nordsøfonden participates with a 20 per cent stake in the Sole Concession.

Denmark has been a net exporter of energy since 1997 and is self-sufficient in oil and natural gas. For 2018, the DEA anticipates an oil production of 8.2 million m³ and a production of natural gas (sales gas) of 3.5 billion normal cubic metre (Nm³). Denmark’s

1 Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleagues, attorney Lars Fogh for his contribution to the section on tax, and 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 and the seventh round concluded in April 2016. See further www.ens.dk.
4 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.
5 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).
reserves of oil are as of 1 January 2017 estimated to 135 million m³ and of sales gas to 59 billion Nm³, both figures including contingent resources. The DEA's forecast for Denmark's self-sufficiency in oil foresees that Denmark will be self-sufficient until 2018 and again between 2023–26. If advancements in technology, exploration resources, etc., are included, it is expected that Denmark will be close to self-sufficient until 2031 (except 2019–22). Turning to natural gas, the DEA forecasts that Denmark will be self-sufficient until 2019. The inclusion of advancements in technology, exploration resources, etc., results in an anticipated self-sufficiency in natural gas until 2035 with the exception of 2020–21.

Two political decisions mark the highlights of the Danish oil and gas industry so far in 2018: (1) the Danish government has decided to stop future onshore investigations and drillings for oil and gas; and (2) announced a new energy initiative, 'Energy – for a green Denmark' with the main purposes of ensuring more affordable energy and that at least 50 per cent of Danish energy is renewable by 2030.

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 continental shelf. Several of the provisions in the DSA implement EU directives. The DSA is based on the view that the exploration for and recovery of Denmark's raw materials covered by the act require comprehensive societal management.

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6 For details please refer to the publication ‘Resources and Forecasts’ by the DEA, last released 29 April 2017, available at www.ens.dk.
7 Please refer to the publication ‘Resources and Forecasts’ by the DEA, last released 29 April 2017, available at www.ens.dk.
8 Consolidated Act No. 960 of 13 September 2011 with subsequent amendments. The Act was most recently amended on 1 January 2018, which introduced improved third-party access; see Section IX.
9 Consolidated Act No. 1101 of 18 November 2005 with subsequent amendments.
10 Consolidated Act No. 277 of 25 March 2014 with subsequent amendments.
The DSA covers prospecting, exploration, exploitation, supervision as well as the Danish government’s rights of purchasing hydrocarbons and any other use of the subsoil.\footnote{12} All raw materials including hydrocarbons covered by the act belong to the Danish state.\footnote{13} Consequently, initiation of all major activities, such as investigation, exploration and production require a separate approval from the Danish Minister for Energy, Utilities and Climate\footnote{14} (DEA). With respect to the relevant European Union law, this allows the Danish government to make societal considerations, for example, and protect these through specific terms in each licensing round.

Licences for the exploration and production of oil and gas may be granted through licensing rounds and since 1997 Danish legislation has also provided for an open-door procedure.\footnote{15} Since 1983 areas in the North Sea have been offered to interested companies in a total of seven licensing rounds with an eighth round currently open for applications. A licence is granted on the basis of a model licence with supporting documents containing detailed terms and conditions and is an integrated part of any licensing round.

A licence is considered private property in Denmark and is governed by Danish law. A transfer of licence rights in the oil and gas regime is, however, subject to prior approval from the DEA; see further Section V.

In order to obtain a licence to initiate exploration of and extraction from the subsoil as referred to in the DSA, a fee of 25,000 kroner is payable.\footnote{16} Expenses borne by the authorities in relation to licensing activities under the DSA or in relation to the other activities governed by the DSA, CSA or DPA must be reimbursed by the relevant party.\footnote{17} Additionally, a licensee is obliged free of charge to submit samples and other information obtained in the exercise of activities covered by the DSA to the DEA and to the Geological Survey of Denmark and Greenland (GEUS).\footnote{18}

\textit{The Danish Continental Shelf Act}

The CSA is based on the UN Convention of the Continental Shelf.\footnote{19} 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.

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.\footnote{20}

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

\begin{thebibliography}{99}
\bibitem{12} Section 1(2) of the DSA.
\bibitem{13} Section 2 of the DSA.
\bibitem{14} Lars Chr. Lilleholt was appointed Minister for Energy, Utilities and Climate in June 2015.
\bibitem{15} See Section 1.
\bibitem{16} See Section 2 in the Statutory Order on the Payment of Fees connected with Certain Licences Issued pursuant to the Danish Subsoil Act No. 419 of 2 June 2005.
\bibitem{17} See the Statutory Order on Reimbursement of Expenses related to the Authorities’ Administration in connection with Hydrocarbon Activities, No. 661 of 1 June 2018.
\bibitem{18} See Sections 2 and 3 of the Statutory Order on Submission of Samples and other Information about the Danish Subsoil, No. 56 of 4 February 2002.
\bibitem{19} Ratified by Denmark on 31 May 1963.
\bibitem{20} See Section 1 of the CSA.
\bibitem{21} See Section 4 of the CSA.
\end{thebibliography}
**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 (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. 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. This obligation can be exempted by the Minister if the connection to the pipeline is considered uneconomical or inconvenient. 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.

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.

**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, the Act on Protection of the Marine Environment, the Environmental Impact Assessment Act, the Statutory Order on Offshore Impact Assessment (Statutory Order on OIA) and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.

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. 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.

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22 The pipelines are as part of the political agreement entered into regarding the IPO of DONG Energy A/S (now Ørsted A/S) to be divested to the state owned Danish TSO, Energinet.dk. The listing took place on 9 June 2016, but the divestment is still being negotiated between the parties.

23 See Section 1 of the DPA.

24 See Section 2 of the DPA.

25 See Section 2(3) of the DPA.

26 See Sections 3 and 3c of the DPA and Statutory Order No. 78 of 28 January 2018 on the payment for transport of crude oil and condensate.

27 See the Statutory Order No. 920 of 25 June 2018 on access to the upstream pipelines and upstream systems.

28 Consolidated Act No. 125 of 6 February 2018.

29 Consolidated Act No. 1033 of 4 September 2017 on the Protection of the Marine Environment with subsequent amendments.

30 Consolidated Act No. 448 of 10 May 2017 on Environmental Impact Assessment of Plans and Programmes and of Specific Projects 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.
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 shall 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 Energy, Utilities and Climate 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 for the Danish national CO2 targets and initiatives to limit emissions of greenhouse gases. The power to award licenses 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 of Energy, Utilities and Climate, 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

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35 Section 1 of the Statutory Order No. 657 of 30 December 1985.
36 See Consolidated Act No. 862 of 19 June 2014 with subsequent amendments.
37 See Consolidated Act No. 966 of 20 September 2011 with subsequent amendments.
38 See Statutory Order No. 1512 of 15 December 2017 on the DEA’s duties and powers.
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.
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 Justice\(^{45}\) 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 DSA\(^{47}\) based on one of the licensing methods outlined in Section II.i. The DEA has finalised seven rounds\(^{48}\) of applications for licenses 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. An eighth round for the same area is open for applications until 1 February 2019.

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.

Nordsøfonden\(^{49}\) 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 the 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.

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42 See Section 37 (a) of the DSA.
45 Consolidated Act No. 1101 of 22 September 2017 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.
49 See Section I.
The main terms of the model licence for the eighth round are as follows:

a delineation of the area where the licensee obtains the exclusive right to explore for and – in the case of commercially exploitable finds – produce oil or natural gas or both. Certain other rights may be allocated to third parties;50

b the frame for the work programme to be adhered to by the licensee;51
c the obligation to enter into a joint operating agreement within 90 days following granting of the licence;52
d extensive information requirements to the DEA and the DEA’s rights of participation as observer as well as confidentiality obligations;53
e liability issues (strict liability), insurance obligations, obligation to provide security;54
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;55
g the full immunity granted by the licensee regarding any claim that may be raised against the Danish state following the licensee’s activities;56 and

h dispute resolution (the ordinary Danish courts unless agreement on arbitration) with venue in Copenhagen. It goes without saying that any licence issued is subject to Danish law in force from time to time.57

As mentioned, if there are several parties to a licence 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 terms of the model JOA included in the seventh58 licensing round 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

50 The model licence terms Sections 2 and 3 with Annex 1.
51 ibid., Section 4 with Annex 2.
52 ibid., Section 18.
53 ibid., Sections 19–22.
54 ibid., Sections 30–32.
55 ibid., Sections 34–37.
56 ibid., Section 38.
57 ibid., Section 40.
58 A model JOA for the eighth round had not been published at the time of writing.
granted on terms restricting dimensions, transport capacity, ownership, etc.\textsuperscript{59} There are no further restrictions on production entitlements except for oil in crisis situations (oil reserve stocks).\textsuperscript{60} 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,\textsuperscript{61} 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,\textsuperscript{62} prices, terms and conditions are negotiated between the parties.\textsuperscript{63} 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.\textsuperscript{64}

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 conditions attached to such transfer.\textsuperscript{65} 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.\textsuperscript{66} 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.\textsuperscript{67} 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\textsuperscript{68} or a licence to establish or operate upstream

\textsuperscript{59} DSA, Section 17(2).
\textsuperscript{60} DSA Section 17a and Act No. 354 of 24 April 2012 on oil minimum stocks with subsequent amendments.
\textsuperscript{61} Statutory Order No. 920 of 25 June 2018.
\textsuperscript{62} ibid.
\textsuperscript{63} See Section 5 of the Statutory Order on Access to Upstream Pipelines.
\textsuperscript{64} ibid.
\textsuperscript{65} See DSA Section 29(1).
\textsuperscript{66} A provision to this effect is also included in the model licence for the eighth round, Section 33.
\textsuperscript{67} See DSA section 29(2).
\textsuperscript{68} cf. DSA Section 5.
pipelines\textsuperscript{69} 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.\textsuperscript{70} 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.\textsuperscript{71} Licences issued pursuant to the Subsoil Act enjoy immunity from legal prosecution.\textsuperscript{72}

VI TAX

i 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\textsuperscript{73} and the Hydrocarbon Tax Assessment and Collection Act.\textsuperscript{74}

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 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 the Danish Tax Authorities (SKAT). The relevant forms and further information can be found in English on the Danish Tax Authorities’ website.\textsuperscript{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, \textit{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.\textsuperscript{76}

\textsuperscript{69} Cf. DSA Section 17.
\textsuperscript{70} See DSA Section 29a.
\textsuperscript{71} Statutory Order No. 661 of 1 June 2018 on the reimbursement of costs with subsequent amendments.
\textsuperscript{72} Cf. DSA Section 29(3).
\textsuperscript{73} Consolidated Act No. 862 of 19 June 2014.
\textsuperscript{74} Consolidated Act No. 966 of 20 September 2011.
\textsuperscript{75} See www.skat.dk.
\textsuperscript{76} I.e., for separate income under Part 2 and for hydrocarbon income pursuant to Part 3A of the Hydrocarbon Tax Act.
ii Tax rates and income types

The two-string Danish hydrocarbon tax system combines corporate income tax at the rate of 25 per cent (Chapter 2 income) and a special hydrocarbon tax at a rate of 52 per cent (Chapter 3A income) for the income year of 2018. The overall effective tax rate for Chapters 2 and 3A income is 64 per cent for the income year of 2018.

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, \textit{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 2018.

iii Ring-fencing

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. As of 1 January 2014, the field ring-fence has been repealed, whereby tax losses from one field may be offset against a profitable field.

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 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.

As mentioned above, political agreement has been reached to reduce taxation for oil and gas exploitation in an ‘investment window’ from 2017–25. The agreement provides for, \textit{inter alia}, a raise in the hydrocarbon deduction from 5 to 6.5 per cent and an advanced phasing for deductions.

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.,\textsuperscript{78} and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.

\textsuperscript{77} The ordinary corporate income tax of 22 per cent added 3 per cent for hydrocarbon activities for 2018.

\textsuperscript{78} Statutory Order No. 909 of 10 July 2015.
Licences for offshore projects involving a risk of affecting the environment may only be granted and utilised pursuant to an environmental impact assessment (EIA)\(^79\) and an impact assessment regarding international nature conservation\(^80\) as well as after consultation with the members of the affected general public, authorities and organisations.\(^81\)

Exploration activities like pre-investigations (for example, seismic surveys) and drilling may not always require the preparation of an EIA or other impact assessments.\(^82\) Any planned work, including well drilling, shaft sinking, driving adits and drifts, may only be initiated after obtaining prior approval from the DEA.

ii 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.

iii 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.

iv 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.\(^83\) The licensee is required to have the capacity to remove all or part of any facilities, installations, etc.\(^84\)

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\(^79\) Under the Environmental Impact Assessment Act.

\(^80\) See Sections 28(a), 28(b) and 28(c) of the DSA and the Statutory Order on OIA.

\(^81\) See Section 35 of the Environmental Impact Assessment Act and Section 6 of the Statutory Order on OIA.

\(^82\) 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, procedures to follow).

\(^83\) See the DSA, Section 8.

\(^84\) See the DSA, Section 24(a).
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\textsuperscript{85} and the terms and conditions stated in the licensing documents. Among these criteria is, \textit{inter alia}, a requirement to demonstrate the necessary expertise and financial resources.\textsuperscript{86} 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.

IX CURRENT DEVELOPMENTS

As mentioned in the introduction, the Danish government has announced a new energy initiative in April 2018; ‘Energy – for a green Denmark’.\textsuperscript{87} The initiative is intended to ensure that at least 50 per cent of Danish energy will be renewable by 2030 and that energy will become more affordable – all part of a greater plan to make Denmark independent of fossil fuels by 2050. The overall initiative is backed by various detailed proposals, such as one for the largest sea wind turbine park in Denmark and one for the reduction of tax on electricity and electrical heating. Additionally, the government announced in February 2018 that future onshore investigations and drillings for oil and gas will be stopped.\textsuperscript{88}

While this may appear to signal grave prospects for the Danish oil and gas industry, North Sea production is in fact given priority until 2050, as the government recognises that the green transition will take time. In the meantime, Denmark will benefit from being self-sufficient, and Danish oil and gas production is still considered to be of importance to the Danish economy.

The focus on the North Sea is in line with the recommendations of the Committee for the Preparation of an Oil and Gas Strategy, which was published in July 2017. The Committee concluded that Denmark has a substantial potential of roughly three billion barrels oil equivalents (BOE) compared to the 3.8 billion BOE already produced (2015 figures) and recommended promoting investments by increasing the potential for exploitation and by reducing barriers for utilisation of this potential.

Following one of the Committee’s recommendations, the DSA was amended on 1 January 2018\textsuperscript{89} in order to improve third-party access to the infrastructure in the Danish

\textsuperscript{85} See the DSA, Section 12(a).
\textsuperscript{86} ibid.
\textsuperscript{87} See the news statement from the Danish Ministry of Energy, Utilities and Climate, released 26 April 2018, available at www.efkm.dk.
\textsuperscript{88} See the news statement from the Danish Energy Agency, released 22 February 2018, available at www.ens.dk.
\textsuperscript{89} By Act No. 1,400 of 5 December 2017. The Act also amended the DPA with a view to improve the use of the pipeline capacity in further support of the production from the North Sea.
part of the North Sea. This entails that a licensee will be able to obtain access to another licensee’s infrastructure on predictable and reasonable terms, which is expected to improve the potential for commercially sound exploitation of the relatively smaller finds of oil and gas comprising most of the Danish potential in the North Sea.

The amendment to the DSA is also in line with the political agreements reached in March 201790 with the purpose of securing an ‘investment window’ in 2017–25 with temporary tax reductions and a full restoration of the Tyra field in addition to improved third-party access. Honouring these agreements, preparations for the restoration of the Tyra field are also currently in progress after Maersk Oil and Gas91 announced a 21 billion kroner investment in December 2017.

90 Between the government, most of the political parties in Parliament and the partners behind the Sole Concession.
91 Further to closing of Total’s 47 billion kroner acquisition of Maersk Oil and Gas on 8 March 2018, the company has changed its name to Total E&P Danmark.
Chapter 11

FRANCE

Yves Lepage and Geoffroy Berthon

I  INTRODUCTION

Located in more than 60 fields mainly in the Paris region and in the south west (Aquitaine Basin), French hydrocarbon deposits produced 790 tonnes of oil and 0.3 tonnes of oil equivalent (Mtoe) of natural gas in 2013, representing roughly 2 per cent of France’s annual consumption.

A major law known as the Energy Transition for Green Growth was enacted in France in August 2015. The main provisions of the law relate to the promotion of the use of renewable energy and do not specifically relate to oil and gas despite the law setting the reinforcement of energy independence and diversification of energy mix as identified goals. The 2011 law prohibiting the use of hydraulic fracturing remains in place.

In addition, recent developments in the French exploration and production regulatory framework involve an extensive redrafting of the French New Mining Code (NMC) currently in force, which was first announced in 2012. On 6 September 2017, the Minister for the Ecological and Solidarity Transition announced the introduction of a new legislation providing for the end of the research and exploitation of conventional and non-conventional hydrocarbons (see below).

II  LEGAL AND REGULATORY FRAMEWORK

i  Domestic oil and gas regulation

Established in 1810 and revised in 2006, the NMC serves as the primary regulatory framework regarding oil and gas licensing, although publication of a new code is expected in the future.

Pursuant to Article L. 111-1 of the NMC, the exploration and production of gaseous or liquid hydrocarbons reserves are submitted to the legal regime applicable to the development of mines. The legal regimes for both oil and gas are therefore identical with respect to the issuance of mining titles, the rights granted to the holders of such titles, the completion of works and the control measures applicable.

Other pieces of the legal and regulatory framework applying to hydrocarbons exploration and production activities include environmental provisions (Article L. 161-1 of the NMC, cross-referencing the Environmental Code and the Estate Code) and decommissioning procedures (Articles L. 163-1 et seq. of the NMC).

In France, the operation of LNG terminals does not fall within production activities and the relevant regulation applying to LNG facilities is included in the French Energy

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1 Yves Lepage is a partner and Geoffroy Berthon is of counsel at Orrick, Herrington & Sutcliffe.
Code, which notably imposes certain public service obligations on the operators to guarantee the continuity and security of gas supply, and also provide for a tariff-setting mechanism monitored by the Energy Regulatory Commission.

ii   Treaties
France is a signatory to, and has duly ratified, the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards, the 1965 International Convention on the Settlement of Investment Disputes between States and nationals of other States, the 1994 Energy Charter Treaty and the 2004 Convention for the Protection of the Marine Environment and the Coastal Region of the Mediterranean (formerly known as the Barcelona Convention).

France is also a party to more than 120 bilateral tax treaties.

iii   Regulatory authorities
The minister responsible for mines (currently, the Minister of Environment, Energy and Sea) is the relevant French governmental authority responsible for the hydrocarbon sector. Pursuant to Article L. 171-1 of the NMC, the French regulations regarding mines aim to control and monitor all exploration and production works. Article 24 of Decree No. 2006-649 dated 2 June 2006 (as amended from time to time, the 2006-649 Decree) specifically entrusts the prefects (i.e., the French state’s representatives in a department or region) with the performance of such tasks at a local level.

Within the Ministry for Mines, the Department of Energy and Climate (DGEC) is responsible for defining and implementing the French energy policy. Within the DGEC, the Hydrocarbons Exploration-Production Bureau (BEPH) manages and promotes the French mining (hydrocarbon) sector. As such, the BEPH is associated with the award and renewal process of exploration (research) and exploitation permits. Within the DGEC, the Geological and Mining Research Bureau, is a public industrial and commercial institution, acting under the joint supervision of the Ministry for Higher Education and Research and the Ministry for Environment, Energy and Sea, in charge of collecting, classifying and keeping data on the French subsurface.

Disputes related to the mining sector, including breaches of the provisions of the NMC are settled before the French administrative or civil courts. Criminal offences are settled before the criminal courts. Certain disputes involving the midstream and downstream sectors may be submitted to a specific dispute resolution forum for the energy sector within the Energy Regulatory Commission.

III   LICENSING
i   Exploration
Article L. 121-1 of the NMC identifies three exploration regimes, depending on whether the landowner is conducting or consented to the exploration works, the administration authorised the exploration works to be carried out without the consent of the landowner, or exploration works are carried out following the issuance of an exclusive exploration permit.

The landowner prospecting its own property may freely dispose of the proceeds of its exploration works, without requiring any authorisation from an administrative authority,
which derives from its right of normal use of the land. However, should the land fall within
the scope of a concession, a state exploitation, or an exclusive exploration permit, the rights
of the landowner will be trumped by the rights of the holders of such titles or permits.

The administrative authorisation entitles the prospector to collect the proceeds of its
exploration works without the consent of the landowner, despite the landowner conducting
exploration on the land, or contemplating the same. This authorisation does not grant
the prospector any exclusivity on the land within the scope of the authorisation, as two
prospectors may conduct exploration works on the same land. In practice, exploration works
are rarely conducted under such regime, and are usually undertaken either with the consent
of the landowner or under an exclusive exploration permit (H permit).

The holder of an H permit is vested with an exclusive right to undertake exploration
works within the area defined in the permit, and may freely dispose of the products that
might be extracted as a result of these exploration works. This is the most favourable regime
for a prospector, due to its exclusivity and preferential status over the other two regimes.

An H permit is granted for a maximum initial five-year period, after a competitive
bidding process. It may be renewed twice, each for an additional minimum three-year period
(or, if the initial period was for less than three years, for the same minimum period) and a
maximum five-year period, without any requirement to resort to another bidding procedure
but subject to the permit holder’s compliance with its obligations and a financial commitment
at least equal to the commitment assumed during the initial period of validity of the permit.

The application must be submitted to the Minister for Mines, and must include
documents identifying the applicant, a technical memorandum, the contemplated work
programme, a minimum financial commitment, and cartographic documents. Financial and
technical capacities of the applicant, as well as the quality of the studies conducted in the
development of the work programme, are key elements to be considered in the application
process.

As of 1 January 2013, the application for an H permit must be made available to the
public by electronic means prior to the issuance of the permit by the administrative authority.
Once the application file is received, the Minister will publish a call for competition in both
French and European Official Gazettes. Potential bidders then have 90 days to submit a
competing application.

The H permit ensures the prospector that the right to develop the land will not be
awarded to a competitor while he or she still holds the exclusive exploration right. Pursuant
to Article L. 132-6 of the NMC, upon request and before its expiration, the holder of an
H permit can obtain a concession right over the workable deposits discovered pursuant to
the exploration works conducted under the permit. This right extends to the perimeter of
this permit and the substances mentioned therein, though the area covered by the permit is
reduced by half at the first renewal and again at the second renewal.

The application for an extension must be filed at least four months prior to the expiry
of the mining title with the Ministry responsible for Mines (Article 46 of Decree No. 2006-648
dated 2 June 2006 (as amended from time to time, the 2006-648 Decree)). The Ministry
is required to respond to such renewal request within 15 months from the date of filing.
However, if the Ministry does not respond within such period, the mining title shall remain
in place. This has been recently confirmed by the highest French administrative court, the
Council of State (CE, 17 July 2013, Société Hess Oil France, No. 365671), which ruled that
the withdrawal of a mining title requires an explicit decision from the French administration.
Therefore, the silence of the Ministry at the end of the 15-month period will not result in the termination of the mining title and the mining title holder may continue to operate as long as no explicit denial has been notified to it.

ii Development and production

Natural gas and oil reserves may only be developed under a concession granted by decree of the Council of State if the developer has sufficient technical and financial capacities. If the developer is not yet the holder of an H permit on the contemplated perimeter, the concession will be subject to a competitive bidding process.

The concession is granted for a maximum 50-year period and may be extended for additional periods of time that may not exceed 25 years each.

The concession agreement generates a real estate right, distinct from the property right of the owner of the surface where the reserve is developed, which nevertheless may not be mortgaged. It vests its holder with both the right to develop the reserves and the exclusive right to conduct exploration works within the perimeter of the concession.

The concession request must be filed with the Minister for Mines, together with a certificate providing information related to the applicant, a technical memorandum, a description of the development works, cartographic documents and a commitment to fulfil the terms and conditions of the concession.

The application for a concession is publicly disclosed, in accordance with the provisions of the French Environmental Code. The public may be informed through all appropriate means, by public display, local publication or electronic means. A public enquiry may last for 30 days.

IV PRODUCTION RESTRICTIONS

French public service requirements may result in restrictions to oil and gas supplies and sales. In accordance with Article L. 143-1 of the Energy Code, the French government may, for a specified period, impose a control and allocate energy resources in order to remedy an energy shortage or when the French external trade balance is threatened. National defence requirements, as defined by the Code of Defence, may also trigger the control and allocation of resources.

V ASSIGNMENTS OF INTERESTS

Interests in a permit or a concession may be transferred through either the assignment or leasing of mining titles. Pursuant to Articles L. 143-1 et seq. and L. 143-9 et seq. of the NMC, transfers require the prior authorisation of the Minister for Mines (Article 52 of the 2006-648 Decree) but is not subject to competitive bidding or specific publicity.

Pursuant to Article L. 143-2 of the NMC and 2006-648 Decree, the transferee of a mining title must meet the following technical and financial requirements:

a in accordance with Article 4 of the 2006-648 Decree, the prospective transferee must produce its credentials (such as the background of its officers and technical team), its significant mining references and an outline of the human and technical resources budgeted for the performance of the work; and

b in accordance with Article 5 of the 2006-648 Decree, the prospective transferee must also produce balance sheets, income statements and any proposed guarantees.
The 2006-648 Decree specifically allows the attribution of mining titles to several companies, acting jointly and severally (Article 43-3°), which makes the execution of joint operating agreements possible. Similarly, the 2006-648 Decree authorises share deals pursuant to which the control of the mining title holder is be transferred and deals resulting in a third party enjoying all or part of the production. However, transfers of interests, shares or rights to production under such deals require a prior ‘non-opposition’ from the Minister for Mines, who will essentially consider the financial and technical capabilities of the prospective transferee(s). Under Article 43-4° of the 2006-648 Decree, opposition from the Minister must be notified to the transferor within two months from receipt of the comprehensive file.

The transaction documentation usually includes, as a condition precedent to closing, the approval of the Minister for Mines.

Other events requiring mining title holders to request a ‘non-opposition’ pursuant to Article 43 of the 2006-648 Decree include material modification of the mining title holder’s articles of association and the occurrence of any material event that may result in the mining title holder’s technical and financial capacities (as determined at the time the mining title was awarded) being altered.

VI TAX

i Royalties on production from onshore deposits

Production of gaseous and liquid hydrocarbons gives rise to the payment of various royalties:

a a royalty due by the holder of the title to the owner of the surface, as provided in the relevant concession agreement. However, this amount has become symbolic and is now barely used;

b a royalty paid to departments or cities and calculated based on each net ton of product extracted by the holders of concessions of mines, lessees or sub-lessees of such concessions, holders of exploitation permits of mines and explorers of oil and combustible gas mines; and

c a progressive royalty paid to the state for onshore operations by holders of a concession covering onshore gaseous or liquid hydrocarbons, at a rate based on the volume of production (Article L. 132-16 of the NMC).

Article L. 132-16 differentiates between recent and old productions in the computation of this progressive royalty. Old productions include all wells in operation before 1 January 1980, through classical means of production. Any other production is deemed a recent production.

With regard to crude oil, the rate per annual tranche of production, in tons, is as follows:

<table>
<thead>
<tr>
<th>Production</th>
<th>Old production royalty rate (per cent)</th>
<th>Recent production royalty rate (per cent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under 50,000</td>
<td>8</td>
<td>0</td>
</tr>
<tr>
<td>Between 50,000 and 100,000</td>
<td>20</td>
<td>6</td>
</tr>
<tr>
<td>Between 100,000 and 300,000</td>
<td>30</td>
<td>9</td>
</tr>
<tr>
<td>Over 300,000</td>
<td>30</td>
<td>12</td>
</tr>
</tbody>
</table>
With regard to gas, the rate per annual tranche of production, in millions of cubic metres, is as follows:

<table>
<thead>
<tr>
<th>Production</th>
<th>Old production royalty rate (per cent)</th>
<th>Recent production royalty rate (per cent)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Under 300</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>Over 300</td>
<td>30</td>
<td>5</td>
</tr>
</tbody>
</table>

Under Decree No. 81-373 of 15 April 1981, the progressive royalty is based on the value of the extracted products, its value set at a price corresponding to the price of hydrocarbons of similar quality (determined pursuant to standard practice in the petroleum industry) on the French hydrocarbons market.

**ii  Royalty on production from offshore deposits**

Article L. 132-16-1 of the NMC contains specific provisions with respect to the calculation of the progressive royalty applicable to gaseous or liquid hydrocarbons extracted from offshore deposits. As from 1 January 2014, sales of gaseous or liquid hydrocarbons extracted from offshore deposits are subject to a progressive royalty that is calculated by applying a specific rate to several annual production tranches, all further determined in a decree that has not yet been published.

Article L. 132-16-1, however, provides that, in order to determine the various tranches and associated rates for such royalty, such decree shall take into account the nature of the products, the continent next to the deposits, the depth of the deposits, the minimum financial commitments subscribed by the operator for the exploration and development phase. Fifty per cent of the proceeds deriving from the levy of that royalty will be allocated to the French state and the remaining 50 per cent will be allocated to the French region that is closest to the offshore deposits.

The parliamentary works relating to such new provisions show a clear intention of the French government to further enhance the development of the hydrocarbon resources in French Guiana, still seen as one of the most promising French offshore areas, and to promote economic development in this overseas region bordering Brazil.

**iii  Other taxes**

In addition to the royalty regime, operators are subject to the standard French corporate income tax due on French-source taxable profits at the rate of 33.3 per cent (for the fiscal years open until 31 December 2016 – for the next fiscal years, the rate will decrease gradually to 28 per cent in 2020). A social surtax of 3.3 per cent applies if (1) the company’s turnover exceeds €7.63 million and (2) the company’s corporate income tax expense exceeds €763,000 (i.e., with a net taxable profit exceeding €2.289 million), giving rise to an effective tax rate of 34.43 per cent. In addition, a temporary 10.7 per cent surtax may also apply to the fiscal year that closed on 30 December 2015 if the company’s turnover exceeded €250 million, giving rise to an effective tax rate of 38 per cent.

Several other specific taxes regarding consumption also apply, such as the domestic consumption tax on petroleum products (Article 265 of the Customs Code), the domestic consumption tax on natural gas (Article 266 of the Customs Code) and VAT on oil products (Article 298 of the General Tax Code). Those taxes are mainly governed by European law (Directive 2003/96/EC dated 27 October 2003 restructuring the Community framework for the taxation of energy products and electricity).
VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

As mentioned above, operators must comply with the environmental provisions specified under Article L. 161-1 of the NMC, which set forth general environmental objectives that shall be fulfilled, and cross references various sections of the Environmental Code and the Estate Code for further details.

As provided under Articles L. 163-1 et seq. of the NMC, decommissioning occurs when a particular infrastructure ceases to be used for the purpose of exploitation and applies to all installations and related works at the end of a specific work programme; and all installations and related works that have not been subject to a specific decommissioning procedure at the expiry of the exploitation period.

The mining title holder shall file a declaration of cessation of works no less than six months prior to the termination of the exploration or development works (Article 43 of the 2006-649 Decree) and inform the authorities as to how it intends to comply with the requirements of Article L. 161-1 of the NMC. This provision relates to safety and the environment, remediation of any nuisance triggered as a result of said activities or its prevention, and if necessary arrangements for a possible restarting of the activity.

Following those declarations, the administrative authority may prescribe appropriate additional measures in the event that the proposed measures are deemed inadequate, as well as the time frame for implementation of such measures. Pursuant to Article L. 163-7 of the NMC, in the event of a failure by the explorer or developer to satisfactorily implement the prescribed measures, the administrative authority may carry out or request a third party to carry these measures at the expense of the explorer or developer.

Upon satisfaction of the measures that have either been proposed by the explorer or the developer or prescribed by the administrative authority, a specific notification to that effect will be sent to the explorer or the developer.

VIII FOREIGN INVESTMENT CONSIDERATIONS

French law does not contain any nationality requirement in connection with bids for exclusive exploration permits or concessions or in connection with a transfer of interests in a permit or concession.

However, Decree No. 2014-479 dated 14 May 2014, which modified Article R. 153-2 of the French Monetary and Financial Code (CMF), subjects certain foreign (i.e., non-EU) investors to prior approval of the Minister of Economy for certain types of investments. This applies where an activity is essential to guarantee the interests of the state with regard to public policy and security or national defence, including the supply of electricity, gas, hydrocarbons or other sources of energy.

Such foreign investment will fall within this approval requirement if it consists of (1) the acquisition of a controlling interest in a French company whose main activity is subject to Decree No. 2014-479, (2) the acquisition of all or part of a branch of activity of the French company or (3) the acquisition of more than 33.33 per cent of the shares of such French company.

Strictly speaking, the acquisition of interest in a French company holding one or more mining title or titles for the purposes of carrying out exploration-production works only should not trigger the application of the above-mentioned provisions that restrict the prior approval procedure to any such companies involved in activities that are essential to guarantee the country’s public policy, public safety or national defence interests, such as the integrity,
security and continuity of supply of gas and hydrocarbons. If in doubt, Article R. 153-7 of
the CMF expressly provides that the Minister for Economy may be asked to determine within
two months whether a specific investment may fall within the scope of Decree No. 2014-479.

IX  CURRENT DEVELOPMENTS

A reform of the NMC has been anticipated for several years. In January 2017, the National
Assembly approved new provisions of the NMC in order to conform the NMC to new
environmental constraints. The new provisions remain to be adopted by the Senate in order
to be enforceable.

The main features of the reform included the following:

a the exploration and exploitation of mines require the prior deliverance of mining titles,
   which are divided into two categories: exploration titles and exploitation titles;
b the information and consultation procedure for the participation of the public would
   be enhanced for the issuance of mining titles;
c when the mining title is delivered, the representative of the state in the department may
   form a special monitoring committee; and

d a High Council of Mines will be formed to foster a strategic dialogue between the
   parties involved in the exploration and exploitation of subsurface resources.

This reform project did not intend to mitigate or end the ban (provided by the provisions of
Law No. 2011-835, dated 13 July 2011) of the use of hydraulic fracturing for the exploration
and production of liquid or gaseous hydrocarbons. The French Constitutional Council
confirmed in 2013 that this ban was compliant with the French Constitution (Decision

Finally, it should be noted that on 6 September 2017, the Minister for the Ecological
and Solidarity Transition presented a draft bill that aims to ‘to ensure the coherence of the
policy of managing hydrocarbons contained in the French subsoil with the Paris Climate
Accord’. In this perspective, the draft provides for the following points:

a an immediate ban on the issuance of new hydrocarbon exploration permits in the
   country, so that no research or exploitation of gaseous hydrocarbons can be carried out;
   and

b concessions currently in force cannot be extended for a term expiring beyond 2040.

At the date of drafting of the present chapter, this bill was adopted by the National Assembly
but it remains to be adopted by the Senate in order to be enforceable.

i  Law No. 2017-1839 of 30 December 2017

Law No. 2017-1839 of 30 December 2017 is aimed at respecting the French carbon
neutrality commitment by 2050 announced in the ‘Climate Plan’ of 7 July 2017 presented
by the French minister of energy. It is part of the French energy policy to promote renewable
energy and to reduce fossil fuels consumption.

For Nicolas Hulot, the French minister of energy at the date of publication of the law,
‘this law ensures the consistency of our law with our climatic commitments made in the Paris
agreement. It brings our country in compliance with the objective to fight climate change.
Indeed, to stay below the limit of 2°C, we must abandon almost all subsoil fossil fuels. That is allowed by this project of law, which also confirms that France definitely bans the research on, or the operation of, shale gas.’

According to the minister, ‘it is a first step toward a fossil fuels detoxification. We are henceforth continuing working to reduce our fossil fuels consumption, in transport, in housing or in electricity production. This law draft brings our partners in the same direction, as illustrated by the commitments made during the One Planet Summit.’

This Law radically changes the legal framework applicable in France, three modifications being noteworthy enough to be mentioned.

**Immediate ban of the issuance of new hydrocarbons permits**

Under French law, (1) the exploration works are subject to the issuance of an exclusive exploration permit; and (2) the development and production are subject to the issuance of a concession.

Law No. 2017-1839 of 30 December 2017 henceforth provides for the immediate ban of the issuance of (1) new hydrocarbons exploration permits, including for experimental purposes, and (2) new concessions for these substances.

**No extension of current permits and concessions beyond 2040**

The exploration permits and concessions that have been issued before the entry into force of the new law remain enforceable but cannot be extended beyond 1 January 2040.

An extension of the duration of the permits and concessions is possible beyond 2040 only if the holder of the permit demonstrates that the limitation of the duration to 2040 does not allow the holder to cover its exploration and operational costs in order to reach the economic equilibrium for the operation of the substance identified in the scope of the permit.

**Prohibition of shale gas research and operation**

The law provides that the research and the operation of oils by hydraulic fracturing or by any other non-conventional method are prohibited.

According to the Law, this interdiction is implemented in accordance with the Charter for the environment of 2004 and the principles of preventive action and of rectification (the *principe d’action préventive et de correction*) provided for by Article L. 110-1 of the French Environmental Code.

**Summary**

In a nutshell, the Law provides that the research and the operation of coal and all other liquid or gaseous hydrocarbons, notwithstanding the technique used, are progressively terminated in France. The final goal is to reach a definitive cessation of these activities in 2050.

Furthermore, the Law brings the following obligations:

a. within one year of the enactment of the Law, the government has to hand over to Parliament a report on the support of companies and workers impacted by the progressive end of hydrocarbons exploration and operational activities and on the regeneration of the impacted territories; and

b. before 31 December 2018, the government has to present to Parliament another report assessing the environmental impact of crude and refined oil and natural gas released for consumption in France.
Chapter 12

GERMANY

Matthias Lang and Laura Linde

I INTRODUCTION

Germany produces little domestic oil and natural gas and relies heavily on imports. In 2017, only 2 per cent of oil and 7 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 2017, annual oil production amounted to 2.2 million metric tons, which represents a decline of about 6 per cent from 2016 levels while production of natural gas declined by about 8 per cent and amounted to 7.3 billion cubic metres. On 1 January 2018, Germany had proved and probable reserves of about 28.3 million metric tons of oil and 63.1 billion cubic metres of gas. Active drilling activities have been cut by half, down to four exploration wells, while the number of field development wells has increased to 20 compared to 18 in 2016.

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 Berlin Court of Appeal, for her contribution to this chapter.

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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. Germany’s only two offshore oil and gas fields are located in the North Sea.

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.

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.

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10 Section 48 Federal Mining Act. An English translation is available at http://www.gesetze-im-internet.de/englisch_bberg/english_bberg.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.
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.17

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.18 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.19 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.20

The application for exploration and extraction licences or mining proprietorship has to be made in writing to the competent authority.21 The application shall include inter alia specifications of the exact resource to be explored or extracted and detailed specifications of the mining area.22

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.23 Freely mineable resources include hydrocarbons and any gases generated during the extraction process.24 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 such resources.25

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. 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. 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.

The duration of an exploration licence is limited to a maximum of five years. 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.

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. 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.

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.

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. An exploration licence can also be revoked if exploration has not commenced one year after the license was granted due to reasons the licence holder is responsible for or if scheduled exploration is interrupted for more than one year. 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. Exploration or extraction licences can also be revoked partially or entirely at the request of the licence holder.

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 as well as in specified nature reserves. 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.

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. 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.

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. 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. Approval is considered granted if permission was not denied within two months of receipt of the request for permission.

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.

36 Section 18(3) Federal Mining Act.
37 Section 19(1) Federal Mining Act.
38 Section 13a(1) No. 2 Federal Water Act.
40 Section 3(1) Federal Oil Stock Act.
41 Section 22(1) Federal Mining Act.
42 Section 22(1) Federal Mining Act.
43 Section 23(1) Federal Mining Act.
44 Section 23(2) Federal Mining Act.
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) if this is required to prevent an overall economic imbalance; (2) if required to prevent risk to the competitive position of the exploration or extraction companies; (3) if required to ensure the supply of raw materials to the market; (4) if required 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 32(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.54

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.55 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.56 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.57

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.58 Unconventional fracking refers to the extraction of natural gas from clay, shale, marl and coal formations.59 As opposed to the long-term experience with conventional fracking, there has been no long-term experience with unconventional fracking in Germany so far.60

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.61

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. So far, no test drillings have been approved. However, the German Federal Council has established an independent expert commission that shall issue reports on the test drillings in June 2018. This may be seen as a sign for the first drillings to be approved soon. 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, therefore, remains to be seen when the first test drillings will be carried out 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 of 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. Restrictions and obligations can be imposed on investors from non-EFTA countries if the acquisition of domestic companies endangers public order or security or if

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62 Section 13a(1) No. 2 Federal Water Act.
63 Section 33(1a) Federal Nature Conservation Act.
64 Section 13a(1) No. 1 Federal Water Act.
66 Section 13a(2) Federal Water Act.
68 See, for example, press statement Member of Parliament Julia Verlinden (21 May 2018), available at https://julia-verlinden.de/presse/pressestatements/statements-detail/article/bundesregierung_bereitet_den_weg_fuer_mehr_riskantes_fracking/.
69 Article 49 Treaty on the Functioning of the European Union.
70 An English translation is available at https://www.gesetze-im-internet.de/englisch_awg/englisch_awg.html. Please note that this translation is not binding and may not reflect the latest legislative changes.
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.
there is an actual and sufficiently serious danger to a fundamental interest of society.\textsuperscript{72} 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.\textsuperscript{73}

In July 2017, the German government amended the legislation on foreign investments by amplifying the veto right of the Federal Ministry of Economic Affairs and Energy. The amendment includes 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.\textsuperscript{74} The Ministry already examines acquisitions in which a foreign investor acquires at least 25 per cent of the voting rights in the domestic company.\textsuperscript{75} The legislative amendment now extends and specifies the examination right to specific entities, such as operators of critical infrastructure, which includes the oil and gas sector.\textsuperscript{76} 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. The impact of these sanctions on Germany, especially of those coming into force in November and curbing Iranian energy exports remain to be seen, as negotiations are still ongoing.

\section*{ii Capital, labour and content restrictions}

Freedom of capital movement\textsuperscript{77} and freedom of movement for workers\textsuperscript{78} 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 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.\textsuperscript{79} 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.\textsuperscript{80} The asset reports shall be submitted once a year to the German Central Bank by electronic means.\textsuperscript{81}

\begin{footnotes}
\item[72] Section 5(2) Foreign Trade and Payments Act.
\item[73] Sections 5(4) and 4(1) No. 5 Foreign Trade and Payments Act.
\item[74] Section 55(1) Foreign Trade and Payments Ordinance.
\item[75] Section 56 Foreign Trade and Payments Ordinance.
\item[76] Section 55(1) No. 1 Foreign Trade and Payments Ordinance.
\item[77] Article 63 Treaty on the Functioning of the European Union.
\item[78] Article 45 Treaty on the Functioning of the European Union.
\item[79] Article 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. Please note that this translation is not binding and may not reflect the latest legislative changes.
\item[80] Section 65 Foreign Trade and Payments Ordinance.
\item[81] Sections 71(2) and 72 Foreign Trade and Payments Ordinance.
\end{footnotes}
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. Exceptions from 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.

IX CURRENT DEVELOPMENTS

i Pipelines and LNG

The total length of Germany’s gas pipeline network is about 511,000km. The pipelines import natural gas to Germany and distribute it around the country. The pipeline network is also interconnected to pipelines in other EU countries, and gas is transported across Germany 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 transport 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 the Commission asked the European Council for a mandate to negotiate an agreement with Russia regarding the management of the Nord Stream 2 project. Currently, a legislative proposal to revise the common rules for the internal gas market is under way; this would impact existing and future gas pipelines between the EU and third countries. If adopted, the Nord Stream 2 pipeline would have to fully comply with the revised rules on third-party access, tariff regulation, ownership unbundling and transparency. Derogations and exemptions would be possible, and it remains to be seen whether they could be applicable to the Nord Stream 2 project.

However, despite the controversies surrounding the project and while the EU legislative proposal is moving forward, the construction of the pipeline is progressing on German territory. After having carried out the necessary environmental impact assessment and public hearings, the relevant authorities have granted their approval to construct the pipeline in the first quarter of 2017. Following the approval, preparatory work for the installation of the pipelines in German coastal waters have already begun, and the first pipelines have been laid.

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 70 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. Currently, Germany does not have its own reception terminal for LNG but access to LNG can be secured through Belgium, the Netherlands and other European countries.97 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.98 Furthermore, there are plans for building Germany’s first LNG terminal in northern Germany. The final investment decision is scheduled for 2019, and after a three-year construction phase the terminal is supposed to go online in 2022.99 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’.100 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.101 The volume of usable working gas was 24.4 billion cubic metres in 2017.102 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 capacity could supply Germany for 80 days on average.103 To further ensure a secure gas supply, the total storage volume is supposed to be increased by additional 6 billion cubic metres over the next few years, depending on commercial viability.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 Digitisation

The digital age brings further challenges to the oil and gas industry in Germany. Digitisation of exploration and extraction methods and new automated technologies will continue to change the way how oil and gas fields can be explored and extracted. The optimisation of exploration and extraction, the improvement of cost management as well as enhanced protection of health, safety and the environment will change the future of the oil and gas industry in Germany. Companies already employ new automated technologies, big data analytics or visualising software for more efficient production. It remains to be seen how the legislature will work together with industry stakeholders and other interest groups to develop and establish a legal framework to adapt to the digital change.
Chapter 13

GHANA

Ferdinand Adadzi and Nana Serwah Godson-Amamoo

I INTRODUCTION

i Historic overview

The oil and gas upstream 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 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.

ii Legislative overview

In the mid-1980s, the government introduced new legislative and regulatory reforms. 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 company to champion state activities in the upstream oil and gas sectors. In addition, the now repealed Petroleum (Exploration and Production) Law, 1984 (PNDCL 84) and the Petroleum Income Tax Law 1987 (PNDCL 188) were passed to regulate operations and taxation in the upstream oil and gas sector.

1 Ferdinand Adadzi is a partner and Nana Serwah Godson-Amamoo is an associate partner at AB & David.
2 National Energy Policy (February 2010), Ministry of Energy.
3 ibid.
5 National Energy Policy (February 2010), Ministry of Energy.
6 ibid.
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.’ For the effective control and management of exploitation of these resources, the Constitution requires parliamentary approval for all transactions involving the grant of a right for the exploitation and production of minerals in Ghana and further mandated the establishment of natural resources 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 in 2009, the Petroleum Commission Act, 2011 (Act 821) was subsequently passed to set up the Petroleum Commission as a regulator to coordinate activities in the upstream petroleum industry in accordance with the Constitution. 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 has enacted a number of regulations, guidelines and developed policies for the sector. These include the following:

a. the 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;

ej. Guidelines for the formation of joint venture companies in the upstream petroleum industry of Ghana (March 2016); and

k. the Oil and Gas Insurance Placement for the Upstream Sector.

### Industry and foreign investment overview

The establishment of the state oil and gas 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 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. In addition, the country has adopted
a model petroleum agreement based on international best practice to attract IOCs. The IOCs that have been attracted to the upstream oil and gas sector include Kosmos Energy, Hess Corporation, Tullow UK, Norsk Hydro Oil, Heliconia Energy Resources, Anadarko, ENI, Aker Energy 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 and is 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), 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), 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 lead exploration company. The field has proven reserves of approximately 3 billion barrels9 and is currently estimated to be producing approximately 110,000 barrels of oil per day.10


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 800 km², was approved by the government. Production has commenced from the TEN fields, and the first oil was delivered to the FPSO 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

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7 ibid.
8 Ghana Gazette, No. 5, 2014.
Nyame oilfields through the FPSO John Agyekum Kufuor in July 2017.\textsuperscript{11} Gas production commenced in June 2018, and the field is expected to produce 180 million cubic feet of gas per day for 15 years.\textsuperscript{12}

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 and PN-1 (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. Therefore, GNPC is currently the sole shareholder of GGCL and national aggregator of gas. It is estimated that Ghana has approximately 22.65 billion cubic metres of proved reserves of natural gas in its oil fields.\textsuperscript{13} 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.\textsuperscript{14} 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.

II LEGAL AND REGULATORY FRAMEWORK

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. As noted earlier, the primary law governing the upstream oil and gas sectors are the Petroleum (Exploration and Production) Act, 2016 (Act 919) 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.\textsuperscript{15}

Owing to increased activities in the upstream oil and gas sector after the commercial discoveries in the deepwaters, various regulatory reforms were initiated. This has resulted in the enactment of the Petroleum Commission Act 2011 (Act 821), the E&P Act and

\begin{itemize}
\item \textsuperscript{11} ibid.
\item \textsuperscript{12} https://www.eni.com/en_IT/operations/upstream/exploration-model/octp-ghana.page.
\item \textsuperscript{13} https://www.cia.gov/library/publications/the-world-factbook/geos/gh.html.
\item \textsuperscript{14} www.myjoyonline.com/business/2014/September-3rd/president-mahama-atuabo-gas-project-will-be-game-changer.php.
\item \textsuperscript{15} Income Tax (Amendment) Act, 2016 (Act 907).
\end{itemize}
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, its dual capacity created conflict that 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 GNPC 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:

a. the power of the Minister to open an area for petroleum activities;

b. the power of the Minister to close an area or redefine the boundaries;

c. that petroleum agreements must be entered into in accordance with an open, transparent and competitive public tender process;

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;

e. the right to review terms and conditions of the petroleum agreement owing to material change in circumstances;

f. the right of the Minister to approve an operator before the execution of a petroleum agreement;

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;

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);

i. the right of a contractor to submit a proposal to relinquish a contract area or part of a contract area;

j. the minimum work and expenditure obligations to be fulfilled by the contractor during the initial exploration period;

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;

l. the requirement of a permit for exploration drilling and an annual permit for the production of petroleum;

m. the requirement of a licence to install and operate facilities for the transportation, treatment and storage of petroleum;

n. the establishment of a petroleum register for petroleum agreements, licences, permits and authorisations;

o. the right of the Minister to require a licensee, contractor or sub-contractor to provide security for the fulfilment of its obligations under an agreement;

p. the establishment of a local content fund;

q. pollution damage, liability of the polluter;

r. payment of income tax in accordance with the laws of Ghana except as modified in the agreement;

s. payment of royalties; and

t. payment of a bonus to Ghana.
The Act also prescribed specific terms that must be provided in the petroleum agreements. These include:

- **a** the right of GNPC to hold an initial participating carried interest of at least 15 per cent for exploration and development;
- **b** the GNPC has the option to acquire an additional participating interest as determined in the petroleum agreement within a specified period of time;
- **c** the petroleum agreement must be for a term not exceeding 25 years subject to ability of the Minister to extend;
- **d** change of ownership of contracting party is subject to consent of the Minister or Commission; and
- **e** the GNPC has the pre-emptive right to acquire interest of contractors.

The general requirements for petroleum activities under the Act include:

- **a** the standard of operations in conducting petroleum activities;
- **b** supervision and inspection;
- **c** data and information obtained by a licensee, contractor or subcontractor as a result of petroleum activities are property of Ghana;
- **d** maintaining records of data and information in Ghana;
- **e** provision of information upon request by the Minister;
- **f** the use of Ghanaian goods and services; and
- **g** the local content plan.

**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’. Essentially, the Act establishes the Petroleum Commission to perform the regulatory functions previously performed by the GNPC under the PNDCL 84.

**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’. 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. The Regulations provide minimum thresholds for indigenous equity participation in petroleum activities.

A key provision under the Regulations is the requirement of 5 per cent indigenous participation in petroleum agreements. 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. 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. 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. 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.

**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. It also indicates that the initial participating interest in relation to exploration and development shall be a carried interest, and in the case of production operations, an additional participation interest. Other relevant provisions include the procedure for licensing and the criteria for grant of licences, change of ownership and operating standards under a petroleum agreement.

**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.

**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.

**The Petroleum Revenue Management Act, 2011 (Act 815) as amended**

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, the Ghana Stabilisation Fund and the Ghana Heritage Fund – and indicates how revenues accruing from petroleum operations to the state

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16 The Petroleum Revenue (Amendment) Act 2015 (Act 839).
are to be disbursed and utilised. All the funds created under the Act are public funds and may not be encumbered, used to provide credit or collateral for the state or private entities. The Act also prohibits borrowing against petroleum reserves.

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, the establishment of the Investment Advisory Committee and other related matters.

**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.

**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.

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**ii Regulation**

**Government of Ghana (through the Ministry of Energy)**

The 1992 Constitution vests all petroleum resources in the president of Ghana as the head of the executive branch of government. 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. 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.

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).
Parliament

The 1992 Constitution requires all petroleum agreements to be ratified by Parliament. Parliament may also exempt particular transactions or agreements from ratification. Such exemptions must be supported by the resolution of at least 75 per cent of the members of Parliament.

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:

- promoting planned, well-executed, sustainable and cost-efficient petroleum activities;
- recommending to the Minister national policies on petroleum activities;
- monitoring compliance with national policies, laws, regulations and agreements;
- complying with health, safety and environmental standards in petroleum activities;
- promoting local content and local participation in petroleum activities; and
- receiving applications and issuing permits for specific petroleum activities.

Treaties

Ghana became a signatory to the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (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.

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.

III LICENSING

Under its former regulatory mandate, the GNPC conducted comprehensive studies and evaluations of the overall oil and gas potential of the sedimentary basins of Ghana. Based on these evaluations, the Ministry of Energy has packaged the potential into oil blocks over which rights may be granted to prospective contractors for exploration and production under a petroleum agreement.

Any person intending to engage in petroleum exploration and development must commence the process by submitting an application to the Minister. Although Act 919 favours the award of petroleum rights through competitive bidding, this option is yet to
be implemented by the Ministry. In April 2018, the government launched the processes leading to the first ever oil and gas licensing round, which is expected to be concluded by early 2019 with negotiations and award of licences. This announcement was followed with the inauguration of the Licensing Bid Rounds and Negotiation committee to supervise the open tender processes.

To date, however, all petroleum rights granted in Ghana have been through direct negotiation with prospective contractors. Applications are referred to the Petroleum Commission for evaluation and due diligence on the applicant. Applicants are evaluated on their financial capability, technical track record, proposed work programme and budget, and proposed fiscal package. The due diligence will inquire into the corporate status of the applicant, the competence of the management and technical team of the applicant and overall, its capacity to conduct the petroleum operations. On the basis of this evaluation, a recommendation is submitted to the Minister. If an applicant is qualified, the Minister will constitute a petroleum agreement negotiation team comprising senior officials from the Ministry of Energy, the GNPC, the Attorney-General’s Department and the Ghana Revenue Authority.

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.

The Ministry of Energy has developed the Model Petroleum Agreement (MPA), which is the basis of negotiations with prospective contractors. The terms 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;
- 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. This restriction applies to both contractors and subcontractors. 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. 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.

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. Income tax is assessed at 35 per cent of the chargeable income or as provided in the taxpayer’s petroleum agreement. The prevailing rate in recent petroleum agreements is 35 per cent.

Income tax is calculated net of all expenses that are incurred in the petroleum operations. 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. Expenses that are not allowed are stated under the Act.

Employees of petroleum operators are subject to income tax at varying rates depending on their nationality and income. Petroleum agreements may provide some exemptions for foreign employees working in Ghana for periods under 30 days. Other taxes that are typically exempted under petroleum agreements are value added tax (VAT), customs and import duties and taxes associated with importation of equipment for petroleum operations.

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 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.


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.

iii 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 to issue permits for operation, location and movement of mobile offshore drilling equipment. Other activities the 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.

The GMA is also the implementing agency of Ghana’s obligations as a member of the International Maritime Organization (IMO). 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).

VIII FOREIGN INVESTMENT CONSIDERATIONS
i Establishment
Under the E&P Act, a contractor in a petroleum agreement is required to be incorporated in Ghana. 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. A branch of a foreign entity cannot be a party to a petroleum agreement. 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.

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;
- 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;
- c 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;
- d 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;
- e an employment and training sub-plan;
- f a research and development sub-plan;
- g a technology transfer sub-plan;
- h a legal services sub-plan; and
- i 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 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.

Currently, a key concern in respect of transparency is the process of the award of petroleum rights. To resolve this, the government this year has made a commitment to launch a public tender of at least three new oil blocks in accordance with requirements under the E&P Act. The law further provides for the establishment of a public register of all petroleum agreements; however, a register is yet to be set up for this purpose. 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 on Combating Bribery of Foreign Public Officials in International Business Transactions, the United States of America Foreign Corrupt Practices Act 1977 and the United Kingdom Bribery Act 2010.

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 fourth quarter of 2021.

ii Recent licensing rounds

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). 5 per cent interest is expected to be granted to a Ghanaian company to be identified by ExxonMobil and the government.

The Ministry has recently announced plans to award licences for nine new oil blocks in the Western Basin. Six of the blocks are planned to be awarded this year, while the remaining three shall be awarded in 2019. Of the six blocks slated for 2018, three are planned to be allocated through open public competitive tender, two through direct negotiations and one shall be reserved for GNPC to explore in partnership with its chosen strategic partner.

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.

iv 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.
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 is open for applications until 31 December 2018. Currently, one licensing round is being conducted for the Davis Strait, while a licensing round for Baffin Bay ended in December 2017 without any bids.

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 Grønland and Greenland Gas and Oil. However, during the last year, several of the major players have surrendered some or all of their licences.

1 Michael Meyer is a partner at Gorrissen Federspiel. The author is grateful to his colleagues, attorney Lars Fogh for his contribution to the section on tax, and 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, ConocoPhillips, 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 Act3 (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 fall of 2016 with, among others, changes to and improvements of the rules on small-scale mineral licences, which are becoming increasingly popular.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 (MMR); however the responsibility for social aspects (e.g., SIA) remains with the Ministry of Labour, Industry and Trade (MILT). Environmental aspects are handled by the Environmental Agency for Mineral Resources Activities (EAMRA) and the day-to-day aspects of the industry as well as licence applications are handled by the Mineral Licence and Safety Authority (MLSA). The Department of Geology under the MMR is responsible for geological matters. In general, licences for hydrocarbons are granted by the government.5

3 Inatsisartut Act No. 7 of 7 December 2009 with subsequent amendments.
4 Act No. 34 of 28 November 2016. The amendment entered into force on 1 January 2017 and introduced, inter alia, the possibility to grant a small-scale licence for areas otherwise subject to exclusivity rights provided, however, that the exclusivity rights holder consents hereto.
5 For more information, see www.govmin.gl.
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 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’. Such 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 is 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.

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 plus a surcharge of 6 per cent of the tax paid for the income year of 2018. 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 of 6 per cent, 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.

If a company transfers a part of or its entire prospecting or exploration licence, the Act on Income Taxes states that the seller of the licence is not obligated to include the consideration in the taxable income if the seller receives payment in a form where the buyer undertakes the prospecting or exploration expenses. To apply this rule, the selling company must meet certain requirements and if these requirements are met, including that all expenses are deductible as operating expenses for the company bearing the expense, the consideration will not be subject to taxation.

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 MILT.

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 damages.

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 such risks to the extent possible. The authorities will set up an emergency committee with the task of coordinating the actions of the authorities in case 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 such 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 such 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 such 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 MMR introduced its zero tolerance policy on corruption. In accordance with international recommendations, the MMR 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 MMR 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 is currently conducting 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 is still open for applications until 31 December 2018. These mark the final stage of the 2014–2018 Oil and Mineral Strategy, which the government has decided to see through, although expectations for bids are low. Accordingly, the last finalised licensing round for Baffin Bay finished on 15 December 2017 with no applications. At the time of writing, this leaves the total number of active hydrocarbon licences at 18 down from 29 last summer (with companies such as Cairn, Shell and Maersk handing in licences). No information has been published on initiatives for a new oil strategy by the recently formed government after the election in April 2018. Meanwhile, news on positive exploration outcomes remains scarce.

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. It remains to be seen if any further licences will be issued, and 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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8 Inatsisartut Act No. 5 of 19 May 2010.
9 According to the list of exploration and exploitation licenses (exclusive) in force and prospecting licences (non-exclusive) in force published by the MLSA, last released 2 July 2018, available at www.govmin.gl.
Chapter 15

INDIA

Venkatesh Raman Prasad

I INTRODUCTION

India is the third-largest energy consumer in the world, and oil and gas, as an energy resource, contributes to 42 per cent of its total energy mix. As of March 2017, the country had balance recoverable reserves of about 604 million metric tonnes of crude oil and about 1,183 million metric tonnes of natural gas. The average oil and gas production of the country is about 611.94 million standard cubic feet per day. With this level of production, about 82 per cent of the crude oil and about 44 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.

At present, 17 blocks under nomination regime are being operated by OIL and ONGC.

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1 Venkatesh Raman Prasad is a partner at J Sagar Associates.
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. Out of these, 12 blocks are operational at present.\(^8\)

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, 26 blocks are operational.\(^9\)

NELP regime (for blocks awarded between 1997 and 2010)

The new exploration licensing policy (NELP) was implemented from 1999.\(^10\)

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, 73 are operational.\(^11\)

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.\(^12\)

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).\(^13\)

The key features of HELP include:

- uniform license 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.;
- 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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\(^8\) DGH Report, page 27.
\(^9\) DGH Report, page 27.
\(^12\) 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 proposed (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.

The first bidding round under HELP was launched in 2017 wherein 55 blocks were bidded out.

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.\textsuperscript{14}

It may be noted that one of the significant change 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)\textsuperscript{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.\textsuperscript{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.\textsuperscript{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.


\textsuperscript{17} ‘Cabinet approves Policy Framework for exploration and exploitation of Unconventional Hydrocarbons’, Press Information Bureau, Government of India, Cabinet, (1 August 2018, 06:10 PM), http://pib.nic.in/newsite/PrintRelease.aspx?relid=181361.
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 a recent 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 new 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 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.

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.
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 MoPNG: Pursuant to its resolution dated April 8, 1993, the MoPNG established the Directorate General of Hydrocarbons (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 Petroleum 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.

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.

24 Notification No. SO 1502(E), Ministry of Petroleum and Natural Gas, Government of India (8 June 2008).
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.

However, it can be noted that as a method of dispute resolution, the Model RSC under the HELP OALP Round-1 only incorporates provision for domestic *ad hoc* arbitration.25

**India’s bilateral investment treaties**

Since 1994, India has entered into 83 bilateral investment treaties (BITs).26 In December 2015, India adopted a revised model text for its BITs.27 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 April 2017.28 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. As per information in the public domain, while Bangladesh and Colombia have signed or approved the signing of the joint interpretative statement, the status with respect to the other countries is unclear.29

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25 *Ad hoc* arbitration is arbitration agreed to and arranged by the parties themselves without recourse to any institution.


28 The exact date of termination of the aforementioned 58 BITs is not clear as no official statement has been issued by the GoI in that regard. However, as per the information available in public domain, the BITs were terminated on 31 March 2017, ‘India to trade partners: Sign new bilateral investment treaties by 31 March’, https://www.thehindubusinessline.com/economy/indias-bilateral-investment-pacts-under-cloud/article9625580.ece.

According to the United Nations Conference on Trade and Development (UNCTAD), which keeps an account of the number of investment disputes, a total of 29 known investor–state dispute settlement cases are pending against India. Further, there are five cases where India is the claimant.30

**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 and Singapore to remove the exemption on capital gains tax on payable on sale of shares of an Indian company after 1 April 2017.31

**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) would be further 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.32 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.33

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.34

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32 PNG Rules, Rule 7(i).
33 PNG Rules, Rule 7(ii).
34 PNG Rules, Rule 5.
Continental Shelf, Exclusive Economic Zone and Other Maritime Zones Act, 1976 provides for the granting of licences by the Indian government to explore and exploit the resources of the continental shelf and exclusive economic zone.35

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.36 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

36 PNG Rules, Rule 27.
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.

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.\(^{37}\) 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).\(^{38}\) 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.\(^{39}\)

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.\(^{40}\)

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.

ii Goods and Services Tax (GST)

GST, a single tax on the supply of goods and services, formulates the new indirect tax regime applicable in India from 1 July 2017. Under the new regime, credits of input taxes are

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\(^{37}\) PNG Rules, Rule 17.

\(^{38}\) Model RSC, Ministry of Petroleum and Natural Gas (2017), Article 26.3.


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 liquified 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.\(^{41}\)

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.\(^{42}\) 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.\(^{43}\)

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.

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 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).\(^ {44}\)

Deduction is allowed for any capital expenditure incurred for ‘laying and operating a cross-country natural gas or crude or petroleum oil pipeline network for distribution, including storage facilities being an integral part of such network’\(^ {45}\)

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\(^{43}\) ‘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.cee.

\(^{44}\) Section 42 of the IT Act.

\(^{45}\) Section 35AD of the IT Act.
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:

a. 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;

b. 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

c. 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:

a. 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;

b. 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

c. 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.

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

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46 Section 32(iiia) of the IT Act.
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. 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. 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.

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. 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. 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.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

As per the Foreign Direct Investment Policy (FDI Policy), read with The Foreign Exchange Management Act, 1999 (FEMA) and the Foreign Exchange Management (Transfer or Issue of a Security by a Person Resident Outside India) Regulations, 2017, 100 per cent foreign 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

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47 PNG Rules, Rule 22(1).
48 PNG Rules, Rule 22(2).
49 PNG Rules, Rule 22(3).
51 Model RSC, Ministry of Petroleum and Natural Gas (2017), Article 4.4.
52 Site Restoration and Abandonment Guidelines for Petroleum Operations (April 2018).
53 ‘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.
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 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.\(^{54}\) 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 recent 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.\(^{55}\) 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 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

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\(^{54}\) 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.

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.\textsuperscript{56} 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, \textit{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, 55 blocks were offered on a competitive bidding basis under OALP Bid Round-I. Out of the 55 blocks, 41 blocks have been awarded to Vedanta Limited, nine blocks to OIL, two blocks to ONGC and one block each to Bharat PetroResources Limited, Hindustan Oil Exploration Company Limited and GAIL Limited.\textsuperscript{57} No foreign player had submitted its bid for this round.

Additionally, the Discovered Small Fields Bid Round, 2016, has recently 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 this year has put on offer 59 unmonetised discoveries clubbed into 25 contract areas under Discovered Small Fields Bid Round-II, 2018.\textsuperscript{58}

In relation to policy formulation to enhance domestic production, the Indian government has recently, approved the policy to permit exploration and exploitation of unconventional hydrocarbons, such as shale oil and gas and CBM, under the existing PSCs, CBM contracts and nomination fields. This move would encourage the existing contractors in the licensed or leased area to explore options of unconventional hydrocarbons in the existing acreages.\textsuperscript{59}

The Indian government has also approved the policy framework for streamlining the operations of PSCs, which, \textit{inter alia}, provides for special dispensation for difficult areas,

\textsuperscript{56} Section 3 of the PML Act.
\textsuperscript{57} ‘List of awardees under OALP Bid Round-I’, http://dghindia.gov.in/assets/downloads/5b84f4d0b6c0List_of_Awardees_under_OALP_Bid_Round.pdf.
\textsuperscript{58} ‘Discovered Small Fields’, official website, http://online.dghindia.org/dsf2/.
extension tax benefits to Pre-NELP blocks and sharing of statutory payments between contractors in proportion to their participating interests in the Pre-NELP exploration blocks.60

Recently, the consortium constituting Reliance Industries Limited (RIL), BP Plc and Niko Resources Limited won an arbitral award against the government in the KG D6 gas migration dispute. The case pertained to the Indian government’s claim of a US$1.55 billion penalty against RIL and its partners, BP Plc and Niko Resources Limited, for allegedly syphoning gas from state-owned ONGC’s block. An international arbitration tribunal rejected the government’s claim and held that the consortium was entitled to produce all gas from its block.61


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 who 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.

LEGAL AND REGULATORY FRAMEWORK

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 which 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.

1 Christopher B Strong is a partner at Vinson & Elkins LLP. The information in this chapter is accurate as of November 2017.
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;
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:

a. 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 is 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 or 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 last 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:

a. contracts for the exploration, development and production of exploration blocks and oil and gas fields (i.e., TSCs);

b. seismic survey contracts;

c. contracts for the drilling of wells;

d. contracts for the reclamation of wells;

e. contracts for well services including casing, cementing, stimulation, electrical logging and completion;

f. contracts for surface installations of oil and gas extraction and production operations;

g. contracts for water injection facilities;

h. contracts for flow pipes;

i. contracts for gas treatment facilities;

j. contracts for cathodic protection;

k. contracts for engineering surveys and quality control;

l. contracts for the drilling of water wells; and

m. 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.
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 proposed 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. We will see whether progress is made on this front in 2018.

ii Case study – the Basrah Gas Project

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.
Chapter 17

IRAQI KURDISTAN

Florian Amereller and Dahlia Zamel

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 177 trillion cubic metres of 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 550,000 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 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.

1 Florian Amereller is a partner and Dahlia Zamel is a senior associate at Amereller Legal Consultants.
2 The estimates of the MNR include unproved resources and exploration potential. Several IOCs active in the KRI had to downgrade their reserves because of geological problems.
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 earlier this year focusing on developing the gas sector in the KRI, including a new gas pipeline.

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 very 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 Iraq, which then diverted outputs to local refineries. The central government and the KRG are currently in talks over Kirkuk exports. It still remains to be seen whether the various parties involved, in particular the KRG and the central government, but also the inner Kurdish participants, can find a mutually acceptable solution to bring peace and prosperity to the whole of Iraq or whether the ongoing disputes will finally be settled by the Federal Supreme Court of Iraq, the country’s independent judicial body that interprets the Constitution and determines the constitutionality of laws and regulations.

In 2012, the central government filed a case against the KRG challenging the latter’s independent oil exports. The case, had until recently, been continuously postponed owing to a procedural loophole that prevented the court from the hearing the case without the attendance of a KRG representative. This finally changed in April 2018 when the KRG attended at the court. Since then, the court has requested the submission of documents by the parties and resolved on the appointment of an expert to provide a report on the technical and other aspects of the case. The appointment of such an expert has been difficult with the KRG objecting to the first appointed expert on the basis of objectivity and the court accepting the objection and rescinding the appointment. After several attempts at appointing a suitable expert, the Federal Supreme Court finally decided that it requires a three-person expert committee including nominees from the Iraqi Geologists Union, the Iraqi Engineering Union and the Iraqi Economists Union. The three persons constituting the expert committee were named and sworn in on 9 October 2018. The next hearing is scheduled for 6 November 2018. Experts appointed by Iraqi courts often take months and even years to provide their final report and recommendations.
To further add to the instability of the once stable KRI, Masoud Barzani, the former president of the KRI announced his resignation on 29 October 2017, leaving a void in his wake. In the interim, his functions are distributed amongst the parliament, the council of ministries and the Judicial Board. Amidst internal conflict between the different Kurdish political parties resulting from many factors, including the independence referendum, the president’s resignation, 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.

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’.\(^3\) 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.’\(^4\)

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’. This said, the KRG maintains that present fields within the meaning of the Iraqi Constitution refers only to such 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 refutes 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,

\(^3\) Article 111 Iraqi Constitution.
\(^4\) Article 112(1) Iraqi Constitution.
the INOC Law is far from a federal oil and gas law as envisioned by the constitution 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, and to date the Federal Supreme Court has not yet issued a decision on the matter.

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.

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 government 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.

Premised on the foregoing, in 2007 the KRI legislator passed its own Kurdistan Oil and Gas Law – No. 26/2007 (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. 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 installation) to third parties 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 cabinet identified in Section II.i). The MNR shall encourage public and private sector investment in petroleum operations.

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5 Article 115 Iraqi Constitution.
6 Article 121(2) Iraqi Constitution.
7 Article 2 KOGL.
8 Article 1 No. 18 KOGL.
9 Article 3(4) KOGL.
10 Article 4 KOGL.
11 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. It is unclear how the promulgation of the INOC Law will affect the central governments’ position since the INOC Law permits INOC to also sell hydrocarbons and to remit profits to the state treasury, not the DFI. 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 that the INOC Law is applicable in the KRI.

The central government has initiated several legal proceedings against entities involved in the independent export and sale of oil produced in the KRI, including the state-owned Turkish 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 (KOG Fund) to be managed by a board appointed by the KRG Council of Ministers after an absolute majority approval of the parliament. 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 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.

Section 5(4)(a) CPA 95.

Article 15 KOGL.
ii  Regulation

The regulatory agencies competent for overseeing upstream oil and gas activities in the Kurdistan region are:

\(a\) the Iraqi Kurdistan parliament: the Kurdistan 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;\(^\text{14}\) it mainly formulates the general principles of petroleum policy, prospect planning and field development and approves petroleum contracts;\(^\text{15}\) and

\(d\) the Ministry of Natural Resources of the Kurdistan Region: the MNR oversees and regulates all petroleum operations in the KRI\(^\text{16}\) 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.\(^\text{17}\)

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 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.\(^\text{18}\) Nonetheless, judgments made

\(^\text{14}\) Article 4 KOGL.
\(^\text{15}\) Article 24(1) KOGL.
\(^\text{16}\) Article 6(1) KOGL.
\(^\text{17}\) Article 107(1) Iraqi Constitution.
\(^\text{18}\) Article 25(b) Riyadh Convention.
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.\textsuperscript{19} The same applies to awards of arbitrators.\textsuperscript{20}

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, 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.\textsuperscript{21} 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.\textsuperscript{22}

Key features of the PSC are to be negotiated with the MNR based on the Model PSC published by the KRG,\textsuperscript{23} which includes that:

\begin{enumerate}
  \item a signature bonus\textsuperscript{24} and a capacity-building bonus\textsuperscript{25} are payable by the contractor once the PSC becomes effective;
  \item 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.\textsuperscript{26} 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;\textsuperscript{27}
  \item 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
\end{enumerate}

\textsuperscript{19} Article 25(c) Riyadh Convention.
\textsuperscript{20} Article 37 Riyadh Convention.
\textsuperscript{21} Article 26 KOGL.
\textsuperscript{22} Article 24 KOGL.
\textsuperscript{23} The Model PSC is available at www.krg.org/pdf/3_krg_model_psc.pdf.
\textsuperscript{24} Article 32.1 Model PSC.
\textsuperscript{25} Article 32.2 Model PSC.
\textsuperscript{26} Article 4.1 Model PSC.
\textsuperscript{27} Article 4.3 Model PSC.
two years) and may be extended for a further two years.\textsuperscript{28} Upon commercial discovery, the development period extends to 20 years with two possible extension periods of five years each;\textsuperscript{29}
d preference is to be given by the IOC to local employment,\textsuperscript{30} subcontractors\textsuperscript{31} 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{32}
f during the exploration period, an annual surface rent of US$10 per square kilometre is payable. However, such exploration rental is, as it constitutes petroleum costs, recoverable.\textsuperscript{33} 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{34}
g in the event of a commercial discovery, a production bonus is payable\textsuperscript{35} in addition to a recurring royalty (i.e., a portion of petroleum produced).\textsuperscript{36} 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{37} 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{38} and
i during the exploration period, the contractor may terminate the PSC at the end of each contract year.\textsuperscript{39} Once the development period has been entered into, the contractor has the right to terminate the PSC at any time.\textsuperscript{40}

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{28} Article 6.2 Model PSC.
\textsuperscript{29} Article 6.10 and 6.12 Model PSC.
\textsuperscript{30} Article 23.1 Model PSC.
\textsuperscript{31} Article 22.2 Model PSC.
\textsuperscript{32} Article 23.7 Model PSC.
\textsuperscript{33} Article 6.3 Model PSC.
\textsuperscript{34} Article 7.1 Model PSC.
\textsuperscript{35} Article 32.3 and 32.4 Model PSC.
\textsuperscript{36} Article 24.1 Model PSC.
\textsuperscript{37} Article 25.3 and 25.4 Model PSC.
\textsuperscript{38} Article 26 Model PSC.
\textsuperscript{39} Article 45.3 and 7.4 Model PSC.
\textsuperscript{40} 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.41

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.42

In practice, and based on the Model PSC published by the MNR, PSCs always 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.43 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.44

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41 Article 16.15 Model PSC.
42 Article 30 KOGL.
43 Article 39.2 Model PSC.
44 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. Such 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’. ⁴⁵

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  TAX ⁴⁶

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. ⁴⁷

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.

i  Rights and obligations of the contractor entities

These include the following.

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⁴⁵ Article 39.4 and 39.6 Model PSC.
⁴⁶ 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.
⁴⁷ Article 40 KOGL.
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 moveable capital, any taxes on capital gains, and any fixed taxes on transfers.48

The IOC is exempt from any withholding tax, surface tax, windfall tax and additional profits tax as provided in Article 44 KOGL.49

The IOC is subject to corporate income tax on its income from petroleum operations.50 Payment of such income tax shall be made by the KRG throughout the entire duration of the contract.

The IOC must provide appropriate tax returns in accordance with applicable law together with a calculation of the amount of income tax due.51

Each contracting entity shall pay or withhold the personal income tax and social security contributions with respect to its employees.52

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 the earn in the KRI.

Obligations of the government

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.55

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.54

According to the Iraqi Constitution no tax may be imposed nor an exemption made except pursuant to a law.55 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 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.

48 Article 31.1 Model PSC.
49 Article 31.4 to 31.7 Model PSC.
50 Article 31.2 Model PSC.
51 Article 31.2 Model PSC.
52 Article 31.8 Model PSC.
53 Article 31.1 Model PSC.
54 Article 31.2 Model PSC.
55 Article 28(1) Iraqi Constitution.
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.\(^{56}\) IOCs are also required to make payments towards an Environment Fund.\(^{57}\)

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 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.\(^{58}\) 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 such damages.

As regards environmental requirements in connection with decommissioning, the IOC must present a decommissioning plan to the management committee at least 24 months before the estimated date of the end of commercial production including environmental

\(^{56}\) Article 37.1 Model PSC.

\(^{57}\) Article 37(1)(10) KOGL and Article 23.8 Model PSC.

\(^{58}\) Article 42 KRG Environment Law No. 2/2008.
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.\(^5\)

**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.\(^6\) The term ‘office’ as used does not specify whether such ‘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:

- corporate documents of the IOC (certificate of establishment, commercial register extract, statutes, etc.);
- 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;
- power of attorney granted to the person to be appointed manager of the branch plus a copy of his or her passport;
- evidence of the business premises in KRI; and
- 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)\(^6\) or a decision by the MNR approving such 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 from 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.

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\(^6\) and to pay any subcontractor and its expatriate personnel in foreign currency.\(^6\)

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\(^5\) Article 38.1 Model PSC.
\(^6\) Article 46 KOGL.
\(^6\) https://www.mnronline.com/Online/Registration/
\(^6\) Article 29.4 Model PSC.
\(^6\) Article 29.9 Model PSC.
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, such 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. Such 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 been investigating government actions and government projects in particular in the 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.

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64 Article 44(1) KOGL and 23.1 Model PSC.
65 Article 45 KOGL and 23.4 Model PSC.
66 Article 45 KOGL.
67 Article 23.2 Model PSC.
68 Article 23.3.1 Model PSC.
69 Article 23.3 Model PSC.
70 Article 44(2) KOGL.
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 (recently threatened by IS) has been outstanding in comparison with central Iraq and had a vastly positive effect on the 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 recent success of the Peshmerga and Iraqi forces against ISIS in northern Iraq will undoubtedly return some of the confidence which may have diminished over the last few years because of the presence of IS.

On the other hand, the lack of a working infrastructure to independently transport hydrocarbons out of the KRI 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 had 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.

Iraq has been in talks with the KRG and Turkey to resume Kirkuk oil exports through Ceyhan. The KRG is heavily in debt. The central government took some steps to ease tensions earlier this 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 dropped the KRG’s allocation to 12.67 per cent, continuing the bitter dispute over the KRG’s share in revenues.
Chapter 18

MEXICO

José Antonio Postigo-Uribe, Guillermo Villaseñor-Tadeo and Tania Elizabeth Trejo-Galvez

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 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.
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).

### 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 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.

### iii 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 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.

Regarding tax information exchange agreements, Mexico is a contracting party to the Convention on Mutual Administrative Assistance in Tax Matters between the Council of Europe and the (Organisation for Economic Co-operation and Development) OECD, and its Modification Protocol of 27 May 2010, which is in force under the Decree published in the Federal Official Gazette on 27 August 2012.

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 prequalification 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 such 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
(COFEC), 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
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.
Round One was structured in four bids and comprised five production sharing agreements and 33 licence-type agreements. According to the CNH, during Round 1, 39 areas of 55 tendered were awarded, an adjudication percentage equivalent to 70 per cent. These new contracts will be operated by 49 companies from 14 different countries.

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, 65 per cent of the blocks offered were awarded, that is, 19 of the 29 offered.

Finally, Round Three is currently constitutes three bids. In the first bid, 16 of the 35 contractual areas offered were awarded. In addition, the CNH approved amendments to the bid rules of the second bid of Round Three for the award of 37 licence contracts for exploration and extraction of hydrocarbons in conventional onshore deposits. With these modifications, the CNH postponed the opening of proposals for two months to tie it with the third bid of Round Three. Therefore, the presentation and opening of proposals for both bids will take place on 14 February 2019.

In light of the above, the SENER, jointly with the CNH, is analysing a substantial increase in the number of areas and blocks offered in future oil bid rounds, which will increase national production of oil and gas, as well as reserves in the medium term. In addition, this measure aims for Mexican consolidation as one of the most attractive investment destinations in the world in terms of hydrocarbons.
Chapter 19

NEW ZEALAND

Paul Foley

I INTRODUCTION

i Overview

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.

Oil

In 2018, oil prices 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.

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Gas

Gas use for power generation was up 45.2 per cent from the December 2017 to the March 2018 quarter, with overall gas supply up 6.4 per cent. Production of gas is dominated by the Pohokura and Maui fields, which are responsible for over half of New Zealand’s domestic gas production.6

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.

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. The new government announced that it would not issue new permits for offshore oil or gas exploration, meaning that future block offers would be restricted to onshore locations.

This decision was stated to 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.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 intends to introduce a Zero Carbon Bill that will encapsulate these goals to Parliament later this year.

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

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 In 2018, the Block Offers will be limited to areas within onshore Taranaki region.
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.

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.

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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;

c 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;

d Crown Minerals (Petroleum Fees) Regulations 2016, which outline the fees payable for petroleum under the CMA;

e Crown Minerals (Royalties for Minerals Other than Petroleum) Regulations 2013, which cover royalties and royalty reports on mining permits;

f 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

g 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 \textit{ad valorem} royalty or an accounting profit royalty, whichever is greater in any given year. The royalty rates are either:

a 5 per cent \textit{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.\textsuperscript{13}

\textbf{ii 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.

\textsuperscript{13} Crown Minerals (Royalties for Petroleum) Regulations 2013, Regulation 14.
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.

LICENSING

Overview

The main instruments required to undertake petroleum activities in New Zealand are:

- a permit under the CMA;
- the required consents under the RMA or the EEZCSA; and
- 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.14

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.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.16 They are granted for a maximum four-year period, with no right of extension.

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).17 The geographical scope of future block offers has been substantially reduced by the government’s decision to stop offshore block offers altogether and for 2018 to limit onshore block offers to acreage in the Taranaki region. See more discussion of government policy in Section I.

16 Minerals Programme for Petroleum 2013, at 4.2.3 and 6.2.5.
17 Minerals Programme for Petroleum 2013 at 7.2.
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.\(^{18}\) 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 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

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18 Minerals Programme for Petroleum 2013, at 7.2.3.
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.
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.

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. 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.

There is a Crown Minerals Amendment Bill before Parliament which, if passed, would extend the grounds for revocation of tier 1 permits. Under this Bill, a tier 1 permit would be able to be revoked if a change of control of a permit holder occurs without the prior consent of the relevant minister.

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. The permit holder must enter into an access arrangement with the land owner before it can commence prospecting, exploration or mining. 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.

Access to minerals on Crown-owned land has special challenges, particularly when the land is administered by the Department of Conservation (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. 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.

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.34 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.35

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, infra.

V ASSIGNMENTS OF INTERESTS

i 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. However, under the Crown Minerals Amendment Bill currently before Parliament, this position may change in relation to applications for consent to a change of control of a tier 1 permit holder. Under this Bill, applications for consent to a change of control of a tier 1 permit holder would need 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 would provide grounds for the relevant minister to revoke the permit of the relevant operator.36

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 below 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, 17 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 weighs 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 early 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 new 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 2020.
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 through 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.\(^{37}\)

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.\(^{38}\) 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.

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\(^{38}\) Overseas Investment Act 2005, Section 12 and Schedule 1.
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.39

v  Anti-corruption
New Zealand has a reputation for being a country with a transparent system of government and low levels of corruption. In 2016, New Zealand was ranked number one as the least corrupt country, equal to Denmark, in Transparency International’s corruption perceptions index.

Bribery and corruption are offences in relation to both the private sector40 and the public sector.41 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
i  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.

40  Secret Commissions Act 1910.
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.

ii 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 has not yet been ratified by the New Zealand government.

iii GNS Science research programme for petroleum exploration
MBIE has awarded NZ$9.6 million over four years to GNS Science to fund a research programme focusing on improving the chances of finding oil and gas accumulations in New Zealand’s sedimentary basins.

The research will focus on petroleum movement underground, and how petroleum is affected by the particular rock formations that generate, or are likely to generate, petroleum (‘source rocks’). The research has also attracted co-funding from international oil exploration companies and has a broad scope. It is hoped that this programme will help encourage and assist new exploration investment in New Zealand.

iv 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 (PCBU). 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.

v 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:

- introducing a financial assurance requirement sufficient to cover the costs of well control;
- 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
- 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.

Changes proposed to the Crown Minerals Act 1991

The Crown Minerals Amendment Bill passed its first reading on 3 May 2018 and is currently before the Select Committee. The Bill proposes to make a number of changes to the Crown Minerals Act 1991, including:

- 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;
- 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; and
- clarifying the access provisions for land set out in Schedule 4. Under the Bill, 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.

A report on the Bill from a Parliamentary Select Committee (which is a required step before the Bill returns to Parliament as a whole to be voted on) is expected in November 2018.
Chapter 20

NIGERIA

Israel Aye, Laura Alakija and Ogbongbemi Aminu

I  INTRODUCTION

The Nigerian oil and gas industry is over 60 years old and has grown steadily since the first significant oil find in 1956 into becoming the mainstay of the Nigerian economy. With 28.2 billion barrels of proven crude oil reserves and total proven gas reserves of 165 trillion standard cubic feet (scf), including 75.4 trillion scf of non-associated gas, Nigeria is often referred to as a gas province with pockets of oil. Nigeria has a maximum production capacity of 2.5 million bpd. Government participation in the industry is through the national oil company, the Nigerian National Petroleum Corporation (NNPC).2

Nigeria has 34 pieces of legislation, excluding regulations and directives, regulating various aspects of the industry. The Petroleum Industry Bill (PIB)3 pending before the National Assembly aims to harmonise all the legislation and significantly restructure the industry, particularly the functions of the various regulatory agencies, with a view to eliminating overlaps. All information available to us indicates that the government intends to break the PIB into at least four separate bills to deal with the industry reform, fiscal framework and revenue management of the oil and gas industry. The Nigerian Senate recently approved the Petroleum Industry Governance Bill (SB.237) (Governance Bill), which deals mainly with the governance and institutional framework for the petroleum industry. The Petroleum Industry Fiscal Bill (PIF), the Petroleum Industry Administration (PIA) Bill and the Petroleum Host Community (PHC) Bill are currently before the Senate for consideration. For the avoidance of doubt, as at the date of this article, none of the bills have crystallised into law.

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 regime4 and its content development drive5 has led to increased participation of indigenous oil companies in the petroleum industry.

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2 The NNPC has 13 subsidiaries, among other ventures, through which it fulfils all of its commercial and statutory functions.

3 First proposed in 2007 and has undergone several iterations. The current iterations resulted in the development of four bills, which are at different stages in the legislative process.

4 Introduced through Paragraph 16A of the First Schedule to the Petroleum Amendment Act – giving the president (and the licensee) the right to farm out any marginal field that has not been in production for at least 10 years.

5 Through the Nigerian Oil and Gas Industry Content Development (NOGICD) Act 2010.
The midstream and downstream sectors are dominated by indigenous players. Both sectors, with the exception of liquefied natural gas (LNG), are significantly underdeveloped as Nigeria’s refineries are currently producing approximately 10 million litres of petroleum products per day in comparison with Nigeria’s daily consumption of about 35 million litres per day. As a result, there is heavy reliance on imports 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. We hasten to add that these ‘executive actions’ are not underpinned by any piece of legislation as yet.

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.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

The Constitution 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;

e the Nigerian National Petroleum Corporation Act – establishing the NNPC and empowering it to participate directly in petroleum operations on behalf of the federal government;

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8 Petroleum Act Sections 2, 4 and 9.
10 Ibid., Sections 9, 20, 21–23, 56.
12 Ibid., Sections 3, 4 and 5.
14 Cap N123, LFN 2004. See particularly, Section 5, 6 and 10.
the Environmental Impact Assessment (EIA) Act\textsuperscript{15} – providing the framework for assessing the impact of oil and gas projects on the environment;\textsuperscript{16}
g 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.;\textsuperscript{17}
h the Education Tax Act\textsuperscript{18} – 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;
i the Niger Delta Development Commission (Establishment) Act\textsuperscript{19} – 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;\textsuperscript{20}
j 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;\textsuperscript{21}
k 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;\textsuperscript{22}
l the Oil Pipelines Act;\textsuperscript{23} and
m the Oil in Navigable Waters Act.\textsuperscript{24}

\textbf{ii Regulations}

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.\textsuperscript{25} 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 Nigerian Content Development and Monitoring Board (NCDMB) and the National Oil Spill Detection and Response Agency (NOSDRA).

\textsuperscript{15} Cap E12, LFN 2004.
\textsuperscript{16} Ibid., Section 2 and Paragraph 12 of its Schedule.
\textsuperscript{17} 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 same to the Federal Inland Revenue Service.
\textsuperscript{18} Cap E4, LFN 2004.
\textsuperscript{19} Cap N86, LFN 2004.
\textsuperscript{20} Ibid, Section 14(b).
\textsuperscript{21} See particularly NOGICD Act Sections 11 and 106.
\textsuperscript{22} See particularly, NEITI Act Section 3.
\textsuperscript{23} Cap O7, LFN 2004.
\textsuperscript{24} Cap O6, LFN 2004.
\textsuperscript{25} See Petroleum Act, Sections 8 and 9.
iii Treaties
Nigeria is a signatory to the International Center 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. 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.

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26 See NIPC Act, Section 26(3).
29 Ibid.
30 Paragraph 3, First Schedule to the Petroleum Act.
31 Paragraph 7, ibid.
33 Paragraph 6, First Schedule to the Petroleum Act.
34 Section 2, Deep Offshore and Inland Basins Production Sharing Contracts Act.
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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**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\(^{35}\) and 2.5 million bpd\(^{36}\) 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:  
\[
a \quad \text{have a minimum annual turnover of US$100 million and a net worth of at least US$40 million;}
\]
\[
b \quad \text{own a refinery or sales outlet;}
\]
\[
c \quad \text{be an established and globally recognised oil and gas marketer with evidence of operations and of volumes of crude handled in the last three years; and}
\]
\[
d \quad \text{provide a US$1 million performance bond, among other contractual arrangements.}
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\(^{35}\) OPEC, Annual Statistical Bulletin 2013, p. 10.  
\(^{36}\) Member Countries’ Crude Oil Production Allocations, Available from www.opec.org/opec_web/static_files_project/media/downloads/data_graphs/ProductionLevels.pdf.
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.

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 such transfers require the Minister’s consent. The decision has been appealed and this position is not settled under current legislation. However, the PIB attempts 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.

37  First Schedule, Paragraph 14, Petroleum Act and Regulation 4 of the Petroleum (Drilling and Production) Regulations (the Regulations).
38  Regulation 4(b) of the Regulations.
40  See PIB, Section 194(1) and (2).
42  Section 16, Petroleum Act.
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.

45 Section 21(2) PPTA.
46 Section 22(1) PPTA.
47 Section 22(2) PPTA.
48 Paragraph 4 and Table II of 2nd Schedule of PPTA.
iii Other applicable taxes
The NDDC\textsuperscript{49} 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{50} 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{51} 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{52}

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{53} projects. The incentives\textsuperscript{54} 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 useable 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 specialised 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{55} from petroleum operations. Key laws and regulations are:

\begin{itemize}
  \item[a] the Mineral Oils (Safety) Regulations;
\end{itemize}

\textsuperscript{49} The Niger Delta Development Commission.
\textsuperscript{50} See Section 14(b) NDDC Act.
\textsuperscript{51} Established and constituted in accordance with Section 1 of the Corporate Income Tax; See Section 2 PPTA.
\textsuperscript{52} The jurisdiction covers Nigerian territorial waters, continental shelf and Exclusive Economic Zone (EEZ).
\textsuperscript{53} Section 12 of the PPTA.
\textsuperscript{54} Subsection 2 further provides for conditions for the incentives.
\textsuperscript{55} Section 9(1)(b)(iii) of the Petroleum Act.
the Oil in Navigable Waters 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; and
the Harmful Waste (Special Criminal Provisions, etc.) Act.  

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. 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 flaring (where the Minister is satisfied that utilisation or reinjection is not appropriate or feasible in a particular field or fields).

### 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. 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:

- the Geneva Convention on the Continental Shelf 1958 (the Geneva Convention)\(^{61}\)
- the United Nations Convention on the Law of the Sea 1982 (UNCLOS); and

EGASPIN (2002)\(^ {62}\) also introduces new offshore decommissioning provisions that mirror the International Maritime Organisation (IMO) 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, 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 Act\(^ {63}\) (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.\(^ {64}\) 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 Nigerian-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:

- incorporation of the entity with the Corporate Affairs Commission;
- registration of the company’s tax obligations with the FIRS;
- registration with the Nigerian Investment Promotion Commission (NIPC)\(^ {65}\) (for companies with foreign participation); and
- 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.


\(^{62}\) EGASPIN, 327.

\(^{63}\) Cap C20, LFN 2004.

\(^{64}\) Section 54(1), CAMA.

\(^{65}\) Section 20 NIPC Act, Cap N117, LFN 2004.
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.

ii Capital importation

A company investing or doing business in Nigeria may import capital for such purposes. The Nigerian Investment Promotion Commission (NIPC) Act\(^{66}\) and the Foreign Exchange (Monitoring and Miscellaneous Provisions) (FOREX) Act\(^{67}\) 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;\(^{68}\)
- \( b \) 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;\(^{69}\)
- \( c \) 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;\(^{70}\)
- \( d \) operators are required to submit a Nigerian content plan demonstrating compliance with the requirements of the Act;\(^{71}\) 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.\(^{72}\)

\(^{66}\) Sections 20, 21, and 24, NIPC Act.
\(^{67}\) Sections 12, 13 and 15, FOREX Act. Cap F34, LFN 2004.
\(^{68}\) Section 3(1), Local Content Act.
\(^{69}\) Section 3(3) ibid.
\(^{70}\) Section 10(1), ibid.
\(^{71}\) Section 7, ibid.
\(^{72}\) Section 51(1), ibid.
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, 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 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.

CURRENT DEVELOPMENTS

The Nigerian government is intent on restructuring the petroleum industry and as such proposed a comprehensive set of bills and policies to underpin the legal framework of the petroleum industry in Nigeria. The oil and gas policies have been approved by the Government, while the fiscal policy is still being circulated among stakeholders and the public for consultation. The Federal Executive Council approved the 2017 National Gas Policy (NGP) on 28 June 2017. The NGP sets the goals, strategies and an implementation plan for establishing a framework that will drive the institutional, legal, regulatory and commercial reforms necessary for attracting investment into the gas sector. The Policy aims to set out in clear terms the framework necessary to move Nigeria from a crude oil export-based economy to an oil and gas based industrial economy.

The government has also introduced an initiative; the National Gas Flare Commercialisation Programme (NGFCP), which seeks to eliminate routine gas flares by 2020, reduce the government’s financial exposure, and drive positive social, environmental and economic impacts in the Niger Delta by mobilising private sector capital towards gas flare capture projects.

As indicated in the introductory section of this chapter, it appears the present administration intends to split the PIB into at least four separate bills to address the industry reform, fiscal framework and revenue management of the oil and gas industry. The Nigerian Senate passed the Petroleum Industry Governance Bill (the Governance Bill), which deals mainly with the governance and institutional framework for the petroleum industry. The Governance Bill seeks to establish a clear dichotomy between policymaking, regulation and commercial activities, and the authorities or bodies that are charged with those respective functions. It also seeks to engender value addition, transparency, accountability and a re-orientation towards optimal profit creation for national petroleum assets. If the Governance Bill is assented by the president, it will fundamentally restructure some organisations, like the Nigerian National Petroleum Corporation and the Department of Petroleum Resources, while setting up new ones like the National Petroleum Assets Management Commission.

73 The NEITI Act 2007.
The following Bills are also under consideration by the Senate:

a the Petroleum Industry Fiscal (PIF) Bill: This seeks to establish a robust fiscal framework that ensures the development and exploitation of petroleum resources in a rational and sustainable manner;

b the Petroleum Industry Administration Bill (PIA): This seeks to create a legal framework for the administration of upstream licenses and leases; provide regulations for the organisation of the midstream operations and gas market and set out the procedures for administration of licencing and operations of the downstream; and

c the Petroleum Host Community (PHC) Bill – seeks to provide a legal framework for cost and benefit share among the government, oil and gas companies and host communities.

Our sense is that the legal and regulatory framework of the petroleum industry in Nigeria is yet to fully crystallise.
Chapter 21

NORWAY

Yngve Bustnesli

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 15–20 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 2017, 36 exploration wells were spudded on the NCS and 11 discoveries were made. Most of the new discoveries are small and near existing or planned infrastructure. At total of 85 fields were in production while nine fields were under development by the end of 2017. In addition, 10 plans for new developments (PDOs) were submitted to the authorities during 2017.

In 2017, these fields produced almost 234 million Sm³ of marketable petroleum. Oil production rose in 2017 for the fourth year running. Important reasons for this are higher production regularity of Norway’s oil fields and new fields coming on stream. Norway supplies about 2 per cent of the global oil consumption. Gas production remained high in 2017, at about the same level as in 2016. Gas sales totalled 117 billion Sm³ in 2017. The growing demand for natural gas in other parts of Europe is an important explanation for this rise. In 2017, natural gas accounted for almost 50 per cent of total production by oil equivalents. The Norwegian Petroleum Directorate (NPD) estimates that the overall production from the NCS will remain relatively stable in 2018–2019. 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, 7.1 billion Sm³ oil equivalents or 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 will reach 165 billion kroner in 2019, while the export value of crude oil and natural gas was about 414 billion kroner in 2017.

The oil and gas sector is Norway’s largest measured in terms of value added, government revenues, investment and export value. In 2017, 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 is estimated to approximately 224 billion kroner in 2018. This represents an increase in revenues of more than 45 per cent since 2017, 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 18 August 2018, the fund was valued at approximately 8,700 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:

- the Petroleum Regulations No. 653 of 27 June 1997 (the Petroleum Regulations);
- the Resource Management Regulations No. 749 of 18 June 2001;
- the Regulations Relating to the Use of Facilities by Others No. 1625 of 20 December 2005; and
- 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:

- the Regulations on Petroleum Taxation No. 316 of 30 April 1993;
- 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;
- the Regulations Relating to Taxation on Rental of Moveable Production Facilities No. 819 of 18 August 1998; and
- the Regulations for Determining the Norm Price No. 5 of 25 June 1976 (the Norm Price Regulations).

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).

Source: Norges Bank – Investment Management, see www.nbim.no.

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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 main 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 Governmental bodies

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 Communications, 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 and Communications.

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. See more information about the recent licensing rounds in Section IX.

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 case 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 over the past 45 years.

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 is reflecting 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.

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. It is stated in Petoro’s annual report of 2014 that the pre-emption right has never been exercised, and we have not obtained information indicating a shift in this practice. The pre-emption right does not apply to transactions involving transfer of shares.

VI TAX

Petroleum activities on the NCS are governed by the Petroleum Taxation Act. The Act levies a special tax of 55 per cent in addition to the ordinary corporate tax rate of 23 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 5.3 per cent per year over a four-year period on capital investments, in total 21.2 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 2018 is 1.06 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 such 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 sub-sea and onshore activities forming an integrated part of the offshore petroleum production are set out in the following regulations:

1. the Framework Regulations of 12 February 2010 No. 158;
2. the Management Regulations of 29 April 2010 No. 611;
3. the Facilities Regulations of 29 April 2010 No. 634;
4. the Activities Regulations of 29 April 2010 No. 613; and
5. the Technical and Operational Regulations of 29 April 2010 No. 612.

As a general rule, all mobile offshore facilities are required to obtain an acknowledgment of compliance before starting activities. 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.

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 alternatively 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 alternative 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 an alternative financial liability for decommissioning costs related to installations existing at the time of the transfer. To ensure fulfilment of this potential alternative 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 at the time of decommissioning 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 such 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 promoting revenue transparency and accountability in the extractive sector, including the oil and gas sector.
IX CURRENT DEVELOPMENTS

Following the delimitation agreement entered into between Norway and Russia effective 7 July 2011, the Barents Sea south-east area has subsequently been opened for production of oil and gas and the very first licences in this area were awarded in the 23rd licensing round. The awards were announced by the MPE on the 18 May 2016. Thirteen companies were awarded participating interests in 10 different production licences consisting of 40 prospective blocks. On 21 June 2017, the MPE announced the 24th licensing round. The licensing round includes a total of 102 blocks. Nine blocks are located in the Norwegian Sea and 93 in the Barents Sea. The award took place 18 June 2018, and the MPE offered 11 companies 12 new licences in 47 blocks. Nine of the licences are located in the Barents Sea, while three are located in the Norwegian Sea.

At the application deadline on 1 September 2017, a total of 39 companies had submitted applications for new acreage in the yearly licencing round, which includes the most mature areas on the NCS (APA 2017). On 16 January 2018, a record number of 75 new production licences were awarded to 34 different oil companies. The 75 licences were located in the North Sea (45), the Norwegian Sea (22) and the Barents Sea (8) respectively. All the new licences were awarded with work-programme obligations, which help to ensure continued activity on the NCS.

Thirty six exploration wells were spudded on the NCS and 11 discoveries made during 2017. Five new fields started to produce in 2017, while a further nine fields were under development. A record number of 10 new field development plans were delivered to the authorities in 2017.4

Several major oil discoveries are planned for development, and overall there has been an increase in recent development projects. A total of 20 development projects are currently ongoing on the NCS. The development of the Equinor-operated Johan Sverdrup field stands out as the project people in the industry are most enthusiastic about. The 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 550,000–650,000 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 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 PDO was approved by the authorities in June 2018, and the field is expected to be producing for 30 years.

It is expected that major field developments 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 is continuing to be one of the most prosperous petroleum provinces in the years to come.

4 Sources: The Norwegian Petroleum Directorate (www.npd.no) and Norwegian Petroleum (www. norskpetreleum.no)
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 are among 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 until 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 doubts. Since the claimants argued that the tariff reduction was also in breach of the European Convention on Human Rights, Protocol 1, Article 1, about the protection of proprietary rights, the case may in theory also be brought before the European Court of Human Rights. It remains to see whether this option is utilised or if the final chapter has already been written by the Norwegian Supreme Court.

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.
I  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 – is still 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:

\[ a \] 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;
\[ b \] it extends the exploration period to 10 years;
\[ c \] 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
\[ d \] 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

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1 André Duarte Figueira is senior associate, Diogo Ortigão Ramos and Lourenço Vilhena de Freitas are partners and João Sequeira Sena is an associate at Cuatrecasas.
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, the current operator 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, the government revoked certain concessions covering onshore areas in the southern coast on procedural grounds and partly motivated by environmental pressures.

Overall, the authorities’ attitude has been passive, responding to the initiative of interested companies rather than embarking on promotion, and reluctant to raise local unrest due to the population’s environmental concerns on exploration projects. This, coupled with the perception that the country presents a high exploration risk, has resulted in a 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 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 may affect exploration operations: in at least one case, the formal signature of the concession agreement was delayed when activities scheduled to be started in the areas off the southern coast raised concerns in the press that tourism could be negatively affected by these oil exploration operations. This situation is now resolved and operations are expected to begin shortly.

However, the combination of technological advances that enable exploration and production operations at ever greater depths, with the development of geological knowledge (and further discoveries made in the Grand Banks area), and a flexible and overall favourable legal and tax regime could justify a fresh look at the country’s petroleum potential.

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), 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 Energy Sector National Entity (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 the ENMC’s powers to the DGEG, 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

Oil and gas system is ruled out by Decree-Law 31/2006, of 15 February, that settles the General Framework for the Organization and Functioning of the National Oil System, as amended by Decree-Law 244/2015, of 19 October and that specifically governs refining, storage, transport and distribution. These activities are not subject to prior licensing, save regarding environmental licensing when applicable, industrial facilities licensing 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

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4 For the English version of the texts of the legal documents mentioned in this section, visit www.enmc.pt/en-GB/activities/exploration-and-production-of-petroleum-resources/legislation/.
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:

- 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.
- 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.
- Joint Dispatch No. A-87/94-XII, establishing surface rental charges.

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.  

**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 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, 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.

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5 For further details, see Section III.
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 ENMC 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 ENMC 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 ENMC. If no public bidding is announced, the ENMC 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.

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:

a at the end of the initial period if the concessionaire has not demarcated an oilfield, or at the end of the production period;

b at 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 at any time, by mutual agreement of the state and the concessionaire;

d at 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 at 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 ENMC’s prior authorisation.


ii Regulation

The ENMC 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 ENMC to resolve any issues concerning a concession agreement or a preliminary evaluation licence.

The ENMC 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.

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.

iii 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. According to the Decree-Law, concession agreements must contain an arbitral clause.

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6 In this case, the arbitral procedure would likely be ruled by the arbitral procedure regulation in Act 63/2011, published on 14 December.
Portugal has concluded bilateral investment protection treaties with 53 countries,\(^7\) and has signed treaties to avoid double taxation with 79 countries based on the OECD model.\(^8\)

### III LICENSING

Concession agreements that comply with the Decree-Law are the means of granting oil and gas exploration and production rights.\(^9\) 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.\(^{10}\)

\(b\) 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 included in a general development and production plan (see below). This phase lasts eight years\(^{11}\) 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 ENMC before the end of October. This work programme must include a budget for activities to be carried out in the following year. The ENMC 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 ENMC.

\(e\) 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 ENMC's approval. The concessionaire must request this approval with 30 days' advance notice. The ENMC 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 ENMC of any contracts

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\(^7\) 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.

\(^8\) 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.


\(^10\) For deep offshore areas, these limits may be exceeded.

\(^11\) For deep offshore areas, the duration limit may be exceeded.
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 ENMC 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.

b 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). 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 ENMC 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 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 ENMC 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.

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 ENMC the plans and measures necessary to ensure fulfilment, keeping them permanently updated.

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12 For deep offshore areas, the area to be relinquished may be smaller.
13 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.
Environmental protection: The concessionaire must adopt all necessary measures and precautions to minimise the environmental impact of its activities, and must submit to ENMC its environmental protection plans in a timely manner as per applicable legal provisions.

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.

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 ENMC'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.

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 ENMC, 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 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 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>

The concessionaire is subject to corporate income tax at the applicable rates, which is levied on its profits. The following tax rules shall also be considered:

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);

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;

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:

• 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

• 45 per cent of the amount of the taxable income that would be calculated before determining the amount to be allocated to the provision.

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14 These amounts were set in 1995 in the Joint Dispatch mentioned above.
15 See Article 51 of Decree-Law No. 109/94, dated 26 April.
16 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 1.5 per cent municipal surcharge applies, being a state surcharge applicable as follows:

- taxable profits in excess of €1.5 million = 3 per cent;
- taxable profits in excess of €7.5 million = 5 per cent; and
- taxable profits in excess of €35 million = 9 per cent.
17 See Article 42 of the Portuguese Corporate Income Tax Code and Article 50 of Decree-Law No. 109/94, dated 26 April.
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.

VII 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 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 licenses 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 ENMC, 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 ENMC'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 ENMC 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:

a. 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;

b. 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);18

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18 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.
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;

the company is registered with the commercial registry office;

the incorporating documents are published online;

the start-up is notified to the tax authorities;

the company and its corporate body members are registered with social security; and

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.

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.
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.

Ten of the 15 concession contracts for prospection, research and exploration of hydrocarbons in Portugal have been cancelled or revoked in 2017, particularly motivated by environmental and political pressures. Some terminations have been challenged and are subject to arbitration procedures. Currently five concession contracts remain in force, two (named ‘Batalha’ and ‘Pombal’) operated by Australis Oil & Gas Portugal, Lda since 30 September 2015, on the Onshore Lusitanian Basin, and the remaining are in the Deep Offshore of the Alentejo Basin, currently operated by a consortium between Eni and Galp.

An exploration well that was planned for the Offshore Alentejo Basin in the summer of 2016 has been approved but postponed to September/October 2018. In 2017, authorities requested additional environmental impact reports, which have taken longer than anticipated. This, in turn, has meant that the meteorological window for exploration in Offshore Alentejo Basin was lost in 2017.

The Eni/Galp consortium wants to initiate an oil drilling survey in the deep offshore of the Alentejo Basin, 46.5 kilometres off the coast of Aljezur, and has required and been granted a title of exclusive use of the national maritime space by the General Directorate of Natural Resources, Safety and Maritime Services.

According to the request ‘[t]he survey will be carried out using the Saipem 12000 (Ultra Deep Water Dynamic Positioning Drilling Ship), 46.5 kilometres off the coast of Aljezur, and ’at a maximum depth of 1,070 meters in the Exclusive Economic Zone’.

However, although the drilling survey was approved, an interlocutory order issued by the Loulé Administrative Court suspended once again the approved drilling survey claiming that there was ‘a serious risk for the environment, even in the preliminary stage of the drilling operations’.
I INTRODUCTION

Russia is a major global producer, supplier and consumer of oil and gas. In 2017, Russia was once again the world’s largest exporter of natural gas by pipeline and its production and export of oil have again increased. Its share of total global exports of LNG remained modest, but comparable with historical exporters of LNG, such as Algeria. 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. In the medium term, Russia 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. The worsening geopolitical situation since 2014, and the sanctions 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 a material impact on Russia’s ability to maintain growth in the resources basis and production levels. About one-third of the global natural gas production increase in 2017 is attributed to Russia.

Europe is the main market for Russian hydrocarbons. Given the present geopolitical environment, 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 July 2018, it began shipments of LNG to China via the Northern Sea Route. This is likely to affect the legal environment for the industry. In the meantime, Russia’s pipeline gas exports to Europe have set new records both in 2017 and 2018, and its pipeline exports have increased by 15 bcm. This is set to increase further as a result of the proposed Nord Stream 2 gas pipeline to Germany.

The oil and gas industry in Russia remains robust. Russia has been active in the Vienna group’s efforts to bring oil production and consumption into balance via modest cuts in oil production.

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1 Natalya Morozova and Rob Patterson are partners at Vinson & Elkins.
2 According to BP’s Statistical Review of World Energy 2018.
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:

a. the purpose of the subsoil use;
b. the borders of the land plot granted for subsoil use;
c. the deadlines (such as the start and end of the production);
d. the production volume; and
e. 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. a licence for the geological exploration and assessment of a subsoil plot;
b. a licence for the production of natural resources; and
c. 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

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. In addition, 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. Such 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. Such prohibition specifically affects Russian Arctic oil and gas programmes. Non-Russian companies participating in such 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 such transferee is not prohibited under the Subsoil Law or, alternatively, the resolution of the government granting consent to such transfer. If such 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 such 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
The state of corruption in Russia is often characterised as endemic. 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 main problems that Russia faces in attempting to secure increased levels of foreign direct 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.

IX CURRENT DEVELOPMENTS
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 to export LNG, in addition to Gazprom and its subsidiaries, those subsoil users whose subsoil licence provides for the construction of an LNG plant as of 1 January 2013, as well as those state-controlled companies whose deposits are located within territorial waters, internal seas, on the continental shelf, or the Black and Azov Seas. The effect of this ‘liberalisation’ (and
its obvious purpose) was to benefit Yamal LNG (in which stakes are owned by NOVATEK, Total, CNPC and the Silk Road Fund) and Rosneft, without restricting Gazprom's monopoly to supply natural gas through pipelines to external markets.

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 24

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 sub-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 the world’s largest exporter 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. T&T has one oil refinery located at Pointe-a-Pierre, which is operated by a state-owned company, Petroleum Company of Trinidad and Tobago Limited (Petrotrin). Over the years, considerable sums have been spent upgrading this facility; however, the government has very recently announced a decision to shut down the refinery operations.

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

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3 History of Petroleum Exploration in Trinidad and Tobago, Search and Discovery Article #70231 (2016), K M Persad and C Archie.
affected the petrochemical sector. Reports for 2018 are promising, with increasing global oil prices, the announcement of new gas discoveries and the upstream operators reconfirming their commitment to invest in T&T.

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 objectives are to promote economic integration, foreign policy coordination, human and social development and security within the Caribbean.4 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 including Canada, China, Cuba, the UK and the US, designed to encourage favourable

4 https://caricom.org/about-caricom/who-we-are.
conditions for investors of those countries to make investments in T&T. 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 such 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 arbitration procedure.

The Convention on the Recognition and Enforcement of Foreign Arbitral Awards, 1958 (the New York Convention) 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 (the ICSID Convention) 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 17 double taxation treaties including treaties with Canada, CARICOM, China, the UK, the US, Venezuela and several European countries. These treaties either reduce or completely mitigate the taxes imposed by the home treaty country on residents of the other treaty country.

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 the extent of each MEWP 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. Exploration licences 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 are to be made in writing to the Minister who must then publish them in the Gazette and at least one local daily newspaper to allow opportunity for public objection. An application fee of TT$500.00 is payable. If the application is in order, the Minister will decide the application after considering any objections.

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. Although not usual, 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 can be renewed for a maximum term of 25 years, with further successive five-year extensions. Extensions of the initial term are possible even 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.

Apart from the payment of production royalties, Licences tend to incorporate a combination of the following fiscal obligations including performance guarantees for the agreed MEWP (which will vary between licences), 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 remediation of pollution 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 Licenses, 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 remediation of pollution 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, however, 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 are typically expressed in E&P Licences and PSCs. Termination can be triggered as a result of breach or pursuant to the normal expiry of the term or via voluntary relinquishment prior to the term’s 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. PSCs tend to address the issue of exportation in more detail and the ability to export natural gas is more restricted. Marketing arrangements for any natural gas are subject to the Minister’s approval. In applying for approval, 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.

V 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. The Minister’s prior written approval is also needed for the
issue of a sub-licence 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.

VI 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 2016) was 48.6791608 cents per barrel of crude and 8.3929588 cents per mscf of natural gas. The 2017 rates will be published in late 2018.

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.

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.

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:

a. GFL (0.3 per cent of gross income);

b. VAT (at 12.5 per cent on imports and T&T based commercial supplies save where zero-rated or exempt);

c. Customs duties (at varying rates on imports according to the common external tariff);

d. Withholding tax on distributions and named species of payment to non-residents (at 5 per cent, 10 per cent and 15 per cent);

e. PAYE, national insurance and health surcharge on emolument income paid to employees (the employer is responsible for deducting and remitting same to the Revenue);

f. Stamp duty (levied at varying specified statutory rates on various instruments); and

g. 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 incorporated into concessions. These usually involve the Contractor/Licensee making an environmental plan and setting up escrow accounts for the remediation of pollution 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

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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 waters. These statutes are, however, quite old with very small penalties and do not adequately address liability for marine related petroleum pollution. T&T is also a party to several international conventions that are specific to oil spills, but several of these have not been incorporated into domestic law.
Compensation) Regulations (made law pursuant to the Act) 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),\(^8\) 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 moveable structure. The OSH Act is designed to revise and extend the law regarding the safety, health and welfare of persons at work and in so doing 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.

\(^8\) \url{www.ema.co.tt/new/}.  

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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 incorporation9 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 buying and selling of foreign currency in T&T, and persons may freely buy, sell or borrow foreign currency from 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 period exceeding 30 days if a work permit is obtained from the Ministry 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).

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9 This notice must also be filed prior to any share issuance by the company to a foreign investor. Consideration for such shares must also be paid for in an internationally traded currency through a licensed dealer of foreign exchange.
iii Anti-corruption

Transparency International’s 2017 Corruption Perceptions Index show an improvement in T&T’s ranking from its all-time high of 101 in 2016 to 77 in 2017. 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 public 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 downstream petrochemical industry has thrived over the years because of a consistent and inexpensive supply of natural gas. However, the industry is facing challenges owing to gas supply shortages. While concerted efforts are being made by the MEEI and upstream operators, it is likely that these difficulties will continue for the near to medium term.

As a result of low energy prices, effective 1 January 2018 the government amended the Regulations in an effort to expand and standardise the royalty rate applicable to public E&P Licences and PSCs by fixing this at 12.5 per cent calculated on the net volume of crude oil and natural gas won and saved from the licensed or contract area at fair market value. This has caused concern among PSC contractors that were not previously liable to pay royalties. 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.

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The MEEI has given notice that a 2018 competitive bid round will be launched, involving six shallow water blocks and one onshore block consisting of two non-contiguous acreages. The Shallow Water Blocks are located off the north, west and east coasts of Trinidad, while the Onshore Block, a subset of the historical Central Range Block, is located in central Trinidad. We are not yet aware when these bid rounds will be officially launched.

Chapter 25

UNITED KINGDOM

Jason Lovell, Jubilee Easo and Chris Pass

I INTRODUCTION

The UK oil and gas industry continues to experience an overall upturn in the first half of 2018, relative to recent years. Capital expenditure in the industry was relatively low in 2017, and it had been forecast that fresh investment in 2018 could see capital expenditure increase for the first time in four years. Although the low level of new project and drilling activity continued into the first six months of 2018 there is some cause for optimism with six major new project final investment decisions being made in the first eight months of 2018. The turbulent times of the past few years have prompted some positive trends in market performance. Development efficiency has improved, with projects routinely completing on time and under budget, and production efficiency has risen for a fifth consecutive year. The rising oil price, which hit US$70/bbl in early 2018 for the first time in three years, has provided a welcome boost to margins for exploration and production companies.

The past two years have also seen renewed optimism and a significant upturn in M&A activity with the re-emergence of private equity investment. There has been a general trend towards divestment from the major players, and investment from smaller independent companies through private equity finance, with a healthy variety of deal types and sizes last year and investment in the UK continental shelf (UKCS) continuing to rise. Looking back on 2017, the value of UK upstream mergers and acquisitions surpassed US$8 billion, which represents continuing confidence in the UKCS.

The UKCS is still a significant basin in terms of production, which the Oil and Gas Authority estimates will total 11.7 billion barrels of oil equivalent (boe) over the period from 2016 to 2050, 2.8 billion boe higher than prior estimates. There are a number of undeveloped fields in the UKCS, with geological surveys showing 20 billion boe yet to be recovered, and significant exploration upside in harsher operating areas like West of Shetland. The government is encouraging investment in these exciting prospects through policy decisions, including relaxed licence conditions, and financial incentives, like the current proposal to allow the assignment of tax history between incoming and outgoing licence holders (see detailed explanation in Section VIII).

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1 Jason Lovell is a partner, Jubilee Easo is a legal director, and Chris Pass is an associate in the oil and gas team of Eversheds Sutherland (International) LLP, based in London.
3 Oil and Gas UK Business Outlook 2018.
4 Oil and Gas UK Business Outlook 2018.
II LEGAL AND REGULATORY FRAMEWORK

The primary legislation that sets out the regime under which petroleum is explored for, developed and produced in the UK is the Petroleum Act 1998 (as amended) (the Petroleum Act). Since 1934, there have been various pieces of legislation governing the rights to exploit petroleum in the UK, all of which are currently consolidated in the Petroleum Act. Under the Petroleum Act, ownership of petroleum vests in the Crown with Her Majesty having the exclusive right to explore for and develop onshore and offshore petroleum resources. Crude oil, gas and shale gas all fall within the definition of petroleum in the Petroleum Act and are governed by the same regime.

The Petroleum Act operates a licence regime under which licences are granted to persons to ‘search and bore for and get’ petroleum. The holder of a licence is granted the right to explore and develop a geographical licence area in return for a fee. If the licence holder successfully develops an oil or gas field, ownership of the petroleum within the licence area transfers from the Crown to the licence holder at the well head. The rights and obligations of the licence holder are contained both within the conditions of the licence and applicable laws (see detailed explanation below).

Historically, the Department of Energy and Climate Change (DECC) and the Secretary of State were together responsible for energy policy, regulation of the UK’s petroleum resources and oversight and implementation of the licensing regime. This changed in 2014, when the Wood Review recommended fundamental changes to the management and oversight of the UK petroleum regime, aimed at incentivising investment and ensuring that the petroleum industry remained relevant. One of the consequences of the Wood Review was the creation of a new department to replace DECC – the Department of Business, Energy and Industrial Strategy (BEIS) – and the creation of a new regulator – the Oil & Gas Authority (the OGA) – responsible for licensing on behalf of the Secretary of State and BEIS.

The OGA was initially established as an executive agency of BEIS. However, the Energy Act 2016 established the OGA as a fully independent regulatory body for both onshore and offshore petroleum resources, in the form of a company in which the Secretary of State for BEIS is the sole shareholder. The Energy Act 2016 also amended the Petroleum Act to assign to the OGA certain functions and powers that were previously held by the Secretary of State, and to vest the OGA with new powers, including the ability to:

a. participate in non-binding dispute resolution procedures, including disputes in relation to third party access to upstream petroleum infrastructure;

b. request information and data from participants in the industry;5

c. attend the meetings of participants in the industry; and

5 The Oil and Gas Authority (Offshore Petroleum)(Retention of Information and Samples) Regulations 2018 came into force in May 2018, placing obligations on relevant persons (including licensees, owners of upstream infrastructure and owners of offshore installations) to retain petroleum related information and samples, in most cases until they are provided to the OGA under Section 34 of the Energy Act 2016. The Oil and Gas Authority (Offshore Petroleum)(Disclosure of Protected Material After Specified Period) Regulations 2018 came into force in August 2018, and state when the OGA may publish information obtained under the Energy Act 2016. The time periods for disclosure have been linked to the nature of the relevant information or sample, taking account of the factors listed in Section 66 of the Energy Act 2016 (such as the risk of discouraging the acquisition of information or samples).
sanction industry participants for failure to comply with defined petroleum-related requirements (such as a failure to comply with the terms or conditions of an offshore licence). Sanctions include financial penalties up to £1 million, licence revocation and the removal of the petroleum field operator.

The relationship between BEIS and the OGA is governed by a framework agreement. While many powers have been transferred to the OGA, the Secretary of State still has overall responsibility for energy policy and is responsible to the parliament for the OGA. BEIS has retained responsibility for the regulation and enforcement of the environmental regime and decommissioning obligations. HM Treasury continues to be responsible for fiscal matters, and HM Revenue & Customs retains responsibility for tax retrieval. Other relevant bodies include the Health and Safety Executive (which is responsible for enforcing the health and safety regime), the Hazardous Installations Directorate (which regulates and promotes improvements in health and safety in offshore petroleum projects, regulates the natural gas supply industry, and regulates onshore and offshore pipelines) and the OSPAR Commission (which oversees the UK’s international obligations on the protection of the marine environment and decommissioning).

The Maximising Economic Recovery Strategy for the UK (MER UK Strategy), was produced by the Secretary of State in consultation with the industry and came into force in March 2016. The guiding principle of the MER UK Strategy is that:

relevant persons must, in the exercise of their relevant functions, take the steps necessary to secure that the maximum value of economically recoverable petroleum is recovered from the strata beneath relevant UK waters.

The Infrastructure Act 2015 is the legislative basis for implementing the MER UK Strategy. It amended the Petroleum Act by inserting a requirement to maximise the economic recovery of UK petroleum, through (among other things) collaboration between licence holders and the owners of upstream petroleum infrastructure.

The Petroleum Act is the principal legislation that applies to both the UK’s land (the landward or ‘onshore’ regime), and the UK’s territorial waters and continental shelf (the seaward or ‘offshore’ regime). UK territorial waters extend for 12 nautical miles from the low water mark as set out in the Territorial Sea (Baselines Order) 2014 (following the principles laid down in the Geneva Convention on the Territorial Sea 1958). In 1964, the UK ratified the Geneva Convention on the Continental Shelf 1958 and designated an area in the North Sea as the UKCS, which has, since then, been redefined a number of times further to boundary treaties with Belgium, Denmark, France, Germany, Ireland, the Netherlands and Norway. The Continental Shelf (Designation of Areas) Order 2013 replaces previous orders and designates what is now deemed to be the UKCS.

III LICENSING

The Petroleum (Transfer of Functions) Regulations 2016 vested in the OGA the exclusive right and responsibility to grant licences to explore for, develop and produce petroleum

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6 Onshore certain functions and powers of the OGA related to onshore petroleum licencing in Scotland and Wales have been devolved to Scottish Ministers and Welsh Ministers (see further below).
resources. Under the licence regime of the Petroleum Act, applications are made for licences to the OGA as part of an annual competitive licensing round. The licensing round is advertised on the OGA website and in the European Journal. The OGA also has an out-of-round application process typically initiated at a company’s request, through which the OGA grants licences over small areas, in exceptional circumstances.

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. A company can apply on behalf of itself or a joint venture. There are no express restrictions on foreign ownership, however, all applicants must be registered in the UK, either as a company or as a branch of a foreign company to ensure that they have a taxable UK presence. The UK does not have a national petroleum company and the government cannot directly make an application for a licence.

The OGA considers all applications on an individual basis and expects companies to meet certain financial and technical capability requirements. Licensees will need to have the financial ability to fulfil their obligations under the licence and complete the relevant work programme or proposed development. Each licence is required to have an operator to manage and supervise the exploration and development of the petroleum field. The operator requires the approval of the OGA as part of the licence application process. Where a company is taking on the responsibility of operatorship, it will need to have the technical capability to perform the role. Non-operators still require technical expertise sufficient to exercise responsible oversight of the project. There are also other requirements for licensees under the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015 (see Section VI).

In awarding licences, the OGA must comply with the Hydrocarbons Licensing Directive Regulations 1995, which implements certain EU directives in relation to petroleum licensing, including factors that may (or may not) be taken into account when deciding whether to issue a licence, and the minimum amount of public consultation required.

The OGA runs separate licensing rounds for onshore and offshore licences. On 10 July 2018, the OGA launched the 31st Offshore Licensing Round, offering a total of 1,766 blocks (370,000km²) of open acreage in frontier areas of the UKCS. Following the level of interest in the 30th Offshore Licensing Round, companies were also provided with the opportunity to nominate additional blocks in mature areas. The last onshore licensing round was held in 2014, with licences for 159 blocks being awarded as part of the 14th Landward Licensing Round. Except for the manner in which the licence areas are designated, the onshore and offshore regime are remarkably similar. The principal differences are the need for an onshore operator to comply with the environmental and planning laws that apply to England and Scotland and the recent devolution in Scotland and Wales of the OGA’s powers in respect of the licensing of onshore petroleum activities to the Scottish and Welsh Ministers respectively.

The UK licence takes the form of a deed, pursuant to which the licensee agrees to be bound by the terms of the licence and observe the general conditions of the licence. The conditions of the licence, also referred to as ‘model clauses’, are contained in secondary legislation, which are then incorporated into the licence. Up to the 19th licensing round,

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7 The Scotland Act 2016, the Wales Act 2017 and associated statutory instruments have seen responsibility for onshore petroleum licensing in Scotland and Wales transferred from the OGA to (respectively) Scottish Ministers and Welsh Ministers. The practical impact of this devolution of powers remains to be seen and will be an area of interest in the years ahead.
the model clauses were incorporated into licences by means of a single short paragraph. From the 20th round onwards the model clauses have been set out in full in the licence itself, for the sake of clarity. These model clauses include details such as the term, licence area relinquishment, minimum work obligations, appointment of the operator and record keeping. Existing licences are not affected by the issue of subsequent sets of model clauses (except through specifically retrospective measures).

The secondary legislation applying to current licences are:

a. the Petroleum Licensing (Exploration and Production) (Seaward and Landward Areas) Regulations 2004 for exploration licences, production licences and petroleum exploration and development licences for the 22nd and subsequent licensing rounds (offshore) and the 12th and subsequent licensing rounds (onshore);

b. the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008 for offshore production licences for the 25th and subsequent licensing rounds; and

c. the Petroleum Licensing (Exploration and Production) (Landward Areas) Regulations 2014 for onshore petroleum exploration and development licences issued in the 14th onshore licensing rounds, as well as new onshore exploration licences (see below).

Licences can be held by a single company or by several working together, but in legal terms there is only ever a single licensee despite the number of companies it may represent. All companies on a licence share joint and several liability for operations conducted under the licence. The Petroleum Act does not limit the liability of the licensee. Where more than one company forms the licensee, the companies will enter into a joint operating agreement and form an unincorporated joint venture to govern the relationship between them and apportion liability, costs and revenue. Such apportionment of the risk and reward under the licence requires the OGA’s approval.

The most common types of licences are as follows.

i. **Exploration licence**

This grants the licensee a non-exclusive right to carry out exploratory seismic or other surveys over relatively large geographical areas not already covered by a production licence. These are typically used by seismic contractors who wish to gather data to sell rather than to exploit the petroleum resources themselves. There are two types of exploration licence: one for offshore areas and one for onshore areas. As exploration licences are not exclusive, companies can apply at any time for a new exploration licence (or for an extension to an existing exploration licence). The licensee pays a flat rental charge for the exploration licence.

ii. **Petroleum exploration and development licence**

The onshore production licence is known formally as a petroleum exploration and development licence (PEDL). Licensees are granted the exclusive right to explore for and develop petroleum in a specified onshore area. Each licence carries an annual charge, called a rental. Rentals are due each year on the licence anniversary and are charged at an escalating rate on the area of the licence at that date. The PEDL runs for three successive terms or phases. The initial term is typically for five years and is the period during which the licensee performs the exploration work programme that it has agreed with the OGA during the licensing round. The licence will expire at the end of its initial term unless varied by agreement or the licensee has completed the work programme and relinquished 50 per cent of the initial licence area. The second term usually lasts for five years and is associated with
appraisal and development. The licence will expire at the end of its second term unless varied by agreement or the OGA has approved a field development plan. The third term is for 20 years and intended for construction of facilities and production. The OGA may extend the term if production is continuing.

iii  **Seaward production licence**

This is the umbrella name for three types of offshore licences under which licensees have been granted an exclusive right to explore for, develop and produce petroleum fields from the UKCS for future grants. These three types of offshore licences will be replaced by the ‘innovate licence’ for future grants (see below), but remain relevant for the majority of existing offshore production licences.

The ‘traditional licence’ is the most common offshore production licence. The initial exploration phase is typically for four years, during which the licensee must complete the minimum work programme. The licensee must relinquish 50 per cent of its acreage at the end of this phase, if it wishes to move onto the next phase. The second appraisal phase is also for four years, during which the licensee will need to submit its field development plan for approval by the OGA (the OGA published revised guidance on the requirements for UKCS field developments in May 2018). The final production phase typically has an 18-year term with the possibility to extend the term if production is continuing. An annual rental is payable, charged on the area of the licence. Like the PEDL, rental escalates each year after the initial exploration phase.

The ‘promote licence’ was introduced to allow smaller and start-up companies to obtain an offshore production licence first and gain the necessary operating and financial capacity later. The term of the various phases and the relinquishment obligations are the same as a traditional licence. However, during the first two years, the operatorship competence criteria (financial and technical capability requirements) for licensees are relaxed, and the annual rental rate is reduced by 90 per cent. The licence terminates if the licensee is not able to establish the requisite financial, technical and environmental capabilities, or the licensee has failed to make a firm drilling commitment (or agreed equivalent equally substantive activity) by the end of the initial two year period.

The ‘frontier licence’ was introduced to address the complexities in sourcing petroleum in remote areas of the UKCS and to allow for exploration over a larger area. The licensees benefit from an extended period to acquire seismic data in comparison to a traditional licence, during both the initial exploration phase (two more years for standard frontier licences and five more years for the harsher West of Shetland frontier licence) and the second appraisal phase (two more years for both types of frontier licence). The licensee has 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 of the remaining area at the end of the initial exploration phase. Like promote licences, the operatorship competence criteria will not be applied to frontier licence applications for the first two years and the annual rental rate is reduced by 90 per cent for the first two years.

iv  **Offshore innovate licence**

The 29th Licensing Round signalled the launch of a new type of offshore production licence called the ‘innovate licence’. The OGA announced that this licence would replace all other types of offshore production licences for all future licensing rounds including the 30th Licensing Round. These changes to the offshore model clauses were implemented through The
Petroleum and Offshore Gas Storage and Unloading Licensing (Amendment) Regulations 2017. The main difference between the innovate licence and older licences is the duration of the initial and second phase and the flexibility that licensees will have in determining the length of each phase. The initial term can be for up to nine years and the second term can have a duration of four years (the default position) but with a length of up to six years where technical challenges apply. The initial term will be divided into three phases: phase A – for studies and reprocessing; phase B – for acquiring new seismic data; and phase C – for drilling wells. The third term is usually 18 years, and may be extended for ongoing production.

IV ASSIGNMENTS OF INTERESTS

Any transaction that results in a company joining a licence or a company leaving or withdrawing from a licence is deemed to be a licence assignment. Any assignment of a licence, including affiliate assignments, requires prior consent from the OGA. Assignments made without prior consent are seen by the OGA as a very serious breach of the licence and as grounds for immediate revocation of the licence or an unwinding of the transaction.

The OGA will review and consider the form of the deed of assignment used by the parties. The OGA provides approved draft deeds of assignment on its website. There is some room for movement, but material changes will increase the time for obtaining the OGA’s consent.

Because an assignment requires prior consent, it is the existing licence holder who must apply to the OGA. Offshore licence assignments are processed through the Petroleum E-Business Assignments and Relinquishment system (PEARS), which forms part of the online UK energy portal. PEARS can be used by licensees to process several types of transactions: licence assignments, interest allocations, operator changes, licence administration changes, licence relinquishments and the surrender of acreage. Onshore licence assignments are still processed using an application form available on the OGA website, which also contains a guidance note on the information required in the application. Consent from the OGA lapses after three months, so completion of the relevant transaction must occur within that time, to avoid the need to request an extension.

When assessing an application, the OGA will consider matters including:

a. the technical capability of the transferee;
b. the financial resources available to the transferee (particularly if the licence has significant decommissioning obligations);
c. intragroup assignments (the OGA will want to be made aware of whether the transfer is the first stage of a corporate disposal);
d. change in operatorship; and

e. the ability of the transferee to comply with the Offshore Safety Directive.

A change of control does not strictly require the OGA’s consent, but will trigger powers of the OGA to require a further change of control or a revocation of the licence. As a result, ordinary practice is to apply to the OGA and seek comfort that the OGA will not exercise its powers. Any such application should demonstrate that the proposed transaction will not affect the ability of the licence holder to meet its obligations under the licence.

Creation of a charge over a licence requires the consent of the OGA. In 2012, the Secretary of State granted the Open Permissions (Creation of Security Rights Over Licences). Where the charge fits the description set out in the open permission, automatic consent is...
granted by the open permission and the licensee does not need to seek further individual approval from the OGA. However, in order to take advantage of the open permission, the licensee will need to notify the OGA of certain details of the charge within 10 days of its creation. Charges that are excluded from the open permission will need individual approval from the OGA. If the holder of a charge wishes to enforce the security interest it is a licence assignment and the normal licence assignment procedure will apply.

V TAX

There are two different means through which the UK gets a return from the production of petroleum (onshore and offshore):

a annual rentals payable under each licence (see Section III); and

b taxes on the profits derived from petroleum production.

The current UK petroleum taxation regime is complex and has arisen out of the many changes that have taken place since specific petroleum tax provisions were first introduced in 1975. The government has recently attempted to simplify the regime in order to make the UK more attractive for foreign investments, including the proposal to allow the assignment of tax history between incoming and outgoing licence holders (see detailed explanation in Section VIII).

Until the Finance Act 2016, there were three main elements of taxation: petroleum revenue tax, ring fence corporation tax and supplementary charge. Petroleum revenue tax (PRT) is a field based tax charged on profits arising from individual petroleum fields, but only in respect of those fields given development consent before 16 March 1993. PRT was originally levied at 50 per cent. On 16 March 2016, the Chancellor of the Exchequer announced a permanent reduction in the PRT rate to zero per cent with effect from 1 January 2016. PRT was not abolished in totality to allow for losses to be claimed back against past PRT payments (for example payments incurred as a result of decommissioning PRT-liable fields).

The two remaining elements of the tax regime are:

a ring fence corporation tax (RFCT): This is the standard corporation tax applicable to all companies with the addition of a ‘ring fence’, which prevents taxable profits from petroleum extraction being reduced by losses from other activities or by excessive interest payments. Deductions are available for items such as capital expenditure, plant and machinery, allowances, research and development and decommissioning. The main rate of corporation tax in the ring fence has been fixed at 30 per cent since 1 April 2008; and

b supplementary charge (SC): This is an additional charge on a company’s ring fence profits, introduced at 10 per cent on 17 April 2002. The SC was increased to 20 per cent in 2006 and 32 per cent in 2011. Following various fiscal reviews, the SC has been reduced a number of times and has been 10 per cent since January 2016. The concept of field allowances, which reduce the amount of adjusted ring fence profits on which the SC is charged, was introduced in 2009 to provide an incentive for the development of commercially marginal petroleum fields. These field allowances have now been replaced by a basin-wide investment allowance, which exempts a portion of a company’s profits from the SC. The amount of profit exempt from the SC is equal to 62.5 per cent of the company’s investment expenditure on the relevant field. Investment allowance is activated by generating relevant income (defined as production income from oil and
gas extraction activities). On 23 July 2018, the government published draft regulations that propose to expand the scope of relevant income to include tariff receipts (being income received for the use of infrastructure by third parties) for the purposes of calculating the SC. The amendments, if passed, are intended to encourage investment in infrastructure.

A new levy on offshore petroleum exploration and production licensees has been created to provide funding for the OGA. The levy is payable by licence-holders for each licence they hold. The levy is apportioned between pre-production licences (11 per cent) and producing licences (89 per cent), the latter being those licences where the OGA has given consent to start production. Details of the levy for 2018/2019 are set out on the OGA website and in The Oil and Gas Authority (Levy) and Pollution Prevention and Control (Fees) (Amendment) Regulations 2018.

VI ENVIRONMENTAL IMPACT

As well as being required to comply with all applicable laws, the model clauses generally require all licensees to operate in accordance with the methods customarily used in good oilfield practice and to take all steps practicable (a very wide concept) in order to prevent the escape or waste of petroleum (including into any waters in or near the vicinity of the licensed area).

The UK regulatory system for offshore installations is designed principally with accident and pollution prevention in mind. The main focus is to ensure that comprehensive measures are already in place so that an operator may anticipate any potential incident and act accordingly, rather than relying upon the authorities to dictate the appropriate response. The Merchant Shipping (Oil Pollution Preparedness, Response & Cooperation Convention) Regulations 1998, and the Offshore Installations (Emergency Pollution Control) Regulations 2002 (together the OPEP Regs) are the main components of the legal framework involving offshore installations. They impose obligations upon operators to implement robust emergency planning arrangements, and powers are reserved for the government to step in and take measures to enforce any necessary remedial actions. The Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (the OPPC Regs) and the Offshore Chemicals Regulations 2002 (the Chemical Regs) supplement the OPEP Regs by imposing a permitting system for oil and chemical discharges from an offshore installation, providing powers of remediation in the event of an unauthorised discharge, and providing powers to recover costs if the government has to intervene (should the operator fail to do so).

Following the Piper Alpha disaster and the Cullen Inquiry, the UK developed the Offshore Installations (Safety Case) Regulations 2005. The regulations require written safety cases and risk assessments to be prepared by the operator, and then approved by the Health and Safety Executive (the HSE), for all fixed and mobile offshore installations, before such installations are brought into use on the UKCS. The regulations also introduced:

a a system of well notification, where the HSE assesses well design and procedures;

8 Piper Alpha was a large North Sea oil and gas platform that started production in 1976. In July 1988 there was a leak of gas condensate that caused a massive explosion, leading to the death of 167 people.
9 Lord Cullen chaired the official public inquiry into the Piper Alpha disaster and made 106 recommendations within his report, all of which were accepted by the government.
b  a requirement for the design and construction of a well to be examined by an independent specialist;

c  a scheme of independent verification of offshore safety critical equipment (e.g., blowout prevention equipment) to ensure the equipment is fit for purpose;

d  checks to ensure workers have received suitable information, instruction, training and supervision; and

e  offshore inspections of well control and integrity arrangements, and related safety issues, by specialist inspectors from HSE’s Offshore Safety Division.

Under the Energy Act 1976 and the Petroleum Act, the consent of the OGA is required for flaring and venting. There are also a number of other regulations that relate to flaring of gases, gas turbines and other combustion plants, including the Offshore Combustion Installations (Pollution Prevention and Control) Regulations 2013 (the Combustion Regs) (amended in 2018 to extend to large combustion plant with an individual thermal input of at least 50MW, and medium combustion plant with an individual thermal input of between 1 and 50MW) and the Fluorinated Greenhouse Gases Regulations 2015.

The Offshore Environmental Civil Sanctions Regulations 2018 will come into force on 1 October 2018, allowing the Secretary of State to impose civil sanctions (by way of fixed and variable monetary penalties) on operators that breach several of the environmental regulations mentioned above (the OPEP Regs, the OPPC Regs, the Chemicals Regs and the Combustion Regs). The power to impose civil sanctions will apply to acts or omissions occurring on or after 1 November 2018, with the associated standard of proof beyond the threshold of reasonable doubt. The regulations require the Secretary of State to prepare and publish guidance about the new powers by 1 November 2018, and to publish reports from time to time specifying the cases in which penalties have been imposed.

In the aftermath of the Deepwater Horizon disaster in 2010, the European Commission adopted the Offshore Safety Directive (2013/30/EU) (the 2013 Directive), to address inconsistencies in the regulation of petroleum activities between EU member states and to set out certain minimum requirements that could prevent catastrophic events. There were three stages to the implementation of the 2013 Directive: (1) by 19 July 2015, member states were to bring into force any legislation necessary to comply with the 2013 Directive; (2) by 19 July 2016, legislation (implementing the 2013 Directive) would need to start applying to owners and operators planning installations and those planning and executing well operations; and (3) by 19 July 2018 the legislation would need to start applying to all existing installations.

The European Commission decided to follow, to a large extent, the UK’s highly respected environmental regime, and therefore many of the provisions of the 2013 Directive are already satisfied by the existing regulatory regime. However, a number of new laws were necessary to fully implement the 2013 Directive, including Offshore Installations (Offshore Safety Directive) (Safety Case etc.) Regulations 2015, Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015 and the Merchant Shipping (Oil Pollution Preparedness, Response and Cooperation Convention) (Amendment) Regulations 2015.

The 2013 Directive additionally required the creation of an offshore competent authority, which was established in the UK as the Offshore Safety Directive Regulator. The role of the Offshore Safety Directive Regulator is to supervise compliance with the 2013 Directive and undertake regulatory functions such as accepting, assessing, approving and
inspecting relevant safety cases, oil pollution emergency plans, well notifications and other notifications. BEIS retains responsibility for regulation and enforcement of the environmental regime.

The European Commission is currently assessing whether the 2013 Directive has achieved its objective of ensuring safe offshore oil and gas operations. The scope of the evaluation, as set out in an evaluation road map released on 3 May 2018, includes an assessment of gaps in safety legislation. The planned completion date for the evaluation is mid-2019.

In the event of an oil pollution incident in UK 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 such actionable wrongs as nuisance and negligence. The alternative and much more straightforward basis for recourse available to third parties, in the event of their suffering damage caused by operations of an offshore installation (including for onshore and offshore clean-up operations, property damage and certain other quantifiable losses), is to make a claim under the offshore pollution liability agreement (OPOL). All offshore operators currently active in exploration and production on the UKCS are party to this voluntary oil pollution compensation agreement. Operator membership of OPOL is a prerequisite condition of OGA granting a licence, so in practice, despite its voluntary status, membership of OPOL is unavoidable for operators. Under OPOL, operators are subject to strict liability (where proof of fault is not necessary) for pollution damage and the cost of remedial measures up to a maximum of (currently) US$250 million per incident.

VII DECOMMISSIONING

Decommissioning is primarily governed by the Petroleum Act, which imposes a clear requirement on licensees to pay for offshore installations to be properly decommissioned and completely removed from the seabed other than in exceptional circumstances. As noted above, BEIS retains responsibility for the regulation and enforcement of decommissioning obligations. Responsibility within BEIS rests with the Offshore Petroleum Regulator for Environment and Decommissioning (OPRED).

Section 29 of the Petroleum Act gives the Secretary of State the power to serve a notice (a Section 29 Notice) that either specifies a date by which a decommissioning programme is to be submitted (for each installation or pipeline) or, as is more usual, provides for a decommissioning programme to be submitted on or before such date as the Secretary of State may direct. The recipient of a Section 29 Notice must consult the OGA before submitting a decommissioning programme to the Secretary of State. The Petroleum Act requires the OGA to consider alternatives to decommissioning (such as reuse of the relevant installation), and to consider how to keep the cost of the programme to a minimum. Once the decommissioning programme is approved by the Secretary of State, the Section 29 notice holders are legally obliged to carry out the decommissioning programme on a joint and several liability basis. If they fail to do so, the Secretary of State may step in to carry out the work and invoice the Section 29 Notice holders.

In theory, the Secretary of State can serve a Section 29 Notice on a wide range of parties; not just the present licensees and operator but also anyone owning an ‘interest’ (which term is undefined in the Petroleum Act and therefore must be broadly construed) in an installation ‘otherwise than as security for a loan’ and associated companies (broadly
50 per cent, direct or indirect affiliates) of companies which are directly liable to have a Section 29 Notice served on them. The Secretary of State also has the power to withdraw Section 29 Notices (under Section 31(5)), for example, in respect of ex-licensees who have sold on their interest, but this is usually subject to the Secretary of State serving a Section 29 Notice on any incoming licensee and consulting other existing licensees. Crucially BEIS can reissue any notices withdrawn in this way (under Section 34) so the risk of (re)incurring liability for former licensees is never extinguished.

BEIS publishes guidance notes on the decommissioning of offshore installations and pipelines. BEIS released a revised version of the guidance notes in May 2018 (the Guidance Notes), providing further clarity and detail around decommissioning processes and the contents of a decommissioning programme. The decommissioning programme will set out and describe in detail the proposed measures to be taken and will include estimated costs, an inventory of materials including radioactive material, environmental impact assessment, a summary of the methods to be used to plug and abandon wells, a description of relevant installations, pipelines and materials on the seabed, removal of debris from the seabed and ongoing monitoring of the area after removal of the installation. The decommissioning programme will also tie in with related consents procedures under other applicable law. There are a number of possibilities for the items being decommissioned, including salvage, waste storage, carbon capture and storage, pipeline reuse and recycling. At the time of writing, section 12 of the Guidance Notes (on environmental considerations for decommissioning) had only been released in draft form.

The Secretary of State can ask for decommissioning security at any time with such security being ring fenced from creditors in an insolvency situation. The Guidance Notes state that OPRED has developed a financial policy, to be released in 2018, which will include the circumstances in which decommissioning security may be appropriate.

The increasing emergence of decommissioning security arrangements, as part of a sale and purchase agreement, resulted in the development of the Oil and Gas UK Decommissioning Security Agreement, which is now commonly entered into by all licensees. The agreements primary aims are to mitigate the risk of a party incurring ‘double security’, to allow a uniform approach to what is acceptable security (how much is required and when) and to reduce negotiation costs and lost management time. The agreement provides for decommissioning security to be held on trust by an independent security trustee. Decommissioning security may be put into the trust by way of cash (rare in practice), standby letter of credit, performance bond or insurance product. Annexure E of the Guidance Notes contains commentary on the minimum requirements for a decommissioning security agreement where the Secretary of State is to be a party. The commentary emphasises that security must be irrevocable, available on demand and issued by a UK body of substance. Parent company guarantees are not considered acceptable security, because (among other reasons) it could be argued that guarantees are not primary contractual obligations, resulting in litigation that could delay timely decommissioning.

OPRED is currently reviewing the decommissioning security agreement template, in light of recent low oil prices and new operators in the UKCS, so existing policy and guidance may change in the coming year. As noted above, OPRED is also due to publish a financial policy in 2018, which will focus on ensuring adequate funding and security are available for decommissioning costs on a field-by-field basis.

Tax is critical to the amount of decommissioning security that is required. Under the UK tax regime, a significant portion of decommissioning costs can be reclaimed,
when such costs are incurred, as a tax deduction in relation to RFCT, SC and PRT, where applicable (see further commentary at Section VIII). There have historically been frequent and unsettling changes to the UK tax regime, which created a fear among licensees, that when the total tax relief exceeded tax revenues, the government would once again change the rules. Decommissioning security agreements therefore required that security be posted on a gross basis, ignoring any tax relief. In 2013, in order to encourage investment, the government introduced the Decommissioning Relief Deed. The Decommissioning Relief Deed is a contract entered into by the government and individual companies under which the government protects the licensee from the following change in law: if the law changes after the enactment of the Finance Act 2013, such that the total tax relief achieved by the licensee is less than the amount of relief that would have been available had the law not changed, then the government will make a tax-free payment of the difference to the licensee.

VIII CURRENT DEVELOPMENTS

i Growth of decommissioning

One of the features of a mature basin is the fact that a large number of fields are near the end of their operational life. The decommissioning of smaller rigs has been under way for years as production began to decline, but a new wave of bigger projects is due to be decommissioned. The recent report by the OGA ‘UKCS Decommissioning 2018 Cost Estimate Report’ estimated the P50 cost of decommissioning at £55.7 billion in 2016 prices. Not all of this cost will be borne by the industry: through the tax relief mechanism the UK tax payer will incur more than half the cost of decommissioning. OGA has stated that its goal is to reduce its P50 cost estimate by 35 per cent from the 2017 estimate of £59.7 billion down to £39 billion. There are many ideas in the mix – the use of collaborative initiatives such as multi-operator well plugging and abandonment campaigns and sharing information among operators to create a more capable decommissioning supply chain. The government is also trying to bring new players into the game by allowing the tax relief for decommissioning to be attached to the asset rather than the licensee as it currently is (see below).

ii Transferable tax history and PRT post-transfer decommissioning expenditure

In March 2017, the government published a discussion paper titled ‘Tax issues for late-life oil and gas assets’. The paper identified two areas of the UK fiscal regime that may be preventing transactions involving late-life oil and gas assets. Both of these areas are now the subject of draft legislation, published for consultation on 6 July 2018. The proposed changes aim to extend the productive lives of late-life oil and gas fields, which should lead to delayed decommissioning and support increased investment in the UKCS. Both measures are to apply to the transfer of licence interests receiving OGA approval on or after 1 November 2018. The legislation is due to be finalised as part of the Finance Act 2018–19.

Transferable tax history (TTH)

Under the current regime, a licensee can offset some of its decommissioning expenditure against previous taxable profits. However, tax history attaches to the licensee who paid the tax, and cannot be transferred to an incoming licensee. As a result, the buyer of an interest in a mature licence may not be able to generate enough tax history to access tax relief at the time of decommissioning. The draft legislation addresses this issue by including a mechanism allowing the buyer and seller of a licence interest to make a joint election to transfer a portion
of the seller’s profits subject to RFCT and SC (together, the TTH) to the buyer. The draft legislation includes complex provisions around the amount of TTH that can be transferred, when the TTH will be ‘activated’ (when (1) production has permanently ceased; and (2) the buyer’s total decommissioning expenditure exceeds the total net profits accrued by the buyer) and ongoing requirements of the buyer to track the total net profits of the acquired interest.

**PRT post-transfer decommissioning expenditure**

It is common for sellers to retain liability for decommissioning under an agreement for the sale and purchase of a licence. Under the current regime, if the seller does not retain an interest in the licence, neither the seller or the buyer can claim a PRT deduction for decommissioning expenditure incurred by the seller or subsidised by the seller. This is because: (1) the seller can no longer lodge a PRT return as a ‘participator’ under the Oil Taxation Act 1975; and (2) the buyer cannot claim costs reimbursed by the seller because of restrictions on subsidised expenditure (which is disregarded for PRT purposes under Paragraph 8 of Schedule 3 to the Oil Taxation Act 1975 (the Anti-Subsidy Rule). This situation results in the need for complex and uncommercial arrangements for buyers to access tax relief. The draft legislation addresses this issue by: (1) treating expenditure incurred by the seller as having been incurred by the buyer; (2) treating expenditure subsidised by the seller as having been incurred by the buyer; and (3) disregarding the Anti-Subsidy Rule in both cases.

### The UK’s decision to exit the European Union (Brexit)

In general terms Brexit has made the allocation of capital in the UK a more difficult process than it already was, by creating a level of uncertainty in financial markets. This is equally applicable to the UK petroleum industry and its regulation, but there remains some uncertainty as to whether there will be a material impact in practice. The industry body Oil and Gas UK has listed a number of potential barriers to trade that may impact on the UK petroleum industry following Brexit, including increased tariffs, reduced mobility of labour, customs delays and additional regulatory burden. Other industry commentators suggest Brexit will have a more limited effect on the petroleum industry and this will, therefore, be a key area to watch in the coming years.
Appendix 1

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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, PFI, PPP 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.

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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.
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Djamila spent three decades at Sonatrach, where she held various responsibilities monitoring the implementation of upstream projects by negotiating more than
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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 (MCI Arb) 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.

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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.

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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 and the Portuguese Bar Association.

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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.

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Jubilee’s practice is focused in the oil and gas and LNG sectors, having advised state oil and gas entities, international oil and gas companies and financial institutions on a wide range of upstream and downstream acquisitions and developments, LNG development projects and offshore LNG projects. Jubilee is UK-qualified and has worked for leading law firms in London as well as in-house with oil and gas developers. In 2015, Jubilee was recognised in The Lawyer Hot 100 for her work in the energy sector. She was also recognised as a London Rising Star by Super Lawyers in 2013.

FELIPE FERES
Mattos Filho, Veiga Filho, Marrey Jr e Quiroga Advogados
Felipe Feres is a partner at Mattos Filho and concentrates his practice in oil and gas and mergers and acquisitions. He has previously worked at the New York office of DLA Piper LLP (US).

Felipe is licensed to practise law in Brazil and in the State of New York (New York State Bar Association). He holds a law degree from the Pontifical Catholic University of Rio de Janeiro (PUC-Rio), a postgraduate degree in Corporate and Capital Markets Law from the Getúlio Vargas Foundation in Rio de Janeiro (FGV-Rio) and an LLM degree from the University of Chicago.

Felipe was ranked by Chambers Latin America 2011, 2012, 2015 and 2016 as an associate to watch and in 2017 as an Up and Coming Lawyer in the oil and gas field. Felipe is also recommended by The Legal 500.

ANDRÉ DUARTE FIGUEIRA
Cuatrecasas
André Duarte Figueira has been a senior associate at Cuatrecasas since 2017. He is head of the firm’s oil & 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**

*Minter Ellison Rudd Watts*

Paul is a senior corporate and commercial partner and head of the energy and resources team at Minter Ellison Rudd Watts. 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”’.

**MANFRED FÜRNKRANZ**

*OMV Aktiengesellschaft*

Manfred has worked in the energy sector for nearly 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 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.

**NIKI GILL**

*McCarthy Tétrault LLP*

Niki Gill is an associate in McCarthy Tétrault’s corporate finance and mergers and acquisitions group in Calgary. Niki completed her law degree at the University of Calgary, prior to which she worked for a large oil and gas company in Alberta.
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 out of 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
Guanli Huang is an associate at Zhong Lun Law Firm.

CAMERON HUGHES
McCarthy Tétrault LLP
Cameron T Hughes is a partner in McCarthy Tétrault’s energy group and oil & gas group in Calgary with more than 20 years of experience working in the energy industry in Alberta. His practice focuses on mergers and acquisitions, energy infrastructure, project finance and development and joint ventures in the energy sector. He advises clients with respect to upstream, midstream and downstream issues, over-the-counter commodity trading, cross-border trading, energy derivatives, risk management, asset and payment securitisation and credit issues. Mr Hughes is recognised by Chambers Global: The World’s Leading Lawyers as one of Canada’s leading lawyers in energy: oil and gas.

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.

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. 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 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 generation, 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 chair of the oil and gas committee of the International Bar Association and on the board of the German-American Lawyer’s Association (DAJV).

YVES LEPAGE
Orrick, Herrington & Sutcliffe
Yves Lepage, partner in the Paris office of Orrick, Herrington & Sutcliffe, is the deputy leader of the energy and infrastructure business unit.

With 35 years’ experience in national and international energy and infrastructure projects, Yves Lepage regularly advises operators in both the public and private sectors, government entities and financial institutions in their operations in Europe, Africa and Latin America.

YING LIU
Zhong Lun Law Firm
Ying Liu ia a senior associate at Zhong Lun Law Firm.

GIOVANI LOSS
Mattos Filho, Veiga Filho, Marrey Jr e Quiroga Advogados
Giovani Loss is a partner at Mattos Filho and concentrates his practice in oil and gas transactions. He worked with Fulbright & Jaworski LLP in Houston for over three years and was seconded as lead E&P counsel to BG for six months in 2009.
Giovani is licensed to practise law in Brazil, New York and England (solicitor). He holds a master of laws degree from the University of São Paulo and an LLM degree from Stanford University.

An author of a book on natural gas regulation, Giovani is listed as one of the leading oil and gas lawyers in Brazil by Chambers Global 2011, Chambers Latin America 2012, 2013, 2014, 2015, 2016 and 2017, The Legal 500, PLC Which Lawyer?, as well as in Euromoney's Guide to the World's Leading Energy Lawyers. Giovani was the only Brazilian listed as one of the 'Top 10 Most Highly Regarded Oil & Gas Lawyers 2012 in the World' by Who's Who Legal, and, in 2018, Giovani was recognised as the Energy Lawyer of the Year by the same publication, the first and only Brazilian lawyer ever to receive such an honour.

JASON LOVELL
Eversheds Sutherland (International) LLP

Jason has an international corporate practice comprising a wide range of transactions and projects with a particular focus on the energy sector. His experience extends through the full length of the energy chain, including traditional oil and gas transactions, licensing advice, pipelines, shale gas, bio-methane projects and coal bed methane. Jason's oil and gas experience includes the provision of advice relating to the acquisition and disposal of upstream exploration and production assets in the North Sea; joint ventures in oil field services; the acquisition of onshore coal mine methane assets; advice on oil and gas licensing; disposals of natural resource assets and the representation of several private equity houses in their acquisitions of oilfield support services companies.

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.

NILTON MATTOS
Mattos Filho, Veiga Filho, Marrey Jr e Quiroga Advogados

Nilton Mattos is a senior associate at Mattos Filho and concentrates his practice in oil and gas and maritime transactions. He was seconded as legal counsel to BP for 12 months in 2011–12. He has previously worked at the London office of Freshfields Bruckhaus Deringer.

Nilton is licensed to practise law in Brazil. He holds a law degree from the School of Law at the Rio de Janeiro State University (UERJ) and an LLM degree from King's College London.
Nilton was ranked by *Chambers Latin America 2011, 2012, 2013 and 2017* as an ‘associate to watch’ and in 2014 as ‘up and coming’ in the oil and gas field and is recommended by *The Legal 500*.

**CURTIS MERRY**  
*McCarthy Tétrault LLP*

Curtis Merry is an associate in McCarthy Tétrault’s corporate finance and mergers and acquisitions group in Calgary. Curtis completed his law degree at the University of Western Ontario, prior to which he obtained a commerce degree from the Haskayne School of Business.

**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 has advised in disputes involving the prices demanded by generators in the wholesale market and regarding conditions for access to the grid and payment for use of an interconnector as well as a set-up regarding the sale of virtual power. 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 several oil and gas transactions, including for projects involving the North Sea.

**NATALYA MOROZOVA**  
*Vinson & Elkins LLP*

Natalya Morozova has been with Vinson & Elkins since 1991. She has been 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.


**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/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, metallics, 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 Petroleum Company of Trinidad and Tobago, the National Energy Corporation of Trinidad and Tobago, The National Gas Company of Trinidad and Tobago 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.

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.

CHRIS PASS
Eversheds Sutherland (International) LLP
Chris has several years of experience as an energy and resources lawyer, advising on petroleum and energy contracts, acquisitions and divestitures, joint venture and offtake arrangements, regulatory issues and procurement. Chris is qualified in Western Australia, having started his career at a leading independent law firm in Australia.

ROB PATTERSON
Vinson & Elkins LLP
Rob Patterson is an energy transactional lawyer, with a broad practice that includes cross-border mergers and acquisitions and the development and financing of energy and infrastructure projects. He has advised on a wide range of international transactions in the oil and gas, power, petrochemicals and LNG sectors. He has received recognition from
numerous publications, including most recently Euromoney (The World’s Leading Energy and Natural Resource Lawyers 2016), Chambers Europe (Energy and Natural Resources, Russia 2014), Chambers Global (The World’s Leading Lawyers, Energy and Natural Resources, Russia 2014, Energy & Natural Resources: China (Foreign Expert Based in United Arab Emirates), 2016 and 2017) and Who’s Who Legal of Energy Lawyers (2016 and 2017). Rob was co-administrative partner of the firm’s Moscow office from 2006 to 2010 and managing partner of the Beijing office from 2012 to 2013. He is currently based in V&E’s Dubai office, but divides his time between Dubai and Moscow.

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 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 & 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 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.

LUIZA SAVCHENKO

Vieira de Almeida

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.

CHRISTOPH SCHIMMER

DLA Piper Weiss-Tessbach GmbH

Dr 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 research and teaching assistant at the Institute for Tax Law at the University of Vienna.

JOÃO SEQUEIRA SENA

Cuatrecasas

An associate lawyer of Cuatrecasas since 2017, João Sequeira Sena was admitted to the Portuguese Bar Association in 2017.

He is a visiting lecturer on the introduction to law course at the Instituto Superior de Economia e Gestão, Lisbon, 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 honors in legal and political sciences (administrative law) from Universidade de Lisboa; João is preparing a thesis entitled ‘Administrative statement of nullity of administrative contracts’.

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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.

CHRISTOPHER B STRONG

Vinson & Elkins LLP

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

Hunton Andrews Kurth LLP

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 the 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

Cuatrecasas

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 professor at Universidade de Lisboa since 2011, 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 on the legislative reform of the oil sector concerning production, storage and transportation, and on the contentious-administrative reform in Guinea-Bissau as a member of the Law School of Bissau. He also advised on the Portuguese Cultural Heritage Act.

Having published several articles, Lourenço participated in legislative reform committees in Portugal and abroad. 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) and former vice-president of the Centre for Arbitration and Litigation at Universidade de Lisboa.

GUILLERMO VILLASEÑOR-TADEO

Sánchez Devanny

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

*DLA Piper Weiss-Tessbach GmbH*

Kenneth Wallace-Müller is 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.

JIHONG WANG

*Zhong Lun Law Firm*

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

*DLA Piper Weiss-Tessbach GmbH*

Dr Oskar Winkler 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.

ANJING WU

*Zhong Lun Law Firm*

Anjing Wu is an associate at Zhong Lun Law Firm.

JOSÉ V ZAPATA LUGO

*Holland & Knight*

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.

**DAHLIA ZAMEL**

*MENA Associates in association with Amereller Legal Consultants*

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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