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ACKNOWLEDGEMENTS

The publisher acknowledges and thanks the following law firms for their learned assistance throughout the preparation of this book:

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CGA – COUTO, GRAÇA & ASSOCIADOS
CMS
CROWLEY FLECK PLLP
CUATRECASAS, GONÇALVES PEREIRA
DLA PIPER WEISS-TESSBACH GMBH
GORRISSEN FEDERSPIEL
HOGAN LOVELLS BSTL, SC
HOLLAND & KNIGHT
KVALE ADVOKATFIRMA DA
M&PLAYNITSAS LAW OFFICES
MATTOS FILHO, VEIGA FILHO, MARREY JR E QUIROGA ADVOGADOS
MCCARTHY TÉTRAULT LLP
MENA ASSOCIATES IN ASSOCIATION WITH AMERELLER LEGAL CONSULTANTS
MINTER ELLISON RUDD WATTS
OMV GAS MARKETING & TRADING GMBH
ORRICK, HERRINGTON & SUTCLIFFE
PAPADOPOULOS, LYCOURGOS & CO LLC
SHEARMAN & STERLING LLP
Acknowledgements

SKRINE
STERLING PARTNERSHIP
UGHI E NUNZIANTE – STUDIO LEGALE
VINSON & ELKINS LLP
WEBBER WENTZEL IN ALLIANCE WITH LINKLATERS
WENGER & VIELI LTD
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2016 has been a year of flux for the international oil and gas industry.

With the industry enduring a second 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. Capital projects have been delayed or abandoned, staffing levels have been reduced, and oil companies have been seeking to sell off parts of their portfolios to focus on their best prospects and raise capital.

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. Although some producers with a relatively large ratio of reserves to population such as Kuwait, Qatar and the UAE have been able to get by without making drastic changes, others, such as Venezuela, have been brought to the brink of national bankruptcy as years of economic mismanagement enabled by high oil prices have finally taken their toll.

Yet amidst 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 managed to drastically improve the efficiency of their operations to survive, and even thrive, in the new price environment. And 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. Nowhere is this more evident than in the world’s leading exporter, Saudi Arabia, where the recently announced Vision 2030 Plan commits to reforms that would have been unimaginable just a few years ago. Not the least of which would be the potential public flotation of Saudi Aramco, the world’s largest company. Long considered to be the best-managed and most professional of the national oil companies, the additional rigour and transparency that would come from being publicly traded would bring significant changes and set an example for other national oil companies to follow.

The international oil and gas industry has always been cyclical. Although the last two years have been eventful, it is 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
November 2016
Chapter 1

ABU DHABI

James Comyn

I  INTRODUCTION

The United Arab Emirates (UAE) has a sustainable production capacity of 2.97 million barrels per day, making it the fourth ranked OPEC member. Ninety-five per cent of the UAE’s proven oil reserves are based in the Emirate of Abu Dhabi (Abu Dhabi or the Emirate), one of the seven emirates of the United Arab Emirates, and Abu Dhabi’s production accounts for almost all, if not all, of the oil exported from the UAE. The Emirate intends to increase its production of oil to 3.5 million barrels per day by 2018.

The UAE’s first oil agreement was concluded on 11 January 1939 between the then Ruler of Abu Dhabi and Petroleum Development (Trucial Coast) Ltd. This agreement covered the entirety of the Emirate, 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 was Petroleum Development (Trucial Coast) Ltd’s offshore rights in Abu Dhabi. Abu Dhabi entered into its second oil concession agreement on 9 March 1953, which concession covered offshore areas of the Emirate.

After a number of amendments, relinquishments and extensions, Abu Dhabi’s original onshore concession, often referred to as the ADCO concession as it was operated by the Abu Dhabi Company for Onshore Oil Operations, expired on 10 January 2014, 75 years after its

1 James Comyn is a partner at Shearman & Sterling LLP.
initial grant. Similarly, Abu Dhabi’s original principal offshore concession, operated by Abu Dhabi Marine Operations Company or ‘ADMA OPCO’, is due to expire in March 2018. The expiry and retendering of these two concessions are undoubtedly the most significant events in the upstream oil and gas sector of the UAE at the present time. The attractiveness of those concessions is enhanced by Abu Dhabi’s high reputation within the global oil and gas industry for political and economic stability.

This Chapter provides an overview of the legal regime in the Emirate of 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 United Arab Emirates 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 (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 Abu Dhabi National Oil Company (ADNOC) 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 set by it are accomplished;

b the SPC is expressly authorised to promulgate regulations in the petroleum field which the departments of the government of Abu Dhabi are required to implement and enforce;

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8 ‘The Oil & Gas Year’, page 11. All 43 respondents to a survey rated Abu Dhabi as stable or highly stable upon being asked to rate the level of political and economic stability in the Abu Dhabi oil and gas industry.

9 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.
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.\(^\text{10}\)

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

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

The principal legislation governing the 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 and with the prior consent of the SPC and to file monthly reports in respect of those activities.

**Treaties**

The United Arab Emirates 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 states, including China, France, Germany, Italy, South Korea and the United Kingdom, all states whose international oil companies (IOCs) or national oil companies (NOCs) have invested in the Emirate’s petroleum sector.

\(^{10}\) Abu Dhabi Law No. 1 of 1988 Concerning the Establishment of the Supreme Petroleum Council.
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;
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);11
e IOCs agree to maximise technology transfer to ADNOC and the operating company pursuant to 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 contracting 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 gas12 either

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11 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 which (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.

12 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.
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 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 agreements, to provide support to them pursuant to manpower supply agreements, 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 produced by them in the Emirate.

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 producing oil 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 VLCCs.13

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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. 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 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.

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 establish plans for dealing with environmental emergencies.

The Environmental Protection Law has the following objectives:

a the protection of the environment and the preservation of its quality and natural balance;
b the control of pollution and the avoiding of immediate or long-term damage or adverse impact on the environment resulting from economic development;
c the development of natural resources and the preservation of biological diversity within the UAE;
d the protection of human and animal health; and
e the implementation of the UAE’s obligations under international treaties relating to the protection of the environment, the control of pollution and the preservation of natural resources.

Title Two of the Environmental Protection Law deals with the protection of the aquatic environment – both the UAE’s coastal waters but also ground and drinking water. Article 18 prohibits the discharge of waste or polluting substances into the environment from onshore or offshore oil and gas fields unless preventative measure are in place and any discharge is treated in accordance with international practices.
Title Two of the Environmental Protection Law prohibits the discharge of oil, hazardous substances, sewage and waste into the marine environment. In the case of the discharge of oil from shipping, the owners of vessels and those operating them are liable for all expenses arising as a result of damage to the environment arising from an oil spill.

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

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

Articles 71 and 72 of the Environmental Protection Law imposes 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.

ii Role of ADNOC Environment, Health and Safety Division

The Environmental Protection Law envisages that its licensing provisions are dis-applied 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.

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14 See Article 94 of the Environmental Protection Law.
15 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.
17 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 or ‘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
The ADNOC HSE Code of Practice is supplemented by HSE Technical Guidance which is not mandatory but the relevant operator will need to demonstrate that any departure from the Technical Guidance is at least as effective as the approach recommended in the ADNOC HSE Technical Guidance.

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

VIII FOREIGN INVESTMENT CONSIDERATIONS

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

a. by establishing a branch or representative office which requires the foreign company to have a UAE national (or 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.18

The SPC and ADNOC also require oil companies who participate in the upstream oil and gas sector to establish a suitably staffed office in the Emirate.

In order 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

Abu Dhabi’s original onshore concession, often referred to as the ADCO concession, expired on 10 January 2014. The concession, in modified form, was re-granted with effect from 1 January 2015 with interests in the concession being granted to ADNOC (88 per cent), Total SA (10 per cent), Japan Oil Development Co, Ltd a subsidiary of INPEX Corporation (5 per

18 Article 10 of the UAE Federal Commercial Companies Law requires 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 which operate in oil exploration, drilling, refining, manufacturing, marketing and transmission provided that a provision dis-applying the UAE Federal Commercial Companies Law is contained in constitution of the company in question.
Abu Dhabi

Abu Dhabi’s original principal offshore concession, operated by Abu Dhabi Marine Operations Company, is due to expire on 8 March 2018, which raises the possibility that IOCs will be invited to participate in a tender process in respect of that concession. Interests in the ADMA concession are currently held by ADNOC (60 per cent), BP plc (14 per cent), Total SA, (13 per cent) and Japan Oil Development Co, Ltd (12 per cent).

Significant opportunities may also arise in the exploitation of Abu Dhabi’s gas reserves. Offshore, through the Abu Dhabi Gas Liquefaction Company Limited, a joint venture established in 1973 between ADNOC (70 per cent), Mitsui & Co Ltd (15 per cent), BP plc (10 per cent) and Total SA (5 per cent), ADNOC has been exporting LNG to the Far East. It is understood that these arrangements may shortly be falling for renewal. In addition, the Emirate’s reservoirs are known to contain vast reserves of gas, albeit with a high sulphur content. The Emirate is understood to be considering how best to exploit these reserves.

20 http://www.thenational.ae/business/energy/door-is-still-open-for-adco-concession.
I INTRODUCTION

With a land area of 83,879km² and a population of approximately 8.6 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, in 2014 domestic natural gas production was 45,427 petajoules (PJ) (1,291.64bcm), and 348,073PJ (9,896.87bcm) was imported and 82,909PJ (2,357.38bcm) was exported. In the same year, domestic oil production was 38,796PJ (1,103.1bcm), and 325,672PJ (9,259.94bcm) was imported and no significant quantities were exported. Austria therefore relies heavily on oil and gas imports, primarily from Russia.

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.

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

II LEGAL AND REGULATORY FRAMEWORK

Due to its size and administrative structure, Austrian energy legislation is fairly comprehensive, with one central act regulating oil and gas exploration and production as well as general mining activities at the federal state 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 III of the Federal Ministry Economy, Family and Youth (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 with the upstream sector.

i Domestic oil and gas legislation

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

Owing to its membership of the European Union, Austria has had to implement a number of directives that apply to the upstream energy sector. The Oil and Gas Licencing Directive, which aims to ensure non-discriminatory access to oil and gas exploration and production, was implemented in Austria under the Federal Procurement Act 2006.

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\(^2\) and the Gas Statistics Regulation 2012\(^3\).

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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\(^2\) Federal Law Gazette (Bundesgesetzblatt) II No. 226/2011.

\(^3\) 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, 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) have a 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, Russia, 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. Austria has additionally entered into bilateral agreements with both the Czech Republic and Slovakia 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 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.

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5 Regulation (EU) No. 1227/2011 on wholesale energy market integrity and transparency.
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 of Finance, in return for an ‘appropriate’ consideration. This consideration comprises either an ‘area interest’ for exploration or a ‘field interest’ and ‘production interest’ for production (including the right to acquire the oil or gas produced) for the duration of the transfer. Pursuant to Section 69(1) of the Mineral Resources Act, this consideration may, however, be suspended when deemed necessary to (1) avert a macromconomic 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 rightsholder is the submission of a work programme for approval by the Ministry in accordance with Section 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 landowners 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 to Section 10 of the Air Pollution Control Act 1997.
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.

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) 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), E-Control.

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 which 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

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11 As established by the E-Control Act.
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.

Imports and exports of oil are regulated by the Oil Stockholding Act. Whilst 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 supra, the exploration and production of oil and gas within 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 such 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, as amended, and subject to corporate income tax.

According to Section 7 of the Corporate Income Tax Act, the tax base for the corporate income tax is the yearly income of the corporation. The starting point for the calculation of the taxable income is the profit according to the external accounting under the provisions of the Austrian Commercial Code. In the course of the calculation of the taxable income, the profit according to the external accounting is adapted with increases and reductions to meet the requirements of the provisions of the tax law. Such adaptations 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.

ii Value added tax

Corporations trading in oil and gas are considered entrepreneurs within the meaning of Section 2 of the Value Added Tax Act 1994. The provisions of supplies or services in the exchange for a consideration performed in Austria by such entrepreneurs in general are subject to value added tax (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 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, operations involving the production of oil and gas must undergo an environmental impact assessment by the Ministry if their production exceeds certain thresholds. Pursuant to point 27 of Annex 1 of the Environmental Impact Assessment Act, these thresholds are either when the production of oil exceeds 500toe/day per probe or when the production of gas exceeds 500,000m³/day per probe. A simplified assessment procedure is to be performed if production is carried out in protected areas either when the production of oil exceeds 250toe/day per probe or when the production of gas exceeds 250,000m³/day per probe.

In addition to the above-listed criteria and approvals, rightsholders 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 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 which are involved in energy supply require approval by the Ministry.

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

ii Capital, labour and content restrictions
Capital and labour from EEA countries or Switzerland into Austria is 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 the EEA or Switzerland – must apply to the Public Employment Service for either a ‘posting permit’ for workers posted up to four months, or an ‘employment permit’ for periods lasting over four months.

In any case, a visa is required for posts of less than six months, and for those with posts exceeding six months a ‘posted worker stay permit’ is required. In order to receive this, in accordance with Section 59 of the Settlement and Residence Act 2005 the worker must fulfil the criteria listed in Part 1 of the Act, and provide confirmation of guaranteed work in accordance with Section 18 of the Employment of Foreign Nationals Act 1975 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.

Anti-corruption measures are primarily regulated in Sections 302 to 313 of the Austrian Criminal Code, whereby such corruptive practices are generally punished by imprisonment from 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) 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.

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

In September 2016, OMV sold 49 per cent of its stake in its (formerly) wholly owned subsidiary Gas Connect Austria (GCA), one of Austria’s two gas transmission system operators, to a Consortium composed of Allianz (Europe’s largest insurer) and Snam (the Italian gas grid operator). The consortium was selected as purchaser after a competitive auction process. OMV will retain a controlling stake of 51 per cent in GCA. The closing of the transaction is expected by the end of the year 2016.

At the end of September 2016, OMV announced that it would drill a further 12 probes in the Weinviertel in Lower Austria in 2017, 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 years, and are expected to ensure OMVs national production rates at its 2015 rate of 32,000 barrels per day.
I INTRODUCTION

Nineteen 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 2014, Brazilian proven oil reserves increased 3.6 per cent in comparison with 2013, representing 16.2 billion barrels of oil. The country is ranked 15th among the world biggest proven oil reserves. National oil production reached 2.437 million barrels per day in 2015, and the production of pre-salt totalled 1.091 million of barrels of oil equivalent per day, volume 33.7 per cent higher than December 2014. The country is ranked ninth among the world’s biggest oil producers. As regards liquefied natural gas (LNG), production rose 10.19 per cent in comparison with 2014, hitting 96.2 million cubic metres 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. Also, currently the government is preparing the 14th licensing round, scheduled to take place in 2017, and a second 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

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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.

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 as 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 Petrobras and PPSA;
- minimum requirements for the unitisation, according to the ANP’s regulations; and
- government takes for the PSA.

ii  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

\(^2\) Recently a bill was approved in the Brazilian Senate to alter the wording of the Pre-Salt Law, ending Petrobras’ mandatory minimum stake as well as its mandatory operatorship in the Pre-Salt area. The bill is still pending approval by the Brazilian Congress and the President (as further addressed in detail).
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.

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.

### 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 No. 8,003 of 15 May 2013, which put in force a TIEA entered into with the United States.

### LICENSING

From the end of Petrobras’ 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:

\[ a \quad \text{signature bonus: a lump sum payable in a single instalment upon execution of the concession agreement or PSA;} \]

\[ b \quad \text{minimum work programme; and} \]

\[ c \quad \text{local content.} \]

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.

The current PSA regime provides that Petrobras will be the sole operator with a minimum 30 per cent participating interest in the consortium to be awarded with the PSA, with the remaining percentage being contracted with other companies through competitive bidding rounds. However, this system is likely to be altered, possibly even before the next bidding round for pre-salt areas.

Recently, a bill that proposes to end Petrobras’ mandatory operation and minimum stakes in the pre-salt area was approved in the Brazilian Senate and it is expected to be voted until the end of 2016 in the Congress. In case it is approved in the Congress, the bill will still be subject to presidential approval. If approved, it will alter the wording of the Pre-Salt Law, replacing the current system for one where Petrobras will have preferential rights for the operation and minimum stakes of each pre-salt area to be offered in a bid round.

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.
Petrobras (as the operator) and 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.

Anti-competitive 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.

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.

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;
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

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 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 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 correspond environmental assessment:

\( a \) 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;

\( b \) 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

\( c \) 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. 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 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.

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 for one-third of foreign employees in the company (which includes the headquarters and each branch with more than three employees). Such 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 investment 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

Important regulatory and legislative developments are taking place in Brazil, given the current difficulties faced both by the O&G industry, and by several Brazilian states and cities.

At the request of state governments wishing to increase revenues in the crisis period, ANP called public consultations to revise the criteria for calculation of payments of Royalties (government’s mandatory participation in production results). A new resolution modifying the minimum price to be considered for calculation of Royalties was about to be published when the CNPE intervened, publishing a resolution prohibiting ANP from changing the existing criteria, mainly because of claims from members of the industry that it would further destabilise their financial situation in the context of the sector crisis by raising production costs. The dispute went to the courts, with the states’ governments demanding that the Supreme Court declare the CNPE’s resolution unconstitutional and prevent any further interference on the matter by the Council. The Court partially granted the request, deciding that in fact the resolution was unconstitutional, but scheduled a conciliation hearing for all parties to discuss and decide together on the criteria. The final chapters on whether the royalties policy will be altered or not are yet to happen, so changes can be expected.

As to the local content policy, it is important to mention that, although originally created to foster the national industry, the local content obligations are no longer being an incentive in this regard. For this reason, the federal government recently created the PEDEFOR (Programme to Stimulate Competitiveness of Supply Chain, Development and Supplier Enhancement of Oil and Natural Gas Sector), that seeks enhancement of local content policies of the exploration and production of oil and natural sector gas through the legal recognition and appreciation of initiatives and investments that contribute to raising the competitiveness of suppliers in Brazil. As players are not achieving the minimum percentages and penalties are becoming more and more common, the PEDEFOR intends to consider alternative initiatives and investments taken by operators that develop the internal suppliers market for compliance with the local content percentages through a special committee formed by members of the Ministry of Mines and Energy, CNPE and ANP, that will assess the presented initiatives and investments and their value as local content percentages. The PEDEFOR is yet to start functioning effectively, as it depends on the formation of a special committee. Accordingly, it is expected that the ANP will soon revise the local content rules not only making changes to the applicability of penalties but also considering a bonus scheme for those players complying with the local content commitments.

Also, the ANP enacted a new resolution reviewing the ANP Ordinance No. 170/1998. The ANP Resolution 52/2015 now sets the rules for the construction, expansion and operation of handling facilities of oil, oil products and natural gas, including LNG. Among the changes made by the new resolution, we highlight the regulation of the construction,
expansion and operation of facilities or production flow and transfer pipelines associated with the exploration and production of oil and natural gas that are not part of granted E&P areas. The facilities covered by the resolution include all systems essential to their operation, such as pumping stations, storage tanks, compressor stations, delivery or receiving points of natural gas, and measuring stations for operational purposes or transfer of custody, among others.

The ANP has also enacted Resolution No. 11/2016, which regulates the open access to natural gas transportation pipelines, swap of natural gas, rules for assignment of rights and obligations under a gas transportation service for firm transportation; procedure for registration of such transportation contracts with ANP and new public call procedure for contracting natural gas transportation capacity with transporters (as open access is applicable to transportation and transfer pipelines). Moreover, this new resolution comes in light of ANP Resolution No. 51/2013, which promoted the deverticalisation of the gas transportation sector by imposing a restriction on cross-ownership: companies or consortia that are concessionaires of natural gas transportation pipelines (transporters), or that have a participating interest in those companies are prevented from requesting authorisation for performing natural gas shipping activities.

Although not directly related to the regulation of the oil sector, it is important to highlight Petrobras’ current situation. As a result of an investigation being carried by the Brazilian Federal Police, known as Operation Car Wash (a reference to money laundering), many directors of Petrobras and its contractors were arrested. Pursuant to the investigations, the individuals involved have supposedly embezzled millions from contracts entered into by Petrobras and contractors. As a consequence, Petrobras has suspended several contracts, impacting the Brazilian oil and gas industry negatively. The investigation affected various companies in the oil and gas chain, and may even present good opportunities for investors to acquire the assets or even the companies themselves as certain players are selling some of their projects and participating interests to retain the cash needed for their investments and for reorganisation.

In addition to Operation Car Wash, Petrobras’ financial problems, caused by falling oil prices, its high indebtedness, and the cut in its ratings, has led Petrobras to promote its divestment plan. One of the main divestment items is the sale of multiple downstream and midstream companies it owns. Despite some initial resistance in courts, the sale of Gaspetro and Liquigás, both subsidiaries from Petrobras, are near completion. Not only may this represent some great opportunities for players looking to invest in Brazil, but its importance is even greater for the Brazilian oil and gas market, as currently Petrobras has a de facto monopoly over these sectors. The divestment of its participation in the gas transportation pipelines forced both Petrobras and the federal government to seek out solutions for this issue – as Petrobras is currently the sole owner of the gas transportation network. In response to that, the Ministry of Mines and Energy has disclosed a new plan that may be freely translated as ‘Gas for Everyone’, which aims to increase the share of the natural gas in the Brazilian energy mix. This plan includes the participation of private agents and associations in the discussion on how to improve the market conditions for the natural gas, including the possible creation of a central authority to control the movement of gas through the network (similar to other authorities in Europe). The overall expectation is that these divestments, together with the new rules to be enacted by the ANP, will open these sectors to new players, leading to a competitive market and promoting new investments.

The divestment plan also includes plays in areas on production and exploration phases. Recently Petrobras sold to Statoil the BM-S-8 block, including the Carcara discovery, for
US$2.5 billion. By the end of the year, Petrobras forecasted divestments that total US$15.1 billion for the biennium 2015–2016. As a result, for new sales and negotiations planned for the following months, E&P companies are looking into the opportunities of the exploratory blocks offered in the next bidding rounds, and in Petrobras’ assets.

Finally, the federal government is expected to carry at least three more bidding rounds until the end of the next year. These bidding rounds will include opportunities for all players in the market, as there will be onshore, offshore and even pre-salt areas being offered. The overall expectation of the market is that there will be some changes to the contract’s framework to attract more investments into such round, avoiding another ‘fiasco’ such as the 13th bid round carried in 2015. However, no further information on these changes have been disclosed so far.
Chapter 4

CANADA

Craig N Spurn, Kristen Haines and Curtis Merry

I  INTRODUCTION

Canada is endowed with substantial oil and natural gas resources. Over the past 150 years Canada has become a leading producer and supplier of oil and natural gas with Canadians becoming among the most skilled people in the world at extracting, processing and transporting conventional and unconventional hydrocarbons.

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 that allowed drillers to access vast quantities of crude oil, the oil boom took hold in the US 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 that they took with them to the more 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 by accident in 1866. Drilling for water near Medicine Hat, Alberta, a Canadian Pacific Railway crew encountered natural gas. Soon, further wells were drilled and more gas was discovered. Further natural gas discoveries were made in southern Alberta in the early 1900s and pipelines began to be constructed to move the gas to larger population centres.

Oil was also being discovered in significant quantities in 1914 at Turner Valley, Alberta, in 1920 at Norman Wells in the North West Territories and again at Wainwright, Alberta in 1923. It was not, however, until 13 February 1947 that Canada emerged 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

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history and led to a number of significant exploration successes in both oil and natural gas in the 1950s to 1970s. These developments 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 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 oilsands 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 improving the economics of producing bitumen from the oilsands, 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 this development and investment came international recognition of the oilsands 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 the impact of these plays has had a dramatic impact on crude oil prices, regional natural gas prices and supply and demand trends, as discussed further below in the current developments section. As the US domestic production 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, although in the province of Quebec a Civil Code governs such matters. The provinces have jurisdictions over local matters including the exploitation of natural resources, such as oil and gas, while the federal government is responsible for national and international matters including 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, falls, with certain exceptions, to the provincial governments, 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 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;
Canada

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>Environment Assessment Act</td>
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<td>Alberta</td>
<td>Ministry of Energy</td>
<td>Mines and Minerals Act</td>
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<td>Alberta Energy Regulator</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>Manitoba</td>
<td>Ministry of Innovation, Energy and Mines of</td>
<td>Oil and Gas Act</td>
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<td>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 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) on the other hand, 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 of several major trade and investment protection agreements, including the World Trade Organization, the North American Free Trade Agreement and the Canada-European Union Comprehensive Economic and Trade Agreement. 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). Canada is also a signatory to the Trans-Pacific Partnership. The legal review of the Canada and European Union Comprehensive Economic and Trade Agreement was also completed on 29 February 2016. This agreement will come into effect once the process required to approve the agreement in Canada and the EU is completed.

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 achieve 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 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 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 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. 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. However, 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 certain restrictions regarding the type or extent of oil and gas activities which can be undertaken, generally there are no explicit statutory or common law restrictions on production in Canada. Restrictions on activities, such as through the use of spacing units to limit the number of wells that can be drilled on an area of land, 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 whether the substance proposed to be exported exceeds the surplus after taking into consideration 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 Income Tax Act and taxable income
Corporate income taxes are imposed at the federal and provincial/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. In 2015, the highest combined income tax rate applied to a non-Canadian controlled private corporation was approximately 31 per cent, while the lowest was approximately 25 per cent. 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 recently proposed to implement a national carbon tax, setting a minimum surcharge on carbon-based fuels, in an effort to meet international commitments on the reduction of greenhouse gases. If implemented, the federal programme would complement provincial carbon pricing programmes currently in force in British Columbia, Ontario, Quebec and, most recently, Alberta. In particular, Alberta’s Climate Leadership Implementation Act applies a carbon levy effective 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 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.

iv 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 which they authorised or directed.

v 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

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2 See, for example, the Canada–British Columbia Agreement on Environmental Assessment Cooperation (2004) and the British Columbia Memorandum of Understanding on the Substitution of Environmental Assessments.
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 the 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 additional security deposits to be paid to offset the possibility that a party will be unable to fund future remediation obligations. In particular, on 20 June 2016 the Alberta Energy Regulator released a new interim bulletin requiring buyers of oil and gas assets to achieve a post-transfer LLR of 2.0 (as opposed to the usual 1.0 requirement) in order for well and facility licences applicable to the purchased assets to be transferred to the new owner. This new requirement, although temporary, has resulted in uncertainty in the industry, as many buyers are unable to meet the new LLR transfer requirements, and buyers and sellers alike remain wary of further changes by the various regulators to the LLR programmes.

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 (ULC) as a vehicle for their business activity in Canada to take advantage of favourable treatment afforded to ULCs as flow-through entities under US tax law.

Unlike a corporation, a partnership is not a separate legal entity from its owners. It is a business organisation comprising 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 partner's 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 limited 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
Canada

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 prime 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 (a state-owned enterprise), 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 oilsands 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$87 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. 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. To date the government has successfully prosecuted four Canadian companies and it is estimated that there are approximately 12 active investigations. 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
The Canadian oil and gas industry is currently under significant financial hardship, as evidenced by the tens of thousands of job terminations at energy companies and the loss of billions in capital spending. Among other challenges, low commodity prices, lack of access to international markets and competing international resource developments all contribute to a difficult economic climate in Canada.

In particular, oil prices in Canada have fallen by more than 50 per cent since 2014. Although there are many factors at play, generally, the price drop is a result of a supply glut and faltering demand. On the supply side, the United States, traditionally an anchor market for long-standing oil suppliers, and the main international customer for Canadian producers,

boosted its national production through shale oil plays. At the same time, the OPEC nations, traditionally swing producers who took oil off the market to respond to oversupply, abandoned their role as such, increasing supply as demand faltered. This move was seen by many as an attempt by the OPEC nations to maintain their market share by driving the price of oil down, given the comparatively low cost of producing their oil. Additionally, certain markets with offline production due to security issues and embargoes, such as Libya and Iran, came back onto the market resulting in even more supply. Meanwhile, on the demand side, faltering demand was, in part, a product of a shaky Chinese economy combined with diminishing demand from the United States as it moves towards energy independence. The result of the above-described oversupply and under-demand is a change in the traditional dynamics between the world’s oil supply and demand centers, and one that continues to play out in the energy industry as a whole.

Despite these issues, the oil and gas industry remains a significant and important part of the Canadian economy. Moreover, Canadian producers have responded to the low oil prices by embracing new innovative technologies, improving efficiencies and lowering production costs, setting the stage to ensure that Canada remains a global force in the oil and gas industry.
I INTRODUCTION

In 2015 and 2016 governmental agencies in Colombia have been analysing how to adapt to the current oil and gas context, particularly in relation to unconventional reservoirs, measures to prevent a crisis as a result of the downswing in oil prices and investment promotion. Only eight exploration wells were drilled in Colombia in the first quarter of 2016. Compared with the nine wells drilled in 2015 in the same period, the variation percentage is 11.1 per cent. This fact 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. The National Hydrocarbons Agency (ANH) is still in debt as a result of providing structural reorganisations to reactivate the oil and gas industry.

On the other hand, the advancement of the peace process, and the referendum that was voted on this October may increase investors’ appetite for developing their business in Colombia; however, if the ANH does not provide a consistent legal framework, considering the current petroleum situation, Colombia will lose a unique opportunity to boost its economy derived from oil and gas activities among others. Evidently, final approval of the peace process will determine whether or not investors gain greater interest in Colombia. 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

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of the ANH and converted it into a state agency); and (2) the transformation of the legal nature of Ecopetrol into a corporation dedicated exclusively to the upstream and downstream business inside and outside Colombia.

With that changes, Colombia started to be a more competitive state as Ecopetrol became another competitor in the market, leaving to the ANH the sole regulatory and administrative management of hydrocarbons. However, since 2014, exploratory activities have been in steady decline. Reaching a definite agreement for the peace process in Colombia may mitigate this decline, but it is important to note that referendum results must be favourable to enact the agreement reached by the government and guerrilla forces.

It is expected that reactivation of exploration activities increase after peace process finalises, but numbers indicate the opposite. In 2015 a total of 26 exploration wells were drilled in Colombia, compared with the eight wells drilled up to May 2016. Additionally, seismic exploration done in 2015 covered an area of 32,680km, while in 2016 no seismic exploration has been made to date in 2016, considering the information provided by the ANH.5 Oil reserves in 2015 were estimated at 2,002 billion oil barrels, but if exploration and production activities continue to decrease, it is expected that reserve levels will decline as well.

In 2015, average oil production was 1,006kbpd, while in 2016 average oil production for the first semester is 928kbpd.6

Regarding gas production one can detect a minor increase in the first semester of 2016, confronting the 1,133 million cubic feet per day produced in 2015 against the 1,158 million cubic feet per day produced through June 2016.7

There are still changes that need to be incorporated as to the government take in production alongside competitive and flexible contractual terms, promotion of offshore activities, interest and awarding of contracts for unconventional plays, and legal security regarding communities and social factors (prior consultation procedure and the veto power).

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.8 Similarly, the basis for royalties is constitutionally defined by establishing that any production of non-renewable natural resources shall entail a royalty in favour of the state in addition to any further right or compensation that is agreed to.9

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6 www.anh.gov.co/Operaciones-Regalias-y-Participaciones/Sistema-Integrado-de-Operaciones/Paginas/Estadisticas-de-Produccion.aspx.
7 www.anh.gov.co/Operaciones-Regalias-y-Participaciones/Paginas/Sistema-Integrado-de-Reservas.aspx.
8 Article 332 of the Colombian Political Constitution.
9 Article 360 of the Colombian Political Constitution.
As to the underlying titles or agreements that allow for the exploration and exploitation of hydrocarbons, Colombian regulations refer to (1) association contracts (the association agreements) still in effect with Ecopetrol; (2) the technical evaluation agreements (TEAs); and (3) exploration and production contracts (E&Ps) entered into with the ANH. These various forms of contractual agreements allow any party to develop its activities in the oil and gas sector. As to the regulations in place for the development of hydrocarbons activities, rules have been issued essentially by the Ministry of Mines and Energy while the ANH has defined particular rules for TEAs and E&Ps in its condition as a state agency in charge of executing these contracts with the corresponding participants. A final set of rules are those that regulate environmental and social conditions for the development of operations in oil and gas. One must remember the various timelines that each of these sets of regulations entail and the manner in which exploration and production activities must be completed.

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

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

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, regulatory framework includes norms, technical rules, structure regulations and historic norms.

Framework regulations are essentially found in the Petroleum Code. While various aspects of the 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 recognition by which the petroleum industry is considered of public interest in aspects of exploration, production, refining, transport and distribution, is a matter of relevance. Also, all data obtained during the course of scientific, technical, economic or statistical activities must be provided to the Colombian government, as part of the duties that parties involved in the oil and gas industry must abide with. Aspects relating to contracts, royalties and fines have since been updated by further regulations.

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10 Decree 968 of 18 May 1940.
11 Article 4 of Decree 1056 of 1953.
12 Article 7 of Decree 1056 of 1953.
Technical rules that were contained in the Petroleum Code have also been updated. Decrees 70 of 2001 and 3724 of 2009, granted regulatory powers to the current Ministry of Mines and Energy. Accordingly, Resolution 181495 of 2009 was issued. This Resolution fully comprehends the main regulatory framework for the exploration and production of hydrocarbons with the purpose of maximising their recovery and avoiding waste. Resolution 181495 (updated by Resolution 40098 of 2015) establishes that the Ministry of Mines and Energy is in charge of all activities regulated in the norm, issuing any technical rules and administrative decisions associated with the regulation, and imposing applicable sanctions for breaches thereof. Regulated operations are expected to comply with national and international standards, including in particular AGA, API, ASTM, NFPA, NTC-Icontec, Retie or similar as found in the petroleum industry. The resolution recognises that it is subject to all such regulations pertaining to environmental protection and sustainability as well as consultation requirements with communities, health and safety requirements, and labour conditions defined under the ILO Agreements 174 and 181. Parties to an underlying agreement must understand the particularities of the definitions found in Resolution 181495. Colombian law is strict in defining terms and conditions, which when not clearly understood or applied by the interested party can lead to breach of obligations or loss of rights under the underlying agreement. This rigidity has been compounded by the many agencies with oversight over public agencies and officials. The system consists of a prior authorisation and reporting structure. Any activity or operation to be undertaken by the operator of record under an oil and gas contract requires the due filing of documentation and forms before the Ministry of Mines and Energy for them to approve and control activities development under the contracts. There have been recent attempts to simplify this system, easing the operational burdens for contractors. However, the system seeks to ensure that rules are fully respected and that expected activities by an operator are fully undertaken.

In 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 Colombian 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 0421 of 2014 from the Ministry of Environment and Sustainable Development and the set of rules and contract drafts for unconventional reservoirs issued by the ANH in

13 Article 1 of Resolution 181495 of 2009.
14 Article 4 of Resolution 181495 of 2009.
Agreement No. 3 of March 2014. Note must be made that the Ministry of the Environment has already issued terms of reference for the exploration of unconventional reservoirs, but 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, recognises that the transport of crude is a public service, which implies that parties undertaking such activity must operate in accordance with regulations applicable to public utilities. After many years of discussion as to whether or not public access was to be granted to oil pipelines, the regulation to ensure free access to parties without any form of discrimination was granted in accordance with the Petroleum Code, defining a set of fair and reasonable transport principles and prices. In furthering the principles of the Code, the government’s preferential right in the transportation of hydrocarbons was reiterated. This right, which is held by the government and exercised through the ANH, in relation to the capacity of the oil pipeline is defined for public pipelines in terms of the right of transport of state crude and with respect to private pipelines for royalty crude. This right extends to 20 per cent of the calculated capacity of the pipeline as constructed. Another aspect that merits comment is the fact that Resolution 72145 required transporters to issue a manual for transportation and to make such manuals public. Transportation manuals must 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. There is an expectation of growth in more than 200km during 2016.

ANH is currently in charge of administrating TEA and E&P contracts, leading to considerations of contract rules. As of 2004 and until Agreement 04 of 2012 was issued by the ANH, Agreement 008 of 2004 defined rules pursuant to which a participating interest in such contracts could be held; contract rules; and how to evidence capacities required to be a contractor under an oil and gas contract. As of 2012 the new Agreement 04 updated these rules to include in particular a new standards and international principles for certain types of operations. While the ANH is empowered to enter into direct contracts with interested investors, over the last 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

15 Article 212 of Decree 1056 of 1953.
16 Article 47 and following of Decree 1056 of 1953.
17 Article 196 of Decree 1056 of 1953.
environment, were 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 regulatory body empowered to ensure operational aspects post-upstream chain:

- in 1999 Resolution 071 defined the Unique Technical Rules for the Transport of Natural Gas;
- 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
- in 2015 three key resolutions, 041, 062 and 089, regulated the methodology to calculate the cost of non-exported natural gas, the income for imported natural gas in security generation scenarios, and regulated commercial aspects of the wholesale market of natural gas, respectively.

ii Regulation

The Ministry of Mines and Energy is the principal government body in charge of regulating upstream operations in oil and gas. At the contracting level in oil and gas, and other than such association agreements that Ecopetrol held as of 31 December 2003, all subsequent contractual arrangements are executed by the ANH. The ANH’s powers are defined under Decree 1760 of 2003, which created the ANH, and are further developed by Decree 4137 of 2011. While in certain matters there may be doubts as to the delimitation of powers of the Ministry and the ANH, it is clear that the fundamental regulatory powers lie with the Ministry and the ANH is merely an administrator of the non-renewable resources to be developed via TEAs or E&P contracts. As a relevant matter, in early 2013, the ANH and the Ministry executed an inter-administrative agreement that delegated to the ANH certain fiscalisation 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 permitting, 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 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 in the area of the project in first instance, but as the project develops, they appear as affected stakeholders. This situation causes a major delay in operations when no agreement is reached with emerging communities, since the courts’ position gives such communities the right of prior consultation, even though certification of no-presence have been issued by competent authorities. The matter is treated by the constitutional court in the judgment T-382/06.19

iii Treaties

With the issuance of Law 3920 in 1990, Colombia became a party to the 1958 New York Convention.

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

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

a the Free Trade Agreement between Colombia and Peru on the one hand and the European Union and its Member States as approved by Law 1669 of 2013;
b the Free Trade Agreement between Mexico and Colombia as approved by Law 1457 of 2011;
c the Free Trade Agreement between Canada and Colombia as approved by Law 1363 of 2009; and
d the Free Trade Agreement between Colombia and the United States of America as approved by Law 1143 of 2007.

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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.

iv 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 4 of 2012 (as further modified). 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 4 of 2012. 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 4 of 2012.

In accordance with Agreement 4 of 2012, interested parties must meet the five minimum capacity requirements: legal; financial; technical-operational; environmental; and social responsibility. Legal capacity can include time of existence and corporate purpose definition. Financial capacity relates to the economic solvency that an investor is expected to have in order to comply with its obligations under the corresponding agreement. The technical and operational capacity of the proponent is tied to production and reserves of proponent, including the technical team available to undertake the proposed contractual commitments. The environmental capacity refers to a set of principles, rules and best practices to which the proponent commits and is credited with having. Lastly, there is the social responsibility component, which includes work ethics, respect of the state, workers and community, and a social licence to operate, including past practices and best practices that the proponent can effectively demonstrate to have set in place in its organisation.

Exploration and production contracts as state contractual concessions have a standard six-year exploration period and a 24-year production period. 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 3 of 2014, which complements Agreement 4 of 2012. Under this Agreement, production, reserves and economic solvency
capacities are different from those provided for conventional resources. Thus, depending on the reservoir that the proponent wants to develop, it will be regulated under Agreement 4 of 2012 (conventional reservoirs) or Agreement 3 of 2014 (unconventional reservoirs).

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 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 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.

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 programs. Recent assignments have taken more time than expected to be processed by the ANH and farmees and farmors should provide for

21 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.

22 Reference can be made to Decree 1073 of 2015.
this particular situation in their contractual arrangements. When assigning interests particular attention should also be placed 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. The applicable fiscal regime for the oil industry in Colombia consists of a combination of: (1) corporate income tax (with a 25 per cent tariff); (2) corporate income tax for inequality – CREE (with a 9 per cent tariff), (3) the recently created CREE surtax23 (with a 7 per cent tariff); and (4) royalties. In addition all goods and services are subject to a 16 per cent VAT. However, and as an incentive seeking the promotion of offshore oil and gas activities, on 23 December 2014 the Colombian Ministry of Trade, Industry and Tourism issued Decree 2682 of 2014 which allows the declaration of 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.

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.25 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

23 Tax created by Law 1739 of 23 December 2014 (Latest tax reform in Colombia).
24 Corporate income tax 25% 15%
CREE 9% 9%
Surtax/CREE 5% (2015) 0%
VAT 16% 0%
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

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.
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.

VIII CURRENT DEVELOPMENTS

It is important to analyse and consider the different implications and effects that the peace agreement will have in relation to the hydrocarbons sector.

A significant consequence of such agreement will be, without a doubt, the possibility to explore and eventually exploit new areas of the territory, which were previously out of reach for oil and gas companies and the state. Along with the greater exploitable area and the emerging ground potential, there will be an important reduction in the security costs for the oil and gas companies. Despite the above, conflict persists with the National Liberation Army (ELN), a radical armed group that is primarily responsible for attacks on oil infrastructure.

Likewise, 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 those effects, 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.

A favourable conclusion to the peace process may bring 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.
I  INTRODUCTION

The discovery of hydrocarbons within Cyprus's exclusive economic zone in December 2011 put the Republic of Cyprus on the world energy map and was embraced with wide enthusiasm. The findings have since been followed by plentiful developments that seek to transform the initial surprise into a well-founded aspiration of becoming a producer and exporter of hydrocarbons.

The oil and gas exploration area is of 51,000km² and is located in the south of Cyprus. This area has been separated into 13 exploration blocks.

To date, six licences and production sharing contracts (PSCs) have been applied for and obtained. The local authorities are considering other applications to award licences for the remaining blocks.

The recently formed state-owned Cyprus Hydrocarbons Company (KRETYK) has been given the mandate to manage Cyprus’s hydrocarbon resources and proceeds. The company also represents Cyprus in PSCs and deals with potential investors in relation to the construction of a liquefaction and export facility.

Further discussions between the Cypriot government and relevant entities concerning the infrastructure necessary for the transportation and liquefaction of gas are currently ongoing. These point to a period of at least five years until the essential facilities that can enable Cyprus to export on a desirable scale are established.
II LEGAL AND REGULATORY FRAMEWORK

The prospecting, exploration and exploitation of hydrocarbons in Cyprus are governed by several national legal instruments. Given that Cyprus is a Member State of the European Union, it additionally follows the Community acquis relating to oil and gas activities.

i Domestic oil and gas legislation

Relevant legislation includes the Law on Regulating the Electricity Market of 2003 No. 122(I)/2003, which establishes the Cyprus Energy Regulatory Authority (CERA).

In addition, the Laws on Regulating the Natural Gas Market of 2004–2012, No. 183(I)/2004 (30/04/04), No. 103(I)/2006 (21/07/2006), No. 219(I)/2012 (28/12/2012) and No. 199(I)/2007 (31/12/2007) are also part of Cypriot legislation. These laws were passed to bring the internal natural gas market in line with the EU Directive 2003/55/EC. The latter was, however, repealed and replaced with new Directive 2009/73/EC. Cyprus secured several deviations from this because it is regarded as an isolated market. The deviations will come to an end once Cyprus’ internal natural gas market ceases to be isolated.


The Hydrocarbon (Prospection, Exploration and Exploitation) Regulations of 2007 and 2009 (No. 51/2007 and No. 113/2009) are the regulations that determine the licences that can be obtained and provide guidance on procedural and application matters.

ii Regulation

Regulatory agencies

The Ministry of Commerce, Industry and Tourism – Energy Service (MCIT) is responsible for granting licences for prospection, exploration and exploitation of hydrocarbons as well as overseeing any activities that are directly related to these.

The Cyprus Energy Regulatory Authority (CERA), following the Natural Gas Law, No. 183/2004 (the Natural Gas Law) is to regulate the natural gas market.

The state-owned Natural Gas Company company (DEFA) has been given a wide mandate regarding the natural gas market in Cyprus. DEFA is responsible not only for the import and storage of natural gas in Cyprus but also for its distribution.

Regulator’s enforcement powers

CERA is responsible for handing out licences regarding the import, storage or gasification of natural gas. However, following the Law on the Regulation of the Natural Gas Market 2004 as amended by Law 199(I)/2007, DEFA, the sole entity responsible for the import and supply of natural gas in the market of Cyprus, was established. As a result of this monopoly, the role of CERA as a regulator responsible for issuing licences regarding the above activities is currently suspended.

CERA is, moreover, responsible for examining and regulating the possibility and implementation of an interconnection with another Member State.
The regulatory authority also has rather a significant influence over the market as it should maintain a sustainable balance between supply and demand of gas in the local market. To this end, misuse of a dominant position within the market will be prevented. Following an EU directive on the matter, assessing the supply and demand in the market includes ensuring smooth market conditions in cases of emergency and unforeseen crises.

CERA is also responsible for providing the technical design and operation minimum standards for the connection to the network. This covers other natural gas infrastructure.

It should be kept in mind, however, that all public authority decisions may be challenged by means of judicial review and thereby examined by the Supreme Court of Cyprus.

### Treaties

#### European Union legal framework

- **Directive 94/22/EC** of 30 May 1994 on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbon: identifies the procedure that should be followed for granting licences to ensure a transparent *modus operandi*. It additionally elaborates on time and geographical restrictions of authorisations.

- **Directive 2009/72/EC** of 13 July 2009 on common rules for the internal market in electricity seeks to secure an obstacle-free EU market for the sale of electricity and stipulates the policies that should be followed to ensure a free market where competition flourishes. In that regard, it calls for the furthering of cross-border interconnections that will ultimately guarantee a supply of all energy sources at competitive prices for the benefit of the European consumer. The Directive also tackles the above issue having in mind sustainable climate policy arguments.


- **Regulation (EC) No. 715/2009** of 13 July 2009 is based on the conditions for access to the natural gas transmission networks and rewrites the natural gas transmission and trades rules in order to remove any barriers to competition.

- **Regulation (EU) No. 994/2010** of 20 October 2010 on measures to safeguard security of gas supply acts as a vote of confidence to the Union’s ability to maintain a constant supply of gas within the internal gas market. The regulation puts a mechanism in place by which national and community authorities coordinate in order to deal with emergency situations. The ultimate goal is to prevent a supply disruption for protected customers, which includes households, social services and small enterprises.


#### International conventions

Cyprus is a party to several international conventions. These include:

* the International Arbitration in Commercial Matters Law 1987;


**Bilateral agreements**

Cyprus has initiated and concluded several bilateral agreements with neighbouring states. This includes the delimitation of the Exclusive Economic Zone of Cyprus with Egypt, which reflects the median-line principle as encompassed in the UNCLOS 1982 agreement. Cyprus and Egypt have capitalised on their cooperation with a framework agreement expanding on the development of a cross-median line concerning hydrocarbon resources. Other agreements have been signed on a political level with Israel, such as the ratification of the Delimitation Agreement by Law of the Exclusive Economic Zone and Israel, as well as with Lebanon. Cyprus and Egypt have also entered into a framework agreement regarding the development of cross-median line hydrocarbon resources.

**Double tax treaty network**

Cyprus has developed an extensive network of double tax agreements with almost 50 countries, ensuring that the same income is not taxed in more than one country. Under these treaties, entities registered in Cyprus will not only enjoy tax exemptions within Cyprus, but will additionally profit from analogous exemptions within other treaty countries.

### III LICENSING

The licensing regime in relation to hydrocarbon activities in Cyprus is governed by the Hydrocarbons (Prospecting, Exploration and Exploitation) Law 4(I) of 2007, as amended by Laws 126(I)/2013 and 29(I)/2014 (the Hydrocarbons Law) and supplemented by the Hydrocarbons (Prospecting, Exploration and Exploitation) Regulations of 2007 and 2009 (the Hydrocarbons Regulations). The above specify three types of licences that can be applied for and obtained. These relate to hydrocarbon prospecting, exploration and exploitation. Each licence pertains to a particular exploration block. The legal framework also provides the criteria that need to be fulfilled so that the applicant can be deemed eligible for each licence. Under Community Law 183(I)/2004, the transmission and distribution of gas without a licence is a criminal offence.

There are three types of licences that can be awarded:

- **a** Hydrocarbon prospecting licence: this licence grants its holder the right to attempt to locate hydrocarbons in a geographical area by any appropriate method other than drilling. This licence is subject to a statutory maximum term of one year.\(^2\)

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\(^2\) Article 8 of the Hydrocarbons Regulations.
Hydrocarbon exploration licence: the exploration licence can be obtained for up to three years\(^3\) and may be renewed for up to two terms, each term not exceeding two years, given that the licensee has satisfied its obligations in relation to a current exploration term. In every renewal of the term of the exploration period, the licensee must surrender at least 25 per cent of the initial surface of the licensed area. This licence covers gravity, 2D/3D seismic surveys and magnetic surveys, as well as one exploration drilling. If hydrocarbons are discovered, then the licensee is granted an exploitation licence.

Hydrocarbon exploitation licence: granted initially for up to 25 years and can potentially be renewed once for a further 10 years. It covers both exploration and exploitation if commercial hydrocarbons are discovered.

Licensing rounds

The invitation for the initial licensing round related to the exploration and exploitation licences for Block 12 was announced on 15 February 2007.

The first exploration licence for Block 12, which covers an area of 4,600 square kilometres, was granted to Noble Energy International in the first licensing round in October 2008. In October 2013, Noble Energy had placed the resource estimation in the specific gas field in the range of 3.6 to 6tcf.

A second bid round was concluded on 11 May 2012 for the 12 remaining offshore blocks. Interest was shown from 15 consortia/companies (a total of 29 different companies), which placed 33 applications for nine blocks.

The ENI-KOGAS consortium was given licences for Blocks 2, 3 and 9 in January 2013. The following month, Total E&P obtained licences for Blocks 10 and 11 but relinquished the licence for Block 10. ENI-KOGAS commenced exploration drilling in 2014, but a few months ago the said company asked the Republic of Cyprus for a two-year extension (i.e., until February 2018) to re-evaluate the geological model on which it based its initial estimates. The state, after having found the proper legal framework to satisfy the company’s request, decided to start negotiations on the two-year extension for hydrocarbon exploration in Cyprus’ Exclusive Economic Zone (EEZ).\(^4\)

Recently, the Republic of Cyprus announced the commencement of the third licensing round for offshore exploration Blocks 6, 8 and 10 in its exclusive economic zone.\(^5\) The efforts and perseverance of the President, Nicos Anastasiades, and of the Minister of Energy, Giorgos Lakkotrypis, to market the third licensing round were fruitful and led to a positive outcome.\(^6\) In fact, eight energy companies filed six bids for the three offshore blocks as follows: Block 6: ENI/Total, Block 8: ENI, Cairn/Delek and

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\(^3\) Article 9 of the Hydrocarbons Regulations.


\(^6\) Cyprus Mail, ‘Cyprus to take its pick for Block 10 in EEZ’, 7 August 2016, http://cyprus-mail.com/2016/08/07/cyprus-take-pick-block-10-eez/.
Block 10: ENI/Total, ExxonMobil/Qatar Petroleum (QP), Statoil. The importance of Block 10 stems from ENI’s discovery of the giant Zohr field off the coast of Egypt located very near Cyprus’ EEZ.

ii Type of instrument used

The specific conditions and requirements for the exploration and exploitation licences are incorporated in a contract agreement established between the government of Cyprus and the licensees. Such a contract may take the widely used form of a PSC or a concession agreement or both, or any other form of the arrangement of those used in the hydrocarbons industry. PSC was first used for the agreement between the government of Cyprus and Noble Energy International with respect to Block 12.

A model PSC can be found at the website of the Ministry of Energy, Commerce, Industry and Tourism of the Republic of Cyprus. The main clauses of the model PSC include the minimum exploration work programme; cost of oil and gas recovery; transfer – assignment; change of control; profit percentages; minimum annual training budget; performance guarantee and annual surface fees.

iii Licence limitations

The holder of a licence should ensure that all operations are carried out in a manner that shows respect to the environment and is in line with the current environmental legislation such as the International Convention on Civil Liability for Oil Pollution Damage. Good industry standards provide an attestation to this. Cyprus has followed Directive 2001/42/EC, transposing it into national law. It subsequently performed a strategic environmental assessment (SEA) to bring out and highlight any effects that the activities relating to hydrocarbons might have. Authorised parties are expected to comply with the SEA.

Furthermore it is obligatory, as stipulated by the model contract, for the licensee to ‘remove all equipment, installations, structures, plants, appliances and pipelines from the licensed area’. This should be coupled with all necessary site restoration activities in accordance with good international petroleum industry practices and take all necessary measures to prevent hazards to human life, the property of others or the environment’. This default position could be varied by the Minister of Energy, Commerce, Industry and Tourism (the Minister), who may also demand the issue of a guarantee for a determined amount or the setting up of a reserve for future abandonment and restoration expenses.

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8 Regulation 16 (1)(a)No. 51/2007 and No. 113/2009.
9 Ibid. Regulation 16(1)(b).
IV PRODUCTION RESTRICTIONS

i Restrictions on exports of oil and gas and on production entitlements
There are no restrictions on exports of oil and gas or on production entitlements. However, the annual work programme and development plan for each reservoir are accepted by the government and in this context the production needs to be approved.

ii Requirements for sales of production into the local markets
Through the provisions of the PSC model, the government may impose requirements for sales of production into the local markets. However, the Cypriot market is too small and the discoveries are already too large.

iii Law applicable to price setting
With regard to provisions applicable to price setting, the model PSC provides in general that the arm’s-length principle must be followed.

V ASSIGNMENTS OF INTERESTS
Any licences and rights stemming from them can be assigned or transferred. This, however, is subject to consent from the Council of Ministers of Cyprus. As Regulation 12(1) of the 2007 Regulations stipulates, for such a transfer, a written application must be made to the Minister. The Minister will in turn submit an opinion to the Council of Ministers, which will reach a decision.

The Council will consider whether the assignee or transferee possesses the adequate know-how, experience and resources to carry out the relevant activities. Possible national security issues will also be examined.

Moreover, the Council may decide to impose conditions on the original licence. The Ministry of Energy, Commerce, Industry and Tourism can provide guidance to the relevant application.

VI TAX
Despite it being the first time that Cyprus is deploying the natural resources found within its EEZ, various international energy companies have previously used Cyprus in order to benefit from the favourable and attractive taxation terms as well as the high standard of services that Cyprus has to offer.

At the moment there is no tax regime in Cyprus specifically for the oil and gas industry, although the tax authorities will provide such guidance in the future. For the time being, all contractors must abide by the taxation legislation currently in place in Cyprus.

This follows the EU VAT Directive as Cyprus is part of the EU Customs Union. The current principal VAT rate is 19 per cent. It should be noted that, as the PSC provides, corporate tax is held to be included within the profit share that belongs to the government. Subsequently, the contractor’s share is corporate tax-free.
It should be noted that profits arising from the activities of a permanent establishment (such as oil and gas exploration sites) in Cyprus will be exempt from any taxation in Cyprus.

Cyprus also has several double taxation treaties with other countries, as mentioned above.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact

Considering the potential impact that oil and gas operations might have on the environment, the legal framework stipulates an assessment of such operations. The relevant EU legislation is Directive 2001/42/EC, which was transposed into national law by the Assessments of the Effects on the Environment of Certain Plans and/or Programmes Law 140(I) of 2005.

The law requires an SEA to be executed so that the effect of hydrocarbon exploration and exploitation activities can be identified at an early stage. The SEA’s role is to identify, describe and evaluate the likely significant effects on the environment of implementing hydrocarbon exploration and exploitation activities as well as bind all the licensees to follow and comply with the results and recommendations of this assessment.

The environmental report that was prepared by Maritime Communication Services Inc., Aeoliki Ltd and CSA International Inc., can be located on the website of the Ministry of Energy, Commerce, Industry and Tourism. Contractors and subcontractors are equally required to comply with the findings of the SEA.

Hydrocarbon operations are further regulated by the general laws and regulations of Cyprus on environmental protection, health and safety. It is therefore obligatory for every authorised party to conduct the relevant activities in a safe and environmentally acceptable manner and to follow best international industry practices.

Contractors are also obliged to carry out a preliminary environmental impact assessment study prior to any exploration operations. This should be supplemented by a full environmental impact assessment study prior to any exploitation work. In other words, it should be ensured that hydrocarbon operations are conducted in an environmentally acceptable and safe manner, consistent with the environmental legislation and the good international industry practice.

ii Decommissioning

The removal, disposal or reuse of any structures used during the relevant processes is again guided by the terms of the model PSC. The contract requires the authorised party to obtain the approval of the Ministry of Commerce Industry and Tourism before proceeding with decommissioning.

For that to happen, contractors must put forward a decommissioning plan, together with any expected expenditure at least six years before the expected date of

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the decommissioning of a block or as soon as possible before the termination of any exploitation area. A consultation period between the parties, where amendments to the suggested plan are submitted, may follow.

A reserve fund should be established in order to safeguard the effective completion of any decommissioning activity. The fund should be deposited in a bank account and approved by the Ministry. In the event decommissioning costs prove to be greater than the amount reserved, any such costs are to be covered by the contractor. If costs are lower, on the other hand, any excess amount will be payable to the government.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
For oil and gas operations in Cyprus investors may choose to either establish a branch of a foreign operation or a local entity.

ii Capital, labour and content restrictions
The European internal market framework guides the movement of capital. Therefore, there are no limitations on the entry of foreign capital in Cyprus, other than those limitations stemming from international sanctions, terrorist financing or money laundering legislation.

Cyprus is party and signatory to the Schengen Agreement. There are thus no restrictions on the ability of companies to employ Cypriot or EU nationals. For workers that are not EU nationals, it is obligatory that they hold a residence permit or temporary visa that would enable them to work in Cyprus.

It is nevertheless stipulated in the model PSC that once operations begin the contractor shall ensure priority employment for Cypriot and EEA personnel and contribute to the training of those personnel in order to allow them access to any position of skilled worker, foreman, executive and manager.\footnote{Article 25.1 of the Model Exploration and Production Sharing Contract.}

iii Anti-corruption
Cyprus follows a European Council 2003 Framework Decision concerning corruption. The decision targets acts of both active and passive corruption and imposes criminal liability on those responsible.

There are also rules related to oil and gas activities passed by the European Parliament in 2011 that seek to shield consumers from abuses in wholesale oil and gas trading. The rules prescribe the independent monitoring of energy trading within the Union with the overall aim of combating anti-competitive practices.

This is further reinforced by the European legislation on Energy Market, Integrity and Transparency, which applies to all energy trading activity in the Community and criminalises market manipulation and insider information used. To achieve this, the
Agency for the Cooperation of Energy Regulations will supply Member States with details of breaches of the aforementioned laws.

IX CURRENT DEVELOPMENTS

In August 2015, Italy’s ENI discovered the ‘largest’ offshore natural gas field in the Mediterranean off the Egyptian coast and also very close to Cyprus’ Block 11 of the EEZ by using the drillship Saipem 10000. The Zohr will possibly be able to meet Egypt’s own natural gas demands for decades to come and hence will probably affect Cyprus positively. The Cypriot government had announced through its Minister of Energy, Yiorgos Lakkotrypis, that it is currently investigating whether the Zohr field extends into Cyprus’ EEZ. Should the Zohr field indeed extend into Cypriot waters, it is believed that the Cypriot and Egyptian governments will work closely towards jointly developing the reservoir. Furthermore, another impact that the Zohr field had on Cyprus is that Saipem’s pipelayer Castoro Sei is anchored at the Limassol port in Cyprus last July and will remain there for six months, utilising the port’s services. Therefore although the platform will be working for Zohr, this will have a positive impact on Cyprus’ economy such as on the local business, the port itself, the airports, hotels and restaurants. This indicates not only the right infrastructure, which Cyprus has, but also that this may encourage other companies to choose the Limassol port for their activities in the eastern Mediterranean.

Moreover, the cooperation that already exists between Cyprus and Israel in the field of energy may provide the option in the near future, and once the Cyprus problem is resolved, to pipe the gas through Turkey to southern Europe. This should be done quickly since the discovery in Egypt may be an indicator that there is more gas to be found in the Levant basin and in Cypriot waters. ENI-KOGAS is scheduled to continue drilling Block 9 of Cyprus’ EEZ and thus the possibilities of finding additional reserves remain high.

In addition, the government of Cyprus recently formed the National Geostrategic Council and the Energy Council, staffed by experts and academics who will provide guidance in relation to energy matters. In conclusion, ENI-KOGAS’s presence in Cyprus’ EEZ and particularly in Block 9, along with the recent discovery by Noble Energy in the Aphrodite field and the discovery of the Zohr field located near Cyprus, are sufficient reasons to be optimistic about the near future.

Another recent development in Cyprus is the agreement signed in late August 2016 between Cyprus and Egypt that involves the transfer of gas from Cyprus to Egypt though an undersea pipeline. The ‘new deal’ will support the sale of Cypriot natural gas to buyers in Egypt, provide certainty to investors and complement the relevant commercial discussions that are under way.
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 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 latest round finalised in 2016 resulted in the award of 16 new licences.

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.

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1 Michael Meyer is a partner and Anne Kirkegaard is a senior legal counsel at Gorrissen Federspiel. We are grateful to our colleagues, attorney Lars Fogh and junior attorney Sebastian D Thoning, for their contributions to this chapter on tax.

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 last round was finalised in April 2016. See further www.ens.dk.
The Danish state participates through the independent entity Nordsøfonden in all licences granted since 2005 whether in a licensing round or through the open-door procedure with a 20 per cent stake. In addition, Nordsøfonden participates with a 20 per cent stake in the Sole Concession.

Denmark has been a net exporter of energy since 1997 and is self-sufficient in oil and natural gas. For 2017 DEA anticipates an oil production of 8.4 million m³ and a production of natural gas (sales gas) of 3.9 billion Nm³. Denmark’s reserves of oil are as of 1 January 2016 estimated to 160 million m³ and of sales gas to 80 billion Nm³, both figures include contingent resources. DEA’s forecast for Denmark’s self-sufficiency in oil foresees that Denmark will be self-sufficient until 2018 and again between 2021–2026. If advancements in technology, exploration resources, etc., are included it is expected that Denmark will be close to self-sufficient until 2032 (except 2019–2020). Turning to natural gas, 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 2020–2021.

In 2010 Denmark granted two open-door licences for the exploration of shale gas in Northern Jutland and Northern Zealand, respectively. Both licences have by now been handed back due to the results of the exploration not being satisfactory.

As regards the activities in the North Sea Maersk Oil has announced that production from the fields Tyra and Tyra East will be discontinued in 2018 unless an financially acceptable solution is found in the course of 2016. Further, the operator of the Hejre field, DONG Energy, announced in March 2016 that the development of the field will be delayed due to termination of the EPC contract.

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

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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).

6 For details please refer to the publication ‘Resources and Forecasts’ of 29 August 2016 available at www.ens.dk.

7 Please refer to the publication ‘Resources and Forecasts’ of 29 August 2016 available at www.ens.dk.

8 Consolidated Act No. 960 of 13 September 2011 with subsequent amendments.

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 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.

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. All raw materials including hydrocarbons covered by the act belong to the Danish state. 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 (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. Since 1983 areas in the North Sea have been offered to interested companies in a total of seven licensing rounds. 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 DEA; see further Section V, *infra.*

In order to obtain a licence to initiate exploration of the subsoil as referred to in the DSA, a fee of 25,000 DKK is payable. 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. Additionally, a licensee is obliged

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12 Section 1(2) of the Danish Subsoil Act.

13 Section 2 of the Danish Subsoil Act.

14 Lars Chr. Lilleholt was appointed Minister for Energy, Utilities and Climate in June 2015.

15 See Section 1, *supra.*

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.

17 See the Statutory Order on Reimbursement of Expenses related to the Authorities’ Administration in connection with Hydrocarbon Activities, No. 1032 of 23 August 2007.
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).  

The Danish Continental Shelf Act

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

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.

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

The Danish Pipeline Act

The purpose of the DPA is concurrently with improving the recovery to reduce the environmental impact of transportation and landing of crude oil and condensate in the fields in the Danish part of the North Sea. Under the DPA, the owner, DONG Oil Pipe A/S, a subsidiary to Dong Energy 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 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, natural gas companies and customers with the right to choose their supplier may against payment be granted

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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.
19 Ratified by Denmark on 31 May 1963.
20 See Section 1 of the CSA.
21 See Section 4 of the CSA.
22 The pipelines are as part of the political agreement entered into regarding the IPO of DONG Energy A/S to be divested to the state owned Danish TSO, Energinet.dk. The listing took place on 9 June 2016.
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. 803 of 17 June 2016 on the payment for transport of crude oil and condensate.
access to upstream pipelines (e.g., pipelines operated or constructed as a part of an oil or gas production, and the technical facilities related hereto) provided that they meet the third-party access requirements.27

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

Regulation of safety and the protection of the environment for upstream oil and gas activities is primarily set out in the Offshore Safety Act,28 the Marine Protection Act,29 the Statutory Order on environmental impact assessment (Statutory Order on EIA)30 and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.31

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.32 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.33

The Marine Protection Act 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 Statutory Order on EIA 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 has been carried out.34 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

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27 See the Statutory Order No. 1090 of 6 December 2000 on access to the upstream pipelines.
28 Consolidated Act No. 831 of 1 July 2015 with subsequent amendments.
29 Consolidated Act No. 1616 of 10 December 2015 on the Protection of the Marine Environment with subsequent amendments.
30 Statutory Order No. 1419 of 3 December 2015 on environmental impact assessments, etc.
32 Section 1 of the Offshore Safety Act.
33 Section 5 of the Offshore Safety Act.
34 Section 3 and Section 4 of the Statutory Order on EIA, see note 36.
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.
See Section VI, *infra*, for further information on the taxation schemes for upstream oil and gas activities.

**Regulatory agencies**

DEA is an agency under the Ministry of Energy, Utilities and Climate and is i.a. responsible for matters relating to energy supply and consumption.\(^{38}\) DEA is responsible for the entire chain of tasks concerning energy production and supply, transportation and consumption, including energy efficiency and savings. Additionally, 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 DEA’s powers, it rests with the Minister.\(^{39}\)

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

Disputes regarding access to the upstream gas pipelines and fees and prices connected hereto, are referred to DERA 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

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\(^{38}\) See Statutory Order No. 436 of 11 May 2012 on the DEA’s duties and powers.

\(^{39}\) See Statutory Order No. 436 of 11 May 2012 on the DEA’s duties and powers, Section 11.

\(^{40}\) See Statutory Order No. 163 of 26 February 2000, Section 1.

\(^{41}\) See Statutory Order No. 163 of 26 February 2000, Section 3, on DERA’s duties and powers, see also DERA’s Order of business, Section 2 and Section 9.

\(^{42}\) See Section 37 (a) of the Danish Subsoil Act.


\(^{44}\) Statutory Order No. 117 of 7 March 1973.

\(^{45}\) Consolidated Act No. 1255 of 16 November 2015 with subsequent amendments.

\(^{46}\) Act No. 533 of 24 May 2005 with subsequent amendments.
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 Subsoil Act\(^{47}\) based on one of the licensing methods outlined in Section II.i, *supra*. DEA has finalised seven rounds\(^{48}\) of applications for licenses to explore for hydrocarbons in the North Sea. The seventh licensing round covers the unlicensed area west of 6° 15’ eastern longitude, including Central Graben, where most of the Danish finds have been made.

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 DEA within the framework of the Subsoil Act and supporting regulation as set out in Section II.i, *supra*.

The main terms of the model licence for the seventh 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, organisation of the business and evaluation 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 DEA and DEA’s rights of participation as observer as well as confidentiality obligations;\(^{53}\)
- **e** obligations regarding connection to the existing upstream pipelines;\(^{54}\)
- **f** liability issues (strict liability), insurance obligations, obligation to provide security;\(^{55}\)
- **g** 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;\(^{56}\)

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\(^{47}\) 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, *supra*.

\(^{50}\) The model licence terms Section 3 with Annex 1.

\(^{51}\) The model licence Sections 4 and 17 with Annex 2.

\(^{52}\) Ibid. Section 18.

\(^{53}\) Ibid. Sections 19–23.

\(^{54}\) Ibid. Section 27.

\(^{55}\) Ibid. Sections 30–32.

\(^{56}\) Ibid. Sections 34–37.
the full immunity granted by the licensee regarding any claim that may be raised against the Danish state following the licensee’s activities;\textsuperscript{57} and
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.\textsuperscript{58}

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 seventh licensing round regulate, \textit{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 DEA.

\section*{IV PRODUCTION RESTRICTIONS}

A licence to establish and operate pipeline systems for use regarding activities covered by the DSA may be restricted by conditions issued by the Minister. Accordingly, a licence may be granted on terms restricting dimensions, transport capacity, ownership, etc.\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.

\subsection*{I 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

\begin{itemize}
\item\textsuperscript{57} Ibid. Section 38.
\item\textsuperscript{58} Ibid. Section 40.
\item\textsuperscript{59} DSA, Section 17(2).
\item\textsuperscript{60} DSA section 17a and Act No. 354 of 24 April 2012 on oil minimum stocks with subsequent amendments.
\item\textsuperscript{61} Statutory Order No. 1090 of 6 December 2000.
\item\textsuperscript{62} Ibid.
\item\textsuperscript{63} See Section 5 of the Statutory Order on access to upstream pipeline.
\end{itemize}
between applicants and the final agreement, including the prices, must be reported to DERA. DERA ensures that the owners of the pipelines do not abuse their (in reality) monopoly rights.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 Subsoil Act that a licence may neither directly nor indirectly be transferred to a third party unless DEA approves of the transfer including any terms and conditions attached to such transfer.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 DEA. This also applies to transfers of shares or parts in a licence if there are several licensees to the same licence.66 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. DEA may in order to approve a transfer, whether in whole or in part impose conditions on the parties to the transfer.67 The Danish state has no preferential right of purchase to licences issued under the DSA.

Even though a transfer has been approved by DEA the transferor of a licence for exploration or production of hydrocarbons68 or a licence to establish or operate upstream pipelines69 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.70 Accordingly, no licensee can escape the financial liability for decommissioning costs.

It follows from the Subsoil Act that any expenses incurred by DEA in the handling of a licence, including the approval of a transfer, shall be borne by the licensee.71 Licences issued pursuant to the Subsoil Act enjoy immunity from legal prosecution.72

64 Ibid.
65 See DSA section 29(1).
66 A provision to this effect is also included in the model licence for the seventh round, Section 33.
67 See DSA section 29(2).
68 Cf. DSA Section 5.
69 Cf. DSA Section 17.
70 See DSA Section 29a.
71 Statutory Order No. 1032 of 23 August 2007 and No. 920 of 14 July 2010 on the reimbursement of costs.
72 Cf. DSA Section 29(3).
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 Act73 and the Hydrocarbon Tax Assessment and Collection Act.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.75

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

ii Tax rates and income types

The two-string Danish hydrocarbon tax system combines corporate income tax at the rate of 25 per cent77 (Chapter 2 income) and a special hydrocarbon tax at a rate of 52 per cent (Chapter 3A income) for the income year of 2016. The overall effective tax rate for Chapters 2 and 3A income is 64 per cent.

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

Income related to, inter alia, hydrocarbon feasibility studies, services to hydrocarbon companies, the construction of pipelines, services and transportation of hydrocarbons is not covered by Chapters 2 or 3A. This income is, as other ordinary corporate income, subject to the ordinary corporate income tax rate at 22 per cent for the income year 2016.

73 Consolidated Act No. 862 of 19 June 2014.
74 Consolidated Act No. 966 of 20 September 2011.
75 See www.skat.dk.
76 I.e., for separate income under Part 2 and for hydrocarbon income pursuant to Part 3A of the Hydrocarbon Tax Act.
77 The ordinary corporate income tax of 22 per cent added 3 per cent for hydrocarbon activities for 2016.
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.

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,78 the DSA, the Statutory Order on EIA etc.,79 the Statutory Order on alerts regarding pollution of the sea from oil and gas facilities, pipelines etc.,80 and the Statutory Order on Safety Zones and Zones for the Observance of Order and the Prevention of Danger.81

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

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

78 Consolidated Act No. 1616 of 10 December 2015 with subsequent amendments.
79 Statutory Order No. 1419 of 3 December 2015.
80 Statutory Order No. 909 of 10 July 2015.
82 See Sections 28(a), 28(b) and 28(c) of the Danish Subsoil Act and Section 6 of the Statutory Order on EIA.
83 See Sections 3–8 of the Statutory Order on EIA 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, etc.).
Details of regulatory agencies with responsibility for environmental regulation

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

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

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

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

Summary of legal requirements with respect to decommissioning

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

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

第八节 外国投资考虑

在外国投资方面，没有特别的要求或限制。但是，在获得探矿权和开采权的公司必须在法国的税务机关进行注册，并提供必要的信息。否则，公司可以，例如，建立一个丹麦分公司或在丹麦登记一个商业地址。

84 See the Danish Subsoil Act, Section 8.
85 See the Danish Subsoil Act, Section 24(a).
86 See the Danish Subsoil Act, Section 12(a).
87 Ibid.
IX CURRENT DEVELOPMENTS

As mentioned above, the award of licences following applications in the seventh licensing round took place in the spring of 2016. In total, 16 licences were awarded to Danish and foreign companies or groups of companies.

The operator of the Tyra fields, Maersk Oil, announced in April 2016 that the production from both Tyra East and Tyra West will cease on 1 October 2018 unless ‘an economically viable solution for continued operations’88 is found during 2016. Tyra is the largest gas field in the Danish part of the North Sea and one of the natural gas pipelines from the North Sea installations to Nybro starts at Tyra. Turning to the production of oil DONG Energy A/S did on 29 March 2016 announce that they had terminated the EPC contract for the platform to be installed at the Hejre Field. The future development of the Hejre Field, if any, has not yet been announced.

Following the IPO of DONG Energy A/S in June 2016 the state-owned TSO, Energinet.dk, based on the political agreement to float DONG Energy A/S, shall purchase the natural gas infrastructure as well as the oil pipelines currently owned by DONG Energy A/S.

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88 Quote from Maersk Oil’s press release of 4 April 2016.
Chapter 8

FRANCE

Yves Lepage, 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.

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.

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 and the present government has clearly confirmed that it does not intend to propose a change to the existing legislation.

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

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1 Yves Lepage is a partner and Geoffroy Berthon is an associate at Orrick, Herrington & Sutcliffe.
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 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 his 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 without the consent of the landowner entitles the prospector to collect the proceeds of its exploration works, 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 and 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.

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</th>
<th>Recent production royalty rate</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 cubic metres, is as follows:

<table>
<thead>
<tr>
<th>Production</th>
<th>Old production royalty rate</th>
<th>Recent production royalty rate</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. 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(s) 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 is still ongoing. At this stage, the main features of this reform include the following (subject to any changes during the finalisation of the reform):

a the prefect could no longer grant works authorisations, leaving the Minister for Mines as the sole authority responsible for making decisions relating to mines;
b all mining decisions having an environmental impact could first require an environmental assessment involving the public;
c the legal regime applicable to facilities classified for the protection of environment – pursuant to which the state has extra rights in this area – could apply to mining works and installations;
d the mining procedure could be simplified by shortening existing deadlines;
e the liability of the operator of the mine for post-mining damages could be clarified. In the event that the French-registered operator disappears, the party for which the works have been completed could be held liable, regardless of its nationality or ties with the French operator; and
f the revised tax regime under which the mining title holder and local authorities benefiting from the royalty could contract for part of the royalty.

This ongoing reform process does 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 2013-346 QPC, 11 October 2013).
Chapter 9

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 upstream 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 17th 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.

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.
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 establishes the Ghana National Petroleum Corporation (GNPC) as the national oil company to champion activities in the upstream oil and gas sectors. In addition, the now repealed Petroleum (Exploration and Production) Act 1984 (PNDCL 84) was passed to regulate petroleum activities in the upstream sector. Further, the Petroleum Income Tax Law 1987 (PNDCL 188) was passed to establish the taxation regime for the upstream oil and gas sector. Further to the discovery of oil in commercial quantities in 2009, the Petroleum Commission Act 2011 (Act 821) was passed to set up the Petroleum Commission as a regulator and coordinate activities in the upstream petroleum industry. The government recently passed the Petroleum (Exploration and Production) Act 2016 (Act 919), which repealed the 1984 Act, to regulate petroleum activities in the upstream sector. In addition, there is the Petroleum Revenue Management Act 2011 (Act 815) as amended by Petroleum Revenue Management (Amendment) Act 2015 (Act 893), which provides the framework for management of petroleum revenues.

iii Industry and foreign investment overview

The established state oil and gas corporation, the GNPC and the passage of the above legislation laid the foundation for the take-off of the industry. Efforts by the GNPC led to an increase in activities in the sector to find oil. These 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 GNPC adopted a model petroleum agreement based on international best practice to attract IOCs. These attracted a number of IOCs to invest in the upstream oil and gas sector including Kosmos Energy Ghana Limited, Hess Ghana Limited, Tullow Ghana Limited, Norsk Hydro Oil, Heliconia Energy Resources and Anadarko. These investments 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 (the Jubilee Partners) 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 a consortium of IOCs in the following proportions: Tullow Oil (49.95 per cent), Kosmos Energy (18 per cent), Anadarko (15 per cent), GNPC (10 per cent) and Sabre Oil & 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 & Gas (1.85 per cent), and EO Group (3.5 per cent). The

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7 Ibid.
field is operated by Tullow Oil as the lead exploration company. The field has proven reserves of approximately 3 billion barrels and is currently producing approximately 110,000 barrels of oil per day.


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 square kilometres, was approved by the government of Ghana. Production has commenced and the first oil was delivered in August 2016. The Jubilee Partners have also completed appraisal activities for discoveries at Wawa, Mahogany Deep, Teak, Akasa, Paradise, Hickory North, Almond, Beech, Cob, Pecan and PN-1. 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-1, Gye-Nyame-1 and Sankofa East fields in the OCTP with other partners including Vitol Upstream Ghana Limited and GNPC. From 2013 to date, over 10 exploration licences have been issued to other players in the industry including Heritage Oil, AGM Petroleum, Britannia-U, Sahara Energy Fields and Camac Energy in the Western Basin.

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. It is estimated that Ghana has approximately 22.65 billion cubic metres of proved reserves of natural gas in its oil fields. 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 EPCC agreement with SINOPEC in 2012 for the development of the Western Corridor Gas Infrastructure Development Project. The project, was commissioned in September 2015 and consists of an offshore pipeline, an onshore pipeline, a gas processing plant and an NGLs export system at Atuabo in the Western Region of Ghana. At full capacity, the facility is expected to produce 107 million

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8 Ghana Gazette, No. 5, 2014.
11 Ibid.
standard cubic feet of lean gas, 500 tonnes of LPG, 80 tonnes of pentane and 45 tonnes of condensates daily. There are current discussions to connect the gas infrastructure to the West Africa Gas Pipeline to maximise the use of the gas.

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 reinforced by the Petroleum (Exploration and Production) 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 regulations 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).

Due 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) and the Petroleum (Local Content and Local Participation) Regulations 2013 (L.I. 2204). There is also the Petroleum Revenue Management Act 2011 (Act 815) that governs the use of petroleum revenue accruing to the state from petroleum exploration.

i Domestic oil and gas legislation

The main legislation relating to the upstream oil and gas sector are the following.

The Ghana National Petroleum Corporation Act 1983 (PNDCL 64)
The first major activity to set the stage for regulatory reform to govern the upstream sector was the establishment of the GNPC under the PNDCL 64. The GNPC is established as the national oil corporation charged with the responsibility to explore, develop, produce and dispose of petroleum products.

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 oversight 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. Under the Petroleum Revenue Management Act, a specific percentage of the net cash flow from the carried and participating interests is ceded to the GNPC for use in its operations.

The newly enacted Petroleum (Exploration and Production) Act 2016 (Act 919)
The newly enacted Petroleum (Exploration and Production) 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 of Energy 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 of Energy 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 decide not to enter into a petroleum agreement after the 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 Petroleum Exploration and Production) 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 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 due 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 dollars 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;
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;

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

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

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

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;

the establishment of a local content fund;

pollution damage, liability of the polluter;

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

payment of royalties; and

payment of a bonus to Ghana.

The Act also prescribed specific terms that must be provided in the petroleum agreements.
These include:

the right of GNPC to hold an initial participating carried interest of at least 15 per
cent for exploration and development;

the GNPC has the option to acquire an additional participating interest as determined
in the petroleum agreement within a specified period of time;

the petroleum agreement must be for a term not exceeding 25 years subject to ability
of the Minister to extend;

change of ownership of contracting party subject to consent of the Minister or
Commission;

the GNPC has the pre-emption to acquire interest of contractors.

The general requirements for petroleum activities under the Act include:

the standard of operations in conducting petroleum activities;

supervision and inspection;

data and information obtained by a licensee, contractor or sub-contractor as a result
of petroleum activities are property of Ghana;

maintaining records of data and information in Ghana;

provision of information upon request by the Minister;

the use of Ghanaian goods and services; and

the local content plan.

**The Petroleum Commission Act 2011 (Act 821)**

As part of the reform after the discovery in commercial quantities of oil and gas in Deepwater
Tano/Cape Three Points Basin, 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’. The specific functions of the Petroleum Commission are stated below. 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 Act focuses on ensuring maximum participation of indigenous Ghanaians, increase local capacity and also safeguard the interest of foreign participants in the oil and gas sector.

The Act applies to contractors, subcontractors, service providers, licensees and allied entities in the petroleum sector. The Act provides 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 of Energy. Service providers in the sector must have a minimum of 10 per cent Ghanaian ownership. Other provisions include the requirement for 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.

**The Petroleum Revenue Management Act 2011 (Act 815)**

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 Stabilization Fund and the Ghana Heritage Fund – and indicates how revenues accruing from petroleum operations to the state are to be disbursed and utilised.

All the funds created under the Act are deemed as 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.

**Regulation**

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

The 1992 Constitution vests all petroleum resources in the government of Ghana. The government expresses its ownership and regulatory rights over oil and gas activities through the Ministry of Petroleum. The mandate of the Ministry of Petroleum 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 commencement of 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:

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

iii) Treaties
Ghana signed onto 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.

Further, Ghana has signed bilateral investment treaties (BITs) with over 25 countries; however, only seven 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 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 Petroleum 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 of Petroleum. Although
the new Petroleum (Exploration and Production) Act provides for a competitive bidding regime for the award of petroleum rights, this option is yet to be implemented by the Ministry. To date, 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 of Petroleum. If an applicant is qualified, the Minister will constitute a petroleum agreement negotiation team comprising senior officials from the Ministry of Petroleum, 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 Petroleum has developed the Model Petroleum Agreement (MPA), which is the basis of negotiations with prospective contractors. The terms include the following:

\begin{itemize}
  \item \textit{a} incorporation of the contractor in Ghana;
  \item \textit{b} the area of activity;
  \item \textit{c} the exploration period of up to seven years;
  \item \textit{d} state benefits including carried and paid interest, additional oil entitlement, income tax, rental of government property and surface rent, etc.;
  \item \textit{e} 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;
  \item \textit{f} restrictions on assignment (subject to consent of the Minister);
  \item \textit{g} conditions for relinquishment;
  \item \textit{h} obligations of the contractor including time for notification of discoveries, commencement of appraisal programmes and submission of development plans, etc.;
  \item \textit{i} 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;
  \item \textit{j} content of development plans including a plan for utilisation of associated gases;
  \item \textit{k} measurement and pricing of crude oil;
  \item \textit{l} conditions for use and flaring of natural gas;
  \item \textit{m} conditions for discovery and production of natural gas;
  \item \textit{n} environmental safety provisions including the regulator’s right to inspection and emergency reporting;
  \item \textit{o} title to equipment;
  \item \textit{p} relinquishment and decommissioning;
  \item \textit{q} local content (procurement of goods and services, contribution to training); and
  \item \textit{r} dispute resolution (mandatory 30-day period for consultation and negotiation, arbitration under the Arbitration Institute of the Stockholm Chamber of Commerce, Stockholm, Sweden).
\end{itemize}
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:

a. relinquishment and surrender of the entire contract area;
b. failure to give notification of a discovery after the maximum exploratory period;
c. contractor’s failure to commence operations within the time limit for commencement;
d. submission of false information to the Petroleum Commission;
e. assignment of rights without consent of the Minister;
f. insolvency or bankruptcy of the contractor; and

g. 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 new Petroleum (Exploration and Production) Act on the various payments to be made and interests granted to the GNPC have been met, there are no restrictions on the distribution of production.

Under the new Petroleum (Exploration and Production) Act, the 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, the contractor may be required by the Minister of Petroleum 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 new Petroleum (Exploration and Production) 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 of Energy. This restriction applies to both contractors and subcontractors. The new Petroleum (Exploration and Production) 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 on 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.
Under the new Petroleum (Exploration and Production) Act, 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) as amended by the Income Tax Act, 2015 (Act 896). Under this Act, 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 allowed 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.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The new Petroleum (Exploration and Production) Act and the Model Petroleum Agreement 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 any activity that adversely affects 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 guideline relating to oil and gas activities is the EPA Guidelines for Environmental
Assessment and Management in the Offshore Oil and Gas Development (2010). These guidelines require preliminary environmental assessments for small to medium-impact scale undertakings and EIAs for field development and production activities.

The new Petroleum (Exploration and Production) 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. Under the new Petroleum Exploration and Production Act, contractors are required to create a decommissioning fund as prescribed in the development plans to finance the decommissioning process during the life of the oil field.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The new Petroleum (Exploration and Production) Act requires a contractor in a petroleum agreement 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 with 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, LI 2204 regulates local content in the upstream sector. Significant provisions include the following requirements:

- minimum of 5 per cent indigenous participation (other than GNPC) in petroleum agreements;
- 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;
- minimum targets for areas such as front-end engineering design (FEED), fabrication and construction, materials and procurement, well drilling services, marine operations and logistics services and transportation, supply and disposal services;
- submission of a local content plan showing how priority will be given to local goods and services and use of local professionals and a training plan;
- an employment and training sub-plan;
- a research and development sub-plan;
- a technology transfer sub-plan;
- a legal services sub-plan; and
- a financial services sub-plan.

LI 2204 places an obligation on contractors to hire more Ghanaians over time and develop plans for attaining almost 100 per cent indigenous employment within 10 years of petroleum operations.
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. Even though the new Petroleum (Exploration and Production) Act provides for a competitive bidding process, all petroleum agreements entered into to date have been through direct negotiations. Also, the variation of terms in the various agreements have raised concerns about the need for such variation.

The introduction of an anti-corruption warranty clause in four recent petroleum agreements entered into by the government 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 The TEN Project

The Tweneboa-Enyenra-Ntomme (TEN) Project is the next significant oil find in Ghana. The first wildcat well was drilled in 2009 approximately 20km from the Jubilee Fields. This was followed by further successful appraisal and exploration wells and the discovery of the TEN field. Approval for development of the field was granted in May 2013 and production of first oil was in August 2016. The field is currently estimated to have approximately 300 million barrels of oil and 365 billion cubic feet of gas. The estimated oil production from the field is expected to average approximately 80,000 barrels a day. The production is being carried out by the second floating production, storage and offloading (FPSO) vessel named FPSO Professor John Evans Atta Mills, after the late president who oversaw first oil from Ghana’s Jubilee Field in 2010. The FPSO, which arrived in Ghanaian waters in March 2016, has the capacity to process up to 80,000 barrels of oil per day from the TEN fields.

ii World Bank guarantee for the Sankofa Gas Project

In July 2015, the board of the World Bank approved a pledge of US$700 million in guarantees for the Sankofa Gas Project. The pledge comprises of an International Development Association payment guarantee of US$500 million that supports timely payments for gas purchases by GNPC and an International Bank for Reconstruction and Development Enclave Loan guarantee of US$200 million that enables the project to secure financing from its private sponsors. Together, the guarantees are expected to mobilise US$7.9 billion in new private investment for offshore natural gas, representing the biggest foreign direct investment in Ghana’s history.
iii Recent licensing rounds

The latest round of petroleum agreements ratified by Parliament include the following:

a Deepwater Cape Three Points West Block (944km²) between the government of Ghana, GNPC, A-Z Petroleum Products Ghana Limited and Eco Atlantic Oil and Gas Limited;

b Shallow Water Cape Three Points Block between the government of Ghana, the GNPC and Sahara Energy Fields Ghana limited;

c South-West Cape Three Points Block between the government of Ghana, the GNPC, GNPC Exploration and Production Company Limited, A-Z Petroleum Products Ghana and Eco Atlantic Oil and Gas Ghana;

d Offshore Cape Three Points South Block between the government, Ghana National Petroleum Corporation, GNPC Exploration and Production Company Limited, UB Resources limited, Royalgate Ghana limited and Houston Drilling Management; and


iv Dispute resolution

The Petroleum Commission has positioned itself as the mandatory mediator of all disputes in the oil and gas sector prior to arbitration or other dispute resolution mechanisms. Recently, the Commission addressed an issue involving Mitsui Ocean Development & Engineering Co Ltd (MODEC) (the manufacturers of the FPSO Kwame Nkrumah) and Seaweld Engineering Limited, a local subcontractor, over discrepancies in the working conditions of local rig workers and expatriate staff.

v Ghana–Ivory Coast maritime border dispute

On 26 February 2010, after the Dzata-1 discovery by Vanco and Lukoil, a claim was made by Ivory Coast in respect of the territorial area of the discovery. Ivory Coast submitted a petition to the UN to complete the demarcation of the maritime border. After years of failed bilateral negotiations, Ghana, in September 2014, commenced arbitration proceedings under Annex VII of the UN Convention on the Law of the Sea before the International Tribunal on the Law of the Sea (ITLOS). In April 2015, the ITLOS gave an interim ruling that Ghana should continue developing offshore projects in the disputed area, but imposed a ban on new drilling. The final ruling on the merits of the dispute is expected in 2017.

vi Pending legislation

The Petroleum Commission is currently working on new Regulations on fiscal metering, health and safety, drilling and well engineering, and data management.
Chapter 10

GREECE

Yannis Kourniotis and Paris Tzoumas

I INTRODUCTION

Oil is the dominant energy source in Greece, accounting for approximately 45 per cent of the country’s total primary energy supply in 2012.\(^2\) However, despite ‘data showing characteristic lines with their corresponding geological cross sections’\(^3\) in certain areas of Greece, almost all of the crude oil used in Greece is imported. Given the above, a competitive energy policy focusing on upstream oil operations in Greek territory could make a significant contribution to the country’s economic recovery.

In this regard, in recent years we have witnessed the Greek state make remarkable efforts to reinitiate the process of domestic hydrocarbons exploration and production in Greece, many years after the last exploration round was tendered in 1997.\(^4\) The main fruit of these efforts was the execution (in May 2014) of three lease agreements, entered into between the Greek state and three consortia (the first consortia) regarding hydrocarbon exploration and production in the areas of West Patraikos Gulf, Ioannina and Katakolo.

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1 Yannis Kourniotis is a partner and Paris Tzoumas is an associate at M&P Bernitsas Law Offices.
3 See www.balkanalysis.com/greece/2014/07/11/in-london-greece-promotes-new-offshore-hydrocarbons-investment-potential [last accessed on 23 September 2016; 15.30 CET] with regard to the presentation of a survey’s results on Greek offshore blocks, as conducted by Norway’s Petroleum Geo-Services (PGS).
4 We are referring to the first international tender regarding six areas out of which four areas in western Greece were finally granted. The exploration was not successful due to the fact that the wells did not reach the agreed depths.
Greece

More specifically, the first consortia comprised major oil and gas players in the national and international market (i.e., Energean Oil & Gas and Petra Petroleum Inc for the Ioannina area, Energean Oil & Gas and Trajan Oil for the Katakolo area and Hellenic Petroleum, Edison International S.p.A. and Petroceltic Resources plc for the West Patraikos Gulf). The First Lease Agreements, following their ratification by the Greek parliament, supersede the generally applicable oil legislation, due to their specific legal nature. Additionally, in April 2014 the company Enel Trade SpA submitted to the Ministry of the Environment and Energy an expression of interest for the exploration and exploitation of hydrocarbons within three onshore areas of western Greece – Arta-Preveza, Aitoloakarnania and NW Peloponnese, making use of the relevant provisions of Law 2289/1995 (namely under the process described in Section III.ii.(b) infra). By virtue of Ministerial Decision 9167 (OGG 1491/B/06.06.2014) the Minister accepted the aforementioned expression of interest and invited other possible interested parties to participate in this tendering procedure. This procedure has since then progressed smoothly and preferred bidders have been selected by the Greek state. The negotiations between the Greek state and the preferred bidders are currently at their final stage and such agreements are expected to be executed between the parties by the end of 2016 (the ‘Second Lease Agreements’).

Please note that upstream gas operations in Greece are almost non-existent while on the other hand there is increasing interest in the upstream oil operations, so we will be commenting exclusively on the latter.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic hydrocarbons legislation

Law 2289/1995 (Prospecting, Exploration and Production of Hydrocarbons and other provisions), which has transposed Directive 94/22/EC on the conditions for granting and using authorisations for the prospection, exploration and production of hydrocarbons, constitutes the main applicable legislation governing the prospecting, exploration and production of hydrocarbons in Greece.

Law 2289/1995 was further amended by Law 4001/2011. As a general remark, we note that in the amended Law 2289/1995 the Greek state tried to incorporate new practices that have been successfully followed for more than a decade by other European oil-producing states, these being the ‘non-exclusive seismic surveys’ as well as the ‘open door concession rights system’, aiming to create a more appealing investment climate and to attract serious investments in the oil sector.

Law 2289/1995 distinguishes between two main stages related to upstream oil operations: the exploration stage and the production stage. The exploration stage shall have a maximum duration of seven years for the onshore areas and eight years for the offshore areas, starting in both cases from the date of execution of the relevant agreement with the Greek state, while the production stage shall have a maximum duration of 25 years from


the date on which the contractor or lessee notifies the Greek state that it has tracked down a commercially exploitable crude oil deposit. Both stages may be extended under certain conditions provided by the same law.

Under the Greek legal framework, as opposed to other jurisdictions, the decision as to whether a discovered deposit of hydrocarbons is commercially exploitable rests with the contractor who undertakes to notify the Greek state regarding the commercial exploitability of the deposit and the anticipated amount of its recoverable reserves.7

With regard to dispute resolution, according to the applicable legislation, all disputes among the parties, related either to the performance of the terms of the agreement or to any non-contractual liability, shall be settled through arbitration, according to Law 2735/1999 for international commercial arbitration or any other internationally recognised arbitration system, such as the International Chamber of Commerce (ICC), the London Court of International Arbitration or the Arbitration Institute of the Stockholm Chamber of Commerce, excluding ordinary proceedings of the Greek courts or other court jurisdictions. Such decision shall be rendered through three arbitrators, two of whom shall be appointed by the parties with the umpire being appointed jointly by the two arbitrators. The place of arbitration proceedings shall be Athens and the language applied shall be Greek. All claims in conjunction with Law 2289/1995 shall be governed by Greek law.

In the First Lease Agreements, however, the same issue is resolved quite differently but in a manner reflecting the market standards. More specifically, it is provided that a number of serious disputes between the first consortia and the Greek state shall be referred for determination to a sole expert from the Energy Institute of London, the American Petroleum Institute or the French Institute of Petroleum. This sole expert decision can be subsequently referred to arbitration by way of appeal on a point of law, but not on a point of fact. The other disputes, which are not subject to a sole expert determination, shall be finally settled by arbitration.

ii Regulation

By virtue of Presidential Decree (PD) 14/2012 (OGG 21/A/2012), a new state-owned company under the name Hellenic Hydrocarbon Resources Management SA (HHRM) was established, based on the provisions of Articles 145-153 of Law 4001/2011. All of the rights and obligations relating to the prospecting, exploration and production of hydrocarbons are vested in the HHRM, which acts on behalf of the Greek state and manages these rights and obligations. The scope of the company includes, inter alia, the management on behalf of the Greek state of the exclusive rights for the exploration and production of hydrocarbons, the management and monitoring of the existing state agreements, the conduct of all relevant exploration or production tenders, the evaluation of offers received, the preparation of the relevant contract agreements and the constant supervision of their appropriate execution, as well as the preparation of all environmental protection, labour, safety and security regulations that will govern the operation of any oil and gas company in Greece.

Despite the formal establishment of the HHRM, it has not been fully operational yet due to lack of specialised personnel and thus its involvement in the First Lease Agreements tender and negotiation process was very limited. Given that HHRM is currently in the

7 Please refer to Article 5, paragraph 8 of Law 2289/1995.
Greece is a signatory of the Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention), which was ratified by Law 4220/1961.

Greece is an EU Member State and a signatory of a number of international treaties and conventions of relevance to the oil and gas industry, most notably the Energy Charter Treaty (ECT), and the International Convention for the Prevention of Pollution from Ships (MARPOL).

Further to the above, Greece has concluded bilateral investment protection treaties with 46 countries, and has also signed double taxation prevention treaties with 57 countries.

### III LICENSING

According to Law 2289/1995, the rights to prospecting, exploration and production of hydrocarbons that exist in onshore areas, sub-lake and submarine areas where the Greek state has sovereignty or sovereign rights in accordance with provisions of the United Nations Convention on the Law of the Sea belong exclusively to the Greek state. The term 'prospecting for hydrocarbons' refers to the attempt to locate hydrocarbons in a specific area by any appropriate method other than drilling, while the term 'exploration of hydrocarbons' refers to the exploration for the discovery of hydrocarbon deposits by any appropriate method, including drilling. The term 'hydrocarbon production' includes the extraction of hydrocarbons, any treatment necessary to make them marketable as well as their storage and transportation to the loading installations for further disposal. Under this law, the management of the above-mentioned rights is exercised by the HHRM, on behalf of the Greek state. The specific role, powers and responsibilities of the HHRM are discussed in Section II.ii, supra.

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8 For a list of Greece's bilateral investment protection treaties (BITs), see http://investmentpolicyhub.unctad.org/IIA/CountryBits/81#iiaInnerMenu [last accessed on 23 September 2016; 16.22 CET].

9 For a list of Greece's double taxation treaties, see www.gsis.gr/gsis/info/gsis_site/ddos/b.html [last accessed on 23 September 2016; 16.25 CET].


11 Despite the fact that Law 2289/1995 provides explicitly for the HHRM as being the entity responsible to exercise such competencies and despite also the fact that HHRM has now been formally established by virtue of Presidential Decree (PD) 14/2012 (OGG 21/A/2012), it still seems to lack appropriate organisation and staff in order to handle its new competencies. For this reason, at present, the competencies vested upon it are still exercised through the Ministry of the Environment and Energy. Therefore a reference to HHRM herein may still, in practice, denote the Minister of the Environment and Energy.

12 See Article 2, paragraph 1 of Law 2289/1995, as amended and in force.
i  Granting of the right of prospecting for hydrocarbons

The right of prospecting for hydrocarbons is granted by a decision issued by the HHRM. More specifically, the HHRM issues an invitation for submission of applications for prospecting for hydrocarbons that is approved by the Minister of the Environment and Energy (the Minister), which is published in the government gazette and the Official Journal of the European Union. The invitation, which may also be issued following the submission of application by an interested party, includes the area that shall be subject to prospecting, the terms and obligations of the licensee, the criteria for the selection, the amount of the fee payable and the amount of the good performance letter of guarantee to be issued, the deadline for the granting of the licence, and any other relevant information. Within the time limit set out in the invitation, the HHRM shall grant the licence for prospecting, which is approved by the Minister and shall be valid for up to 18 months.13

ii  Granting of the rights of exploration and production of hydrocarbons

The exploration and production rights are granted:

a following an invitation to tender, approved by the Minister, published in the government gazette and the Official European Union Journal;

b following the application by an interested party for an area not included in the above invitation to tender. If the HHRM accepts this application, it issues an invitation to tender that needs to be approved by the Minister, and published in the government gazette and the Official European Union Journal; or

c through an open invitation (open door) for the submission of interest if the area under discussion is available on a permanent basis or has been subjected previously to a tender that was not completed with the execution of a lease or production sharing agreement or has been abandoned by the contractor, if the latter has withdrawn from or terminated the respective agreement. The Minister, by virtue of an announcement published in the government gazette and the Official European Union Journal, gives notice of the said areas along with the minimum basic terms of the concession, as well as any specific information related thereto. The interested parties are eligible to submit offers related to these areas until the last day of the first and second semester of each calendar year. Within 30 days from the end of the relevant semester, the Minister announces that the area for which offers have been submitted, as above, is excluded from the areas available for concession. The offers are evaluated following negotiations with the interested parties and the one most financially advantageous to the Greek state is selected.

Irrespective of the tender process, the invitation to tender should specify the geographical areas, the type of agreement to be concluded, the terms and criteria of participation such as the minimum financial capability and the technical expertise of the interested parties, any prior experience in exploration and production of hydrocarbons, and any record of successful implementation of such projects by means of a concession contract. Furthermore, in the invitation to tender, the requirements for participation and the evaluation criteria shall be set out in detail and such criteria and requirements shall include the royalty offered by the interested parties in case of a lease agreement and the participation interest in the

13 See Article 2, paragraph 5 and 6 of Law 2289/1995, as amended and in force.
Greece

hydrocarbons offered to the Greek state in case of a production sharing agreement, as well as the signature bonus and the production bonus. The invitation to tender may also provide for a payment by the successful tenderer (the contractor) to the Greek state of an amount of compensation per annum that may be determined by reference to the surface area used during the exploration and production stage (the so-called ‘surface fees’).

With regard to the applicable tender procedure, the European Commission officially exempted\textsuperscript{14} the exploration for oil and gas in Greece from the application of Directive 2004/17/EC\textsuperscript{15} (coordinating the procurement procedures of entities operating in the water, energy, transport and postal services sectors) recently. An activity provided under this Directive can be excluded from the scope of its application given that the said activity is directly exposed to competition in the Member State in which it is performed, and access to such activity’s relevant market is not restricted. The European Commission found that the above conditions are met and thus exempted contracts awarded by contracting authorities pertaining to oil and natural gas exploration in Greece from the application of Directive 2004/17/EC. It is noted, however, that this Commission Implementing Decision could be revised should any significant factual or legal changes occur in the respective Greek market.

The Greek state’s exploration and production rights may be granted through:

\begin{itemize}
\item[a] the conclusion of a lease agreement; or
\item[b] the conclusion of a production sharing agreement.
\end{itemize}

Both types of agreements are signed by the Greek state or the HHRM, as the case may be, and the contractor and must be approved by the Minister. Without approval, the agreements are null and void and produce no legal effect. Both types of agreements may provide for the state’s participation in a joint venture with the contractor, both in the exploration and the production stage. In the case of the First Lease Agreements, further to the Minister’s approval, the agreements were ratified by the Greek parliament, owing to the deviations they contain from Law 2289/1995. The same is expected to occur in respect of the Second Lease Agreements.

The type of agreement that should be concluded in respect of a certain contract area (i.e., whether the preferred type will be a lease agreement or a production sharing agreement) is each time determined by a ministerial decision issued by the Minister of Energy and the Environment.\textsuperscript{16} Please note that, by virtue of Ministerial Decision No. D1/A/30260/30.12.2011 (OGG 376/B/2012) the type of lease agreement has been selected as the preferred type in respect of the contract areas comprising the First Lease Agreements, while it was by virtue of the Ministerial Decision No. D1/A/12552/23.07.2014 (OGG 2093/B/2014) that the type of lease agreement was once again selected as the preferred type in respect of the Second Lease Agreements.

PD 127/1996 sets the basic terms and conditions regarding the lease of the right of exploration and production of hydrocarbons. While Law 2289/1995 sets forth the general terms and conditions regarding the production sharing agreement, it also provides for the

\begin{itemize}
\item[15] See Official Journal L 134, 30 April 2004. Please note that this process was initiated by Hellenic Petroleum SA, a company that was part of the first consortia.
\item[16] See Article 2, paragraphs 10 and 14 of Law 2289/1995, as amended and in force.
\end{itemize}
issuance of a more detailed PD on this issue. Until now, this PD has not been issued. In any case, under Law 2289/1995, the two types of agreements have many similarities, the main difference being the ownership of the hydrocarbons. In the lease agreement, the contractor acquires ownership of the extracted hydrocarbons at the time it acquires possession of them. If the state decides that the lease is to be paid in hydrocarbons, together with the contractor, it is co-owner of the quantity of the extracted hydrocarbons equalling the amount of the lease. Nevertheless, in the production sharing agreement, the state acquires ownership of the hydrocarbons as of their extraction. In this case, the contractor acquires ownership solely of those hydrocarbons that constitute its share, as well as of those used to cover its expenses.

IV PRODUCTION RESTRICTIONS

According to Law 2289/1995, the contractor is free to market and sell the extracted hydrocarbons either locally or abroad by exporting them, unless it is otherwise agreed in the agreement concluded between the contractor and the state. Neither any of the First Lease Agreements included such a restrictive provision, nor are the Second Lease Agreements expected to include such a restrictive provision. However, according to the applicable legislation, in the event of war, the threat of war or any other state of emergency in Greece, the contractor is obliged to sell to the state, upon the request of the latter, all or part of the hydrocarbons produced that originally belonged to the contractor. The First Lease Agreements include this state of emergency provision and a similar term is also expected to be included in the Second Lease Agreements.

In case of emergency, as well as in cases where both parties have agreed that part or all of the extracted hydrocarbons will be sold to the Greek state, the selling price is preset by Law 2289/1995.

V ASSIGNMENTS OF INTERESTS

According to Law 2289/1995, the contractor may transfer, in whole or in part, its contractual rights and obligations to an independent third party, solely upon the written consent of the state and following the approval of the Minister. The state may refuse to grant its consent for national security reasons arising from the nationality of the third party, as well as for reasons regarding the financial and technical capability of this third party. The state may exercise a pre-emption right in case of substitution of the contractor or transfer of its shares. Consent is also required whenever any affiliate enterprise that controls the contractor is to be transferred.

The contractor may transfer, in whole or in part, upon written consent of the state and approval by the Minister, its contractual rights and obligations to an affiliate enterprise, provided that the contractor continues to be, in relation to the state, fully and jointly liable with the transferee affiliate enterprise, for the performance of all obligations under the agreement. The state may refuse to grant its consent for national security reasons as described above. Where the contractor is a joint venture, each member is entitled to transfer its rights and obligations under the agreement to any other member, upon written consent of the state and approval by the Minister. The state may exercise a pre-emption right in case of substitution of the contractor or transfer of its shares.

Given that there is no commercial precedent on this matter, the timing regarding the granting of the written consent is quite uncertain. However, due to the major importance of the issue, we believe that it will be addressed as a high priority.
VI TAX

According to Law 2289/1995, the contractor shall be subject to a special income tax, at a rate of 20 per cent and to a regional tax, at a rate of 5 per cent, without any additional ordinary or extraordinary contribution, duty or other encumbrance of any kind, in favour of the state or any other third party. Income tax will be imposed separately on the contractor’s income deriving from each of the agreements concluded by it. The tax shall be imposed on the net taxable income earned by the contractor’s operations under each agreement, and accounts for any and all income tax obligations of the contractor and its shareholders, with respect to profits deriving from the operation under the agreement.

If the contractor is a joint venture, the income tax will be calculated and imposed separately for each participating member. However, the members of the joint venture will remain fully liable for the income tax due from the other members of the joint venture.

The income of the contractor under the agreement, the income acquired abroad by the foreign employees of the contractor for services relating to the operations under the agreement as well as the income that is acquired by the foreign employees of the contractors and subcontractors employed by the contractor, even if the latter are residents of Greece, are exempt from any direct or indirect, general or special, regular or extraordinary, tax, duty, stamp duty, royalty, ordinary or extraordinary contribution and deduction and are generally exempted from any financial charge, regular or extraordinary, in favour of the state or any third party, except for value added tax.

The contracts for loans or credit provided to the contractor by banks or credit institutions or any foreign legal entities of any nature for the performance of hydrocarbon exploration and exploitation operations, under the agreement, and their repayment shall be exempted objectively from any general or special, ordinary or extraordinary tax, duty, stamp duty, royalty, ordinary or extraordinary contribution and deduction and are generally exempted from any financial charge in favour of the state or any third party, except for value added tax. The interest on the above loans or credits is, however, subject to income tax.17

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact

According to Law 2289/1995, by virtue of ministerial decisions, regulations shall be enacted regarding the prospecting, exploration and production of hydrocarbons aiming, inter alia, to prevent the pollution or contamination of the environment and the protection of flora and fauna within the exploitation areas. However, such regulations have not yet been issued. Therefore, as the general environmental legislation applies, the contractors must carry out all petroleum operations in full compliance with the approved strategic environmental assessment and the terms of environment resulting from the relevant environmental impact assessment that the contractor needs to submit to the competent governmental authority, for preventing any environmental damage that might be caused by the petroleum operations. In addition, the contractors must comply with the legislation on solid and hazardous waste and must minimise any environmental impact of the petroleum operations within the contract area, and in adjoining or neighbouring areas.

17 See Article 9 of Law 2289/1995, as amended and in force.
Before carrying out any drilling activities, the contractor shall fully meet the requirements of the applicable legislation for safety, contingency (i.e., oil spill, fire, accident, emissions) and major hazard-management plans.

The contractor shall also take all necessary measures to minimise any environmental pollution or damage to water, soil or the atmosphere that may occur in connection with hydrocarbon activities. Where the state considers that any works or installations erected or any activities carried out may endanger persons or property of another person or pollute or cause harm to the environment, fauna, flora or marine organisms, the state will require the contractor to take corrective measures within a reasonable period to repair any damage to the environment. The state may also suspend a contractor’s contractual rights until the latter has done so.

To comply with the provisions hereof, the Minister may require a deposit guarantee from the contractor, the amount of which is to be determined by the Minister, upon the recommendation of the HHRM, or, alternatively, the contractor must be covered by an insurance contract with an international firm against all risks, including environmental risks.

With regard specifically to offshore areas where oil and gas operations take place, Directive 2013/30/EU on the safety of offshore oil and gas operations has very recently been transposed into Greek law, by virtue of Law 4409/2016 (OGG 136/A/2016). Further to the Directive’s relevant provisions, Law 4409/2016 puts in place a set of rules in order to prevent major accidents in the context of offshore petroleum operations; and to ensure an adequate response system in cases of emergency.

More specifically, as regards the prevention of major accidents related to offshore petroleum operations, Article 3 paragraph 4 of Law 4409/2016 provides that the operators must conduct their operations on the basis of a risk management system in a way that the residual risks of major accidents to individuals, the environment or the offshore installations per se, remain at an acceptable level. The operators will remain fully liable for any acts or omissions of the contractors they may engage. Article 4 of Law 4409/2016 provides that the competent authority will only grant licenses to any applicants after first taking into account the proven technical and financial capability of the latter. A list of criteria shall be taken under consideration by the competent licensing authority in that respect, which include, inter alia, the risks, the hazards and any other relevant information relating to the area under concern, the applicant's financial capability to adequately cover liabilities potentially arising from its offshore petroleum operations, as well as any available information relating to the safety and environmental performance of the applicant. After the granting of any licence to a licensee,

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19 According to Article 2 paragraph 1(a) of the law, the term ‘major accident’ means in relation to an installation or connected infrastructure: (1) an incident involving an explosion, fire, loss of well control or release of oil, gas or dangerous substances, involving, or with a significant potential to cause, fatalities or serious personal injury; (2) an incident leading to serious damage to the installation or connected infrastructure involving, or with a significant potential to cause, fatalities or serious personal injury; (3) any other incident leading to fatalities or serious injury to five or more persons who are on the offshore installation where the source of danger occurs or who are engaged in an offshore petroleum operation in connection with the installation or connected infrastructure; or (4) any major environmental incident resulting from the above sources.
the latter remains obliged to maintain adequate financial capability in order to comply with any potential liabilities that may occur in the context of its offshore petroleum operations. Moreover, Article 5 of the same law provides for a mandatory stage of a substantial public consultation process before any exploration wells are drilled for those areas for which a licence had not been granted on or before 18 July 2013, while Article 13 provides that the owner of oil production facilities in an offshore area shall prepare a report on major hazards for a non-production installation submitting the same to the competent authority. The operations relating to production and non-production installations, as well as the well operations and any combined operations cannot commence or continue until such report on major hazards is approved by the competent authority. Besides, Article 7 of the law provides that the licensee will remain financially liable for the prevention and remediation of environmental damage caused by offshore petroleum operations carried out by it (or the operator to the extent this is a different entity). Pursuant to Articles 8 and 9, the competent authority referred to above shall be established as an independent authority. In particular, according to Article 8 paragraph 4 of the law, a presidential decree shall be issued by the Minister to formally establish such competent authority. Such presidential decree has not been issued yet and the law stipulates that, to the extent the installations existing in Greece with regard to offshore petroleum operations are less than six in total, the duties of the competent authority shall be exercised provisionally by the HHRM.

The operator, or the owner, of the offshore facilities, shall submit to the competent authority a full set of documents, prior to carrying out any offshore petroleum operations. Such documents comprise the corporate major accident prevention policy, the safety and environmental management system applicable to the installation, a design notification (in the case of a planned production installation), a description of the independent verification scheme, the report on major hazards and any necessary amendments thereof, an internal emergency response plan, a notification of any well operation, a notification of any combined operations, any relocation notification and any other relevant document that may be requested by the competent authority. The competent authority may, *inter alia*, prohibit the operation or commencement of operations on any installation or connected infrastructure where the measures proposed, in the context of the above documentation, regarding prevention of damage are considered as insufficient to fulfil the requirements of the law. It is also empowered to require improvements where the protective purpose of the law is not adequately fulfilled or it maintains reasonable concerns about environmental safety.

Article 22 establishes a ‘whistleblowing’ process, in that the competent authority shall establish mechanisms for confidential reporting of safety and environmental concerns relating to offshore petroleum operations and such established mechanisms and their confidential nature (anonymity) shall be communicated to the employees and contractors of the operators or owners by the operators or owners themselves.

Coming to the establishment of an adequate response and preparedness system, Article 28 of the law provides that the competent authority will make sure that the internal emergency response plan, as above described, is put into action without delay and is consistent with the external emergency response plans. External emergency response plans are emergency action plans to prevent at a local or national level the repercussions of a major

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20 The report on major hazards must be reviewed at least every five years (Article 12 paragraph 7 of Law 4409/2016).
accident and which are prepared, in respect of each offshore petroleum installation and any potentially affected areas, by the competent authority in cooperation with relevant operators, owners and licensees, as well as any other public authorities that share such competence. They are based on a national emergency response plan that shall be prepared by the competent authority in cooperation with the General Secretariat of Civil Protection covering all offshore petroleum installations operating in Greece and any potentially affected areas. No national emergency response plan has been prepared yet for Greece.

Last but not least, Article 27 of the law establishes a special framework for the cooperation between the Greek competent authority with the respective competent authorities of the other member states through the network of the EU Offshore Oil and Gas Authorities Group (EUOAG), while article 31 contains provisions regulating potentially practical transboundary effects of the application of the law in different member states.

**ii Decommissioning**

Upon the expiry of any production stage of an exploitation area, the contractor must:

- appropriately plug all producing wells and known water zones;
- remove all installations; and
- restore the environment.

The operations of the contractor under (b) and (c) will be supervised by a committee of specialists. A special reserve may be raised in order to cover the expenses required for decommissioning. The above obligations apply *mutatis mutandis* where the contractor is declared forfeited or where the contractor renounces its production rights.

**VIII FOREIGN INVESTMENT CONSIDERATIONS**

According to Law 2289/1995, the contractors must be natural persons or legal entities, acting solely or, if there are more than two, as a joint venture, having European Union nationality or being registered in the European Union or having a third-country nationality, under the reciprocity principle. Following the conclusion of the agreement with the state, the contractors may not be placed under the direct or indirect control of a foreign state that is not a Member State of the European Union, or under the direct or indirect control of a citizen of such state without the prior approval of the Greek Council of Ministers.

**i Establishment**

According to Law 2289/1995, if the contractor is constituted of more than two members, it needs to be formed as a joint venture. Under Greek law, joint ventures can either be a consortium, without legal personality, which is addressed as an undisclosed partnership or a civil company, which if engaged in commercial activity has to be registered with the Company’s Register (GEMI).

However, in the First Lease Agreements, as ratified by law, it is expressly stated that for the purposes of the First Lease Agreements, any reference to the term ‘joint venture’ in the Law 2289/1995 means the contractual cooperation of the companies or members of the consortium under a joint operating agreement, without creating or implying or having the intention to create any, *de jure or de facto* partnership or entity with a separate legal personality. Furthermore, it is expressly stated that each member of the consortium shall be jointly and severally liable in respect of the obligations arising under the lease agreement.
against the lessor (the state) and each member of the consortium shall hold an undivided interest in all of the rights under the lease agreement. Similar provisions are expected to be inserted in the Second Lease Agreements.

It is also worthy of note that under Greek law, an overseas company can also trade in Greece through a branch office. To establish a branch office in Greece, the approval of the local competent authority, as well as the registration of the branch with GEMI is required.

ii Capital, labour and content restrictions

Capital restrictions

Greece is a Member State of the EU and the eurozone and therefore the EU internal market rules regarding foreign exchange and the movement of capital apply in principle in its territory. However, in a state of emergency for the liquidity of the Greek banking system, capital controls have been imposed in Greece since 28 June 2015 and are still in force as contained in the Legislative Act of 18 July 2015 (OGG 84/A/2015) on the establishment of limitations on cash withdrawals and transfer of capital, as the latter has been amended up to date by virtue of various ministerial decisions and other legislative acts. On that basis, payments outside Greece may, as a general rule, be either prohibited or be made subject to a prior approval by a special capital controls committee, though some specific categories of transactions may not require prior approvals. In parallel however, Article 2 paragraph 4 of the PD 127/1996 has always provided that ‘the contractor has the right to transfer abroad its income acquired […] within the context of performance of its works […]’. Given that this provision has never been repealed and is a special provision of the hydrocarbons legislative framework it may be interpreted to constitute an exemption from the above-mentioned general capital controls restrictions. In any case, whether an intended outbound payment is subject to the capital controls restrictions is something that needs to be examined in advance by the relevant interested entity on a case by case basis and in close cooperation with the competent Greek authorities.

Finally, it is noted that the above mentioned capital restrictions are of a non-permanent nature. However, there is no clear indication as to how long these will remain in full force and effect.

Labour restrictions

As Greece is a Member State of the EU, the fundamental right of free movement of workers within EU borders is fully respected.

With regard to third-country citizens, according to Law 2289/1995, the contractor, as well as the subcontractors thereof, shall be entitled to employ in Greece foreign personnel or nationals of third countries for operations requiring special expertise. The competent authorities, following a proposal by the Minister of the Environment and Energy who examines the relevant applications submitted by the contractor or its subcontractors, shall issue to the personnel referred to above and to the members of their family, visas and residence and work permits in Greece, unless there are reasons against this pertaining to national security and public policy.22

21 The said Legislative Act has been ratified by virtue of Article 4 of Greek Law 4350/2015 and has thus acquired the power of law.

22 See Article 6, paragraph 8 and 9 of Law 2289/1995, as amended and in force.
iii **Anti-corruption**

Acts of active and passive bribery are illegal in Greece. As regards the acts of active bribery, Greek laws will apply to any individual making or offering any kind of benefit to Greek government officials, MPs, local (municipality or prefecture) council officials, public servants, the judiciary, foreign public officials and private sector employees residing in Greece or abroad (provided in the latter case that the act is committed by a Greek citizen and is also a criminal offence in that country). Legal entities will face civil and administrative sanctions (but not criminal sanctions as legal entities in Greece are not criminally liable) for any acts of bribery committed to their benefit. As regards passive bribery, Greek laws will apply to any Greek government official, MP, local (municipality or prefecture) council official, public servant, the judiciary, foreign public official or private sector employee, who asks or receives any kind of benefit or promise thereof.

Further to the above, please note that many companies established in Greece have already decided to introduce anti-corruption codes of conduct in order to educate their personnel.

**IX CURRENT DEVELOPMENTS**

Following the success of the First Lease Agreements and the forthcoming execution of the Second Lease Agreements, interest in the upstream oil operations in Greece seems to have been reinvigorated after a long period of stagnation. In this context, the Greek government has been engaged in an ambitious programme to also tender out several other offshore blocks for the exploration and production of hydrocarbons. The final deadline for the submission of tender applications was 14 July 2015 and the preferred bidders are expected to be selected by the Ministry of the Environment and Energy in the near future.
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.

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1 Michael Meyer is a partner and Anne Kirkegaard is a senior legal counsel at Gorrissen Federspiel. The authors wish to thank their colleagues attorney Lars Fogh and junior attorney Sebastian D Thoning, for their contributions to this chapter on tax.

2 Act No. 473 of 12 June 2009 on Greenland’s Self-Government.
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 and South West Greenland. Currently (2016), a licensing round covering the Disko and Nuussuaq areas is open for applications.

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.

Certain non-exclusive prospecting licences have also been issued. Licensees include TGS-NOPEC Geophysical Company, Statoil Greenland, GX Technology, Capricorn Greenland Exploration, ConocoPhilips, Norwegian University of Science and Technology, EMGS, Shell Greenland, DONG E&P Grønland, GDF Suez and Cambridge Arctic Shelf Programme.

As is evident, various international oil companies from Europe and North America have been granted oil and gas licences in Greenland. The recent dramatic fluctuations and decrease in oil prices may result in fewer deposits of hydrocarbons being 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 2014.4

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.

3 Inatsisartut Act No. 7 of 7 December 2009 with subsequent amendments.
4 A bill setting out certain changes to the Act will be introduced at the autumn 2016 session of Inatsisartut.
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

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:

5 For more information, see www.govmin.gl.
Greenland

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 licenses 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 subjected 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 2014 open-door procedures are 50,000 Danish kroner and 200,000 kroner for the granting of an exploration or 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 (issue 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 (issue 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 2016 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. Accordingly, the total effective tax rate is 31.8 per cent.

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. 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

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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\textsuperscript{7} (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\textsuperscript{8}, 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.

In addition to the oil and gas licences already in issue, as described in Section I, \textit{supra}, it is expected that further new licences will be issued over the coming years. The government has to date announced that it will conduct licensing rounds in 2017 (Baffin Bay) and 2018 (Davis Strait).

Several licences applied for in 2016 for areas in West Greenland or East Greenland are currently under assessment by the MLSA. 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 how many further licences will be issued, and whether any exploration activities will lead to licensees initiating exploitation where oil or gas production will become a reality in Greenland.

\textsuperscript{7} Inatsisartut Act No. 25 of 18 December 2012.

\textsuperscript{8} Inatsisartut Act No. 5 of 19 May 2010.
I INTRODUCTION

Having only recently become open to foreign investment in its upstream sector after years of sanctions, the Republic of Iraq is emerging as an important area of focus for international oil companies. While currently beset by a number of challenges, including low oil prices and IS 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.

II LEGAL AND REGULATORY FRAMEWORK

i Constitutional framework

The basic legal framework for the oil and gas sector in the Republic of Iraq is set forth in the Constitution of Iraq, which was approved by the Iraqi people by referendum on 15 October 2005 and entered into force in 2006. The relevant provisions of the Constitution provide as follows:

Article 111:

Oil and gas are owned by all the people of Iraq in all the regions and governorates.

1 Christopher B Strong is a partner at Vinson & Elkins LLP.
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.
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.

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.

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.

- A clear right for licence holders to transfer profits outside of Iraq (after payment of relevant taxes).
- A requirement that petroleum revenues be ‘distributed fairly among the people’, as regulated by a separate law.
- 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 ‘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:

- 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.
- 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.
- The refining company is entitled to establish and operate stations for the sale of gasoline and other oil products.
- 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).
- 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.
The refining company is entitled to all of the benefits stipulated in the Investment Law (No. 13 of 2006), including:

- a 10-year tax holiday from commencement of operations;
- a three-year exemption on import duties for imported assets, with a subsequent exemption for spare parts and parts required for expansions;
- the right to repatriate capital and salaries;
- the right to open and maintain offshore bank accounts;
- the right to employ non-Iraqis if the refining company is unable to employ suitably qualified Iraqi nationals (subject to a requirement in the Refinery Law that at least 75 per cent of employees must be Iraqi nationals); and
- the right to provide for international arbitration in its commercial contracts.

In addition to the incentives noted above, the Refinery Law imposes a number of requirements on companies seeking to invest in the refining sector, including the following:

- all refineries must employ ‘highly advanced technology’, and heavy oil products cannot exceed 20 per cent of total production;
- the refining company must construct, operate and maintain a pipeline connection from the refinery site to the Iraqi crude oil pipeline network;
- the refining company is not entitled to trade in crude oil or in products produced by state-owned refineries;
- the refining company is responsible for ensuring the supply of electrical power and all other utilities necessary for the operation of the refinery;
- 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;
- the refining company must observe all laws and regulations relating to the environment and industrial safety; and
- as mentioned above, at least 75 per cent of the employees of the refining company must be Iraqi nationals.

iv Treaty network

Iraq is not a party to the 1958 Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention), but it is a signatory to the 1983 Riyadh Convention for Judicial Cooperation (the Riyadh Convention). Under the terms of the Riyadh Convention, judgments rendered in one contracting state may be enforced in the courts of another contracting state, subject to the exclusions set forth in the Riyadh Convention.

III LICENSING

i Types of instruments and key licence terms

The principal contracts used for the licensing of petroleum interests in Federal Iraq are the technical service contract (TSC), which is used for the redevelopment of producing
fields, and the development and production service contract (DPSC), which is used for the development of discovered but undeveloped fields.

Under both TSCs and DPSCs, the contractor is remunerated on the basis of cost recovery and a per-barrel remuneration fee. This represents a key difference between the contracts used in Federal Iraq and the production sharing contracts found in other parts of the world, where the contractor is remunerated on the basis of cost recovery plus a share of ‘profit petroleum’ (generally, the portion of petroleum production remaining after the contractor has received its allocation of cost recovery petroleum). The size of the remuneration fee varies between blocks, with producing blocks generally receiving a lower fee and exploration blocks generally receiving a higher fee. The remuneration fee also varies in accordance with an ‘R-factor’, under which a ratio of the contractor’s cash receipts to its expenditures is periodically calculated, and as the ratio increases the remuneration fee decreases. Importantly, the remuneration fee does not take into account oil prices, which means that the contractor receives no upside from higher oil prices and it not exposed to downside as a result of lower prices. Its return is based solely on its ability to meet the production targets specified under the contract.

Under both TSCs and DPSCs, the contractor only becomes eligible to recover its costs and receive its remuneration fee once it has met the eligibility criteria specified in the agreement; provided that certain costs defined as ‘supplementary costs’ (which generally include signature bonuses, costs for remediation of pre-existing environmental conditions and de-mining, and costs for certain facilities as specified in the TSC or DPSC) can be recovered more quickly. For TSCs, the eligibility criteria are satisfied either upon achieving a specified level of production over a period of 30 days or the lapse of a specified period (generally three years) after the approval of a rehabilitation plan, while for the DPSCs the eligibility criteria are similar, except that instead of achieving a specified level 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.
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/day refinery have repeatedly been delayed but Iraq’s Oil Minister, Mr Allaibi, has recently called for the administration delays offering the project to be reduced so that it could be restored.

IV PRODUCTION RESTRICTIONS

Iraq is a member of OPEC and has indicated that it will begin complying with OPEC production quotas at some point in the near future, although the date upon which it will begin complying and the production quota to which it would be subject have yet to be determined. Iraq’s quota at the time of the first Gulf War (when it was officially excluded from OPEC’s quota system) was 3.8 million barrels. The effect on the TSCs and DPSCs of any future agreement by the Iraqi government to comply with OPEC production quotas is unclear.

V ASSIGNMENTS OF INTERESTS

Under the terms of the TSCs and DPSCs, companies are not entitled to assign any of their rights or obligations to any person other than a 100 per cent affiliate without the prior written consent of their Iraqi counterparty. For these purposes, the TSCs also generally provide that a direct or indirect transfer of shares or other ownership interests constitutes an assignment.

Given that the TSCs and DPSCs have all been awarded relatively recently, there has not been much history to date of the government’s approach to transfers of interests. Anecdotal evidence relating to the few examples where interests under TSCs or DPSCs have been transferred indicate a willingness on the part of the government to allow transfers, particularly where the proposed transferee is technically and financially qualified, but the government nevertheless retains broad discretion in choosing whether to consent to transfers of interests and in setting the conditions for its consent.

VI TAX

Foreign oil companies operating in Iraq are taxed in accordance with the Law of Income Tax on Foreign Oil Companies Working in Iraq (Law No. 19 of 2010) (the Oil Tax Law) and its accompanying regulations (Regulation No. 5 of 2011) (the Tax Regulations).

The Oil Tax Law provides that income earned in Iraq from contracts signed with foreign oil companies and their subsidiaries, branches and subcontractors working in Iraq in the field of oil and gas extraction, production and related industries will be taxed
at a rate of 35 per cent. The Tax Regulations go on to clarify that the types of contracts on which the 35 per cent tax rate is applicable include:

- contracts for the exploration, development and production of exploration blocks and oil and gas fields (i.e., TSCs);
- seismic survey contracts;
- contracts for the drilling of wells;
- contracts for the reclamation of wells;
- contracts for well services including casing, cementing, stimulation, electrical logging and completion;
- contracts for surface installations of oil and gas extraction and production operations;
- contracts for water injection facilities;
- contracts for flow pipes;
- contracts for gas treatment facilities;
- contracts for cathodic protection;
- contracts for engineering surveys and quality control;
- contracts for the drilling of water wells; and
- other activities relating to the extraction process through the point of export.

Pursuant to the Tax Regulations, the Ministry of Oil is required to deduct 35 per cent from the revenues due to foreign oil companies, and the foreign oil companies are required to deduct 7 per cent of amounts payable to their subcontractors. All amounts so deducted are to be held on deposit by the State Commission of Taxes and reconciled during the final taxation process.

For matters not specified in the Oil Tax Law or the Tax Regulations, the Law on Income Taxation (No. 113 of 1982) will apply.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

Iraq’s principal legislation in relation to environmental issues is the Law on Protection and Improvement of the Environment (Law No. 27 of 2009) (the Environmental Law). The Environmental Law sets forth broad requirements relating to the prevention of pollution and the management of hazardous waste. It also imposes the following specific requirements on entities involved in the exploration and extraction of petroleum and natural gas:

- to take necessary measures to limit the dangers and risks resulting from petroleum operations;
- to take necessary measures to protect earth, air, water and underground reservoirs from pollution and destruction;
- to take necessary precautions to dispose of produced salt water through safe environmental methods;
- to prevent spills of oil and refrain from injecting oil into subsurface areas that are used for human and agricultural purposes; and
to provide the Environmental Ministry with information about the causes of any fires, explosions, breakdowns, accidents and leakage of crude oil and gas from wells and pipelines.

In addition to the requirements of the Environmental Law, the TSCs and DPSCs contain provisions addressing environmental issues in petroleum operations, including the following:

a. 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;

b. 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;

c. 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;

d. prior to conducting drilling activities, to prepare a contingency plan for dealing with spills, blowouts, fires, accidents and emergencies resulting from petroleum operations;

e. upon expiry or termination of the agreement, to remove all equipment and installations from the contract area pursuant to an agreed abandonment plan; and

f. 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 pre-existing environmental conditions and approved in advance are also recoverable as supplementary costs.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i. Establishment

Foreign investors in the upstream oil and gas sector can invest through a foreign entity with an Iraqi branch. Establishment of a local entity is not required.

Under the terms of the PSCs and DPSCs, the entity designated as the ‘lead contractor’ is additionally required to establish and maintain an office in Baghdad.

ii. Anti-corruption

The main legislation in Iraq with respect to anti-corruption matters is contained in the Iraqi Penal Code. Article 310 of the Iraqi Penal Code provides:
Any person who gives, offers, or promises a public official or agent [a gift, benefit, honour or promise thereof to carry out any duty of his employment, or to refrain from doing so] is considered to be offering a bribe.

Any person who mediates for a person who offers or accepts a bribe in order to offer, seek, accept, receive or promise such bribe, is considered to be an intermediary.

The person who offers a bribe as well as the intermediary is punishable by the penalty prescribed by law for a person who accepts such bribes.

Article 19(2) of the Iraqi Penal Code defines a ‘public official’ as ‘any official, employee or worker who is entrusted with a public task in the service of the government or its official or semi-official agencies belonging to it or placed under its control’.

A person convicted of an offence under Article 310 is punishable by imprisonment for a term of up to 10 years plus a fine of up to 500 Iraqi dinars.

IX CURRENT DEVELOPMENTS

i Pending contract renegotiation

The recent significant decline in oil prices, combined with a need for Iraq to devote a significant portion of its budget to combat militants from the Islamic State, has created a significant strain on Iraq’s budget. As a result, as has been widely reported in the industry press, officials from the Ministry of Oil have contacted their IOC partners and asked them to 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 which have generally been decreased during previous rounds of renegotiations.

As this volume goes to press, the renegotiation process is still in its very early stages, but it appears likely to be a major area in 2017 for the Ministry of Oil and for IOCs operating in Iraq.

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.
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 a giant well worth 14 billion barrels of crude at the Shaikan field. 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 are 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 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. In concert with the low world market oil prices and the ongoing fight of Kurdish peshmerga and Iraqi army forces against the terrorist group Islamic State (IS) this has created a severe financial crisis in the KRI.

Just recently, and evidently due to the strained financial situation of the KRI, the central government and the KRG have again begun to jointly export crude oil from the Kirkuk fields to Ceyhan in Turkey. Further, the parties have taken up negotiations to finally reach a comprehensive revenue-sharing deal involving the entire oil and gas reserves of Iraq.

At the same time and after two years of IS controlling huge swathes of land in northern Iraq, this situation seems to be improving as well. After having reclaimed Kirkuk, peshmerga together with Iraqi army and coalition forces are closing in on the city of Mosul, the last major stronghold of IS in Iraq.

It is, however, doubtful whether the removal of IS from Iraqi territory will bring the desired stability to the region. Within KRI a separate power struggle is raging. Massoud Barzani’s term in office as President of the Kurdistan Region officially ended on 20 August 2015 with no legal framework acceptable to the different political parties that would allow for presidential elections at the current time. The Kurdistan Shoura Council has issued an opinion that Mr. Barzani should continue in office until such time as presidential elections are held, while opposing political parties are demanding that an interim president be appointed by the parliament.

It 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.

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 To date, the said federal law on oil and gas has not yet been passed.

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

3 Article 111 Iraqi Constitution.
4 Article 112(1) Iraqi Constitution.
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 that it deems illegal. The Supreme Court of Iraq, the country’s independent judicial body which interprets the Constitution and determines the constitutionality of laws and regulations, has not yet rendered a decision in the pending court proceedings initiated by the central government in 2012. However, in 2014, the Supreme Court of Iraq refused to grant the Ministry of Oil an injunction against the KRG prohibiting it from exporting crude oil independently. The Supreme Court of Iraq justified its decision 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’. This would contravene the judicial ‘context/norms’ and hence the decision must be made within the context of the ‘subject matter of the case’. While the KRG has publicised the decision as a major victory, in fact, only the final decision of the Supreme Court of Iraq, which has not yet been rendered, will have far-reaching implications. The ongoing oil and gas dispute between the KRG and the central government stems from the interpretation of the Constitution, which is quite unclear.

i Domestic oil and gas legislation

The Iraqi Constitution gives the regions the right to legislate on any matters that do not fall within the exclusive jurisdiction of the central 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

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.
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\textsuperscript{10} identified in subsection ii, \textit{infra}). The MNR shall encourage public and private sector investment in petroleum operations.\textsuperscript{11}

The central government in Baghdad asserts that the KOGL, as well as all petroleum contracts entered into by the KRG, 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. Payments were resumed in December 2014 but were halted again during the early months of 2015. Just recently the parties have taken up negotiations to finally settle this ongoing dispute.

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’. In its interpretation of the Iraqi Constitution and existing federal legislation, 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. This was later promulgated into law by the CPA pursuant to 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.\textsuperscript{12}

Accordingly, 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.\textsuperscript{13} All proceeds from any hydrocarbon activity in the KRI or related to that activity, including allocations from the federal budget which 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

\begin{itemize}
\item \textsuperscript{10} Article 4 KOGL.
\item \textsuperscript{11} Article 9(1) KOGL.
\item \textsuperscript{12} Section 5(4)(a) CPA 95.
\item \textsuperscript{13} Article 15 KOGL.
\end{itemize}
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 a barrel allocation for each province from which the revenues were derived.

ii Regulation

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

a the Iraqi Kurdistan parliament: the 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;\(^{14}\) it mainly formulates the general principles of petroleum policy, prospect planning and field development and approves petroleum contracts;\(^{15}\) and
d the Ministry of Natural Resources of the Kurdistan Region: the MNR oversees and regulates all petroleum operations in the KRI\(^{16}\) 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.\(^{17}\) 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.\(^{18}\) Nonetheless, judgments made against the government or against any of its employees in respect of acts undertaken in the course of duty or exclusively on account thereof are exempted.\(^{19}\) The same applies to awards of arbitrators.\(^{20}\)

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.

14 Article 4 KOGL.
15 Article 24(1) KOGL.
16 Article 6(1) KOGL.
17 Article 107(1) Iraqi Constitution.
18 Article 25(b) Riyadh Convention.
19 Article 25(c) Riyadh Convention.
20 Article 37 Riyadh Convention.
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.

Although a member of OPEC, Iraq is currently not subject to the organisation’s production and export quota.

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.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.22

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

a A signature bonus24 and a capacity-building bonus25 are payable by the contractor once the PSC becomes effective.

b The KRG has the right to participate in the PSC through one of its public companies with a stake of up to 25 per cent after commercial discovery.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.27

c The term of the PSC varies in accordance with advancement. The exploration period lasts for five years (comprising an initial sub-period of three years and a second sub-period of two years) and may be extended for a further two years.28 Upon commercial discovery, the development period extends to 20 years with two possible extension periods of five years each.29

21 Article 26 KOGL.
22 Article 24 KOGL.
23 The Model PSC is available at www.krg.org/pdf/3_krg_model_psc.pdf.
24 Article 32.1 Model PSC.
25 Article 32.2 Model PSC.
26 Article 4.1 Model PSC.
27 Article 4.3 Model PSC.
28 Article 6.2 Model PSC.
29 Article 6.10 and 6.12 Model PSC.
Preference is to be given by the IOC to local employment, subcontractors and materials.

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.

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. 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.

In the event of a commercial discovery, a production bonus is payable in addition to a recurring royalty (i.e., a portion of petroleum produced). Usually, the royalty rate for export crude oil and natural gas is set at 10 per cent.

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. The remaining ‘profit petroleum’ is split between the KRG (through its public company) and the contractor pursuant to the quotas stipulated in the PSC.

During the exploration period, the contractor may terminate the PSC at the end of each contract year. Once the development period has been entered into, the contractor has the right to terminate the PSC at any time.

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.

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.

30 Article 23.1 Model PSC.
31 Article 22.2 Model PSC.
32 Article 23.7 Model PSC.
33 Article 6.3 Model PSC.
34 Article 7.1 Model PSC.
35 Article 32.3 and 32.4 Model PSC.
36 Article 24.1 Model PSC.
37 Article 25.3 and 25.4 Model PSC.
38 Article 26 Model PSC.
39 Article 45.3 and 7.4 Model PSC.
40 Article 45.4 Model PSC.
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, supra), 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 of approximately 550,000bpd 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

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

41 Article 16.15 Model PSC.
42 Article 30 KOGL.
43 Article 39.2 Model PSC.
44 Article 39.6 Model PSC.
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

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 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:

a The IOC, each contracting entity, its affiliates and any subcontractor are exempt from all taxes as a result of their income, assets, and activities under the PSC effectively for the entire duration of the PSC, including but not limited to taxes on income from moveable capital, any taxes on capital gains, and any fixed taxes on transfers. 48

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.
48 Article 31.1 Model PSC.
Iraqi Kurdistan

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.\(^{52}\)

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.\(^{53}\) 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.

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 further 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 years, a number of IOCs have been required to pay all labour-related taxes and social security contributions for 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.

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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.
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 remediying pollution, an IOC is required under the PSC to adhere to prudent international petroleum industry practice with regard to environmental protection as well as applicable laws. IOCs are also required to make payments towards an Environment Fund.

The KRG Law of Environmental Protection and Improvement No. 8/2008 regulates environmental matters such as the protection of water, soil, air and biodiversity, and is applicable to oil and gas operations. In accordance with Articles 4 to 6 of the Law, the Ministry of Environment in the KRI established an Environmental Protection and Improvement Council to oversee and supervise all environmental matters. In 2010, an independent Environmental Protection and Improvement Board was established in the KRI by Law No. 3/2010, which replaced the Environmental Protection and Improvement Council and has assumed the oversight and supervisory role for the enforcement of Law No. 8/2008.

In addition to specific obligations related to standards for the protection of water, soil, air and biodiversity, any person conducting any activity that has an environmental impact must obtain prior approval from the Environmental Protection and Improvement Board.

Non-compliance with the obligations of the Environment Law may result in no less than one month of imprisonment or fines of between 150,000 and 200 million Iraqi dinars, or both. In addition to the specific penalties provided for in the Law, anyone who causes environmental damage shall be subject to civil compensation and responsibility for removing or correcting 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 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.

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. 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.

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.
59 Article 38.1 Model PSC.
60 Article 46 KOGL.
The procedure for registering a branch entails submission by the parent company of the following documents legalised up to the level of the Iraqi consulate in the country of issuance:

a) corporate documents of the IOC (certificate of establishment, commercial register extract, statutes, etc.);

b) letter of intent or shareholders’ resolution approving the establishment of the branch and an undertaking that the IOC shall assume all liabilities and obligations of the branch;

c) power of attorney granted to the person to be appointed manager of the branch plus a copy of his or her passport;

d) evidence of the business premises in KRI; and

e) last audited financial statements of the IOC.

The above documents are to be submitted to the Register of Companies along with a decision by the MNR approving such registration. In addition to the above, 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 and to pay any subcontractor and its expatriate personnel in foreign currency.

iii Preference to local resources

In addition to the KOGL requiring that IOCs give preference to local manpower from the KRI and other parts of Iraq provided that they have the necessary qualifications, the same obligation also applies to subcontractors. This is also mirrored in both the Iraqi Labour Law applicable in the KRI and the Model PSC. The IOC is required to provide training to local employees and, where possible, ‘to maximise knowledge transfer to the people of the region’. Training may include scholarships, funding for education and secondment of government employees to the IOC. The IOC must provide a training plan and advance funding to the

61 Article 29.4 Model PSC.
62 Article 29.9 Model PSC.
63 Article 44(1) KOGL and 23.1 Model PSC.
64 Article 45 KOGL and 23.4 Model PSC.
65 Article 45 KOGL.
66 Article 23.2 Model PSC.
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.67

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.68 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.69 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 on doing business in Kurdistan remain, based on the above it seems reasonable to exempt the KRI from the general corruption ranking of Iraq.

IX  CURRENT DEVELOPMENTS

In particular two factors have characterised the development of the KRI hydrocarbons industry.

On the one hand, the relative security of the region (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.

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.

67  Article 23.3.1 Model PSC.
68  Article 23.3 Model PSC.
69  Article 44(2) KOGL.
Both factors have in the past been redefined.

The promise of ongoing security in the region was brought into question by macro-political events in the surrounding countries, and, even more, by the massive expansion of the terrorist network IS into vast areas of northern Iraq.

The lack of technical midstream capabilities was 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 IS 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 has allowed the KRG to exploit the vast oil resources of Kirkuk as well as enabling it to transport oil through the central Iraqi pipeline network to Iraq's south. In addition to that, KRI and Iran are currently negotiating the terms of a second large pipeline capable of transporting up to 250,000bpd of oil from KRI to Iran, thus creating an alternative route for the Kurdish oil and reducing the singular dependency from Turkey.

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 at record low world market prices.

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. Due 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.

The financial crisis has indeed promoted and enabled real economic reforms in the KRI. Salaries of government officials have been cut across the board and several public subsidies have been removed or reduced. At the same time efforts are under way to reduce costs of electricity production and distribution and to introduce e-government facilities to streamline administrative processes and to crack down on corruption.

Further and evidently also due to the strained financial situation of the KRI, the central government and the KRG have agreed to and again begun to jointly export crude oil from the Kirkuk fields to Ceyhan in Turkey. The parties have taken up ensuing negotiations to finally reach a comprehensive revenue-sharing deal involving the entire oil and gas reserves of Iraq. It remains to be seen whether the central government and the KRG will be able to find a formula for the mutual exploitation of the entire Iraqi oil reserves. But there is an expectation that the Kurdish peshmerga, together with Iraqi army and international coalition forces, will sweep IS from its last Iraqi stronghold in Mosul in the near future, and there is a glimmer of hope that the prospects for the KRI will soon look brighter again.
Chapter 14

ITALY

Roberto Leccese

I INTRODUCTION

In 2014 natural gas production in Italy reached 7.28 billion cubic metres and oil production reached 5.75 million tonnes.

The reserves data as at 31 December 2014 (including proved, probable and possible ones, according to the relevant international classification) are set forth in the table below.

<table>
<thead>
<tr>
<th></th>
<th>Proved (Smc x 106)</th>
<th>Probable</th>
<th>Possible</th>
<th>% Proved</th>
</tr>
</thead>
<tbody>
<tr>
<td>Northern Italy</td>
<td>2,463</td>
<td>2,352</td>
<td>26</td>
<td>4.7%</td>
</tr>
<tr>
<td>Central Italy</td>
<td>526</td>
<td>1,379</td>
<td>397</td>
<td>1.3%</td>
</tr>
<tr>
<td>Southern Italy</td>
<td>19,993</td>
<td>22,015</td>
<td>10,714</td>
<td>32.1%</td>
</tr>
<tr>
<td>Sicily</td>
<td>1,302</td>
<td>1,043</td>
<td>643</td>
<td>2.9%</td>
</tr>
<tr>
<td>Total onshore</td>
<td>24,284</td>
<td>26,790</td>
<td>11,781</td>
<td>41%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th></th>
<th>Proved (Smc x 106)</th>
<th>Probable</th>
<th>Possible</th>
<th>% Proved</th>
</tr>
</thead>
<tbody>
<tr>
<td>Zone A</td>
<td>20,251</td>
<td>14,344</td>
<td>7,569</td>
<td>40%</td>
</tr>
<tr>
<td>Zone B</td>
<td>5,342</td>
<td>5,951</td>
<td>2,494</td>
<td>10.7%</td>
</tr>
<tr>
<td>Zone C+D+F+G</td>
<td>3,836</td>
<td>12,691</td>
<td>2,447</td>
<td>8.2%</td>
</tr>
<tr>
<td>Total offshore</td>
<td>29,429</td>
<td>32,985</td>
<td>12,600</td>
<td>59%</td>
</tr>
<tr>
<td>Total</td>
<td>53,713</td>
<td>59,774</td>
<td>24,381</td>
<td>100%</td>
</tr>
</tbody>
</table>

1 Roberto Leccese is a partner at Ughi e Nunziante – Studio Legale. The information in this chapter is accurate as of November 2015.
It is worth noting that 59 per cent of the total national gas is located offshore, while nearly 90 per cent of oil reserves are located onshore, and for the most part in the Basilicata region.

<table>
<thead>
<tr>
<th>Oil (Ktonnes)</th>
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<tbody>
<tr>
<td></td>
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<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Proved</td>
</tr>
<tr>
<td>Northern Italy</td>
</tr>
<tr>
<td>Central Italy</td>
</tr>
<tr>
<td>Southern Italy</td>
</tr>
<tr>
<td>Sicily</td>
</tr>
<tr>
<td>Total onshore</td>
</tr>
</tbody>
</table>

<p>| |</p>
<table>
<thead>
<tr>
<th></th>
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<tbody>
<tr>
<td></td>
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<tr>
<td></td>
</tr>
<tr>
<td>Proved</td>
</tr>
<tr>
<td>Zone B</td>
</tr>
<tr>
<td>Zone C</td>
</tr>
<tr>
<td>Zone F</td>
</tr>
<tr>
<td>Total offshore</td>
</tr>
<tr>
<td>Total</td>
</tr>
</tbody>
</table>

As at 31 December 2014, 117 exploration licences (of which 95 are onshore and 22 offshore) and 201 for production (of which 132 onshore and 69 offshore) are in force on Italian territory. Emilia Romagna, Lombardy and Basilicata are the regions with the highest number of onshore mining titles. In 2014 drilling activities were carried out on 12 wells, most of which were in offshore licences.

In March 2013 the Italian government approved the new National Energy Strategy (SEN) focusing, among other things, on reducing dependency on imports of hydrocarbons. In short, the SEN’s objective is to increase national hydrocarbon production by 2020 so as to reduce the energy bill by about €5 billion per year, by exploiting subsoil resources (mainly natural gas) according to sustainable criteria.

Significant amendments to the oil and gas legislation have been provided by the ‘Unlock Italy’ (Sblocca Italia) Law-Decree No. 133 of 12 September 2014, which came into force on 13 September 2014 and was subsequently amended and converted into Law No. 164 dated 11 November 2014 (in the Italian system, law decrees are acts adopted by the government having the same effects as a law enacted by the parliament, which need to be ratified and may be amended by the latter within the next 60 days).

Law-Decree 133/2014 was implemented by Decrees of the Ministry of Economic Development (MED) dated 25 March 2015 and 15 July 2015 which now set forth the new legal framework relating to liquid and gas hydrocarbons prospection, exploration and production activities in Italy.

II LEGAL AND REGULATORY FRAMEWORK

The Italian regime of hydrocarbon exploration and exploitation both onshore and offshore is based on the principle that mining resources are compulsorily owned by the state. However, the government does not exploit such resources directly; it awards private operators special permits for this task, after having verified their technical and economic capabilities.

After the granting of the permit, general surveillance activity is carried out by the government consisting of constant checks to ensure over good government of the field, the safety of workers and third parties and compliance with all the relevant legislation with reference to prospecting, exploration and production.

i Domestic oil and gas legislation

The most relevant legislation ruling the hydrocarbons exploration and production industry in Italy is the following:

a Royal Decree No. 1443, 29 July 1927, as amended, *inter alia*, by Law No. 6 of 1957 (the Mining Law, which sets forth the general principles that apply to the mining sector);

b Law No. 9, 9 January 1991 (providing a new national energy plan);

c Legislative Decree No. 625, 25 November 1996 (provisions for the granting and the exercise of authorisations related to hydrocarbon prospection, exploration and production);

d Legislative Decree No. 164, 23 May 2000 (common regulation of internal market of natural gas);

e Legislative Decree No. 239, 23 August 2004 (reorganisation of the energy field);

and

f Legislative Decree No. 152, 3 April 2006 (the Environment Code).

ii Regulation

The MSE, General Department of Energy and Mineral Resources, regulates almost all aspects of the exploration and exploitation of hydrocarbons. The MSE assesses all applications and grants licences to prospect, explore or produce hydrocarbons as appropriate.

A consulting technical committee, the National Mining Office for Hydrocarbons and Geothermal Resources (UNMIG) is responsible for granting licences and for the control of activities during the exploration and exploitation of hydrocarbons. The jurisdiction of the MSE extends over all mainland Italy, its territorial waters and the continental shelf up to a water depth of 200m and, in some areas, deep waters up to 1,000m.

The five Italian autonomous regions (Friuli Venezia Giulia, Sardinia, Sicily, Trentino Alto Adige and Valle d’Aosta) have some competency on onshore areas but not on the surrounding offshore areas, which fall under the jurisdiction of the central government.
iii Treaties

Italy is a signatory to a number of international treaties and conventions that affect the oil and gas industry including the 1958 New York Convention on the Recognition and Enforcement of Foreign Arbitral Awards and the Energy Chapter Treaty (ECT) of 1994 providing for, among other things, the promotion and protection of foreign investments, dispute resolution mechanisms, as well as a number of bilateral and multilateral investment treaties and conventions. In January 2015 Italy withdrew from the ECT effective as at January 2016, provided that foreign investors may resort to the dispute resolution procedures provided for in the ECT for 20 years from the date when the withdrawal takes effect.

Italy is a party to tax treaties on the avoidance of double taxation with a number of other countries.

Italy is also a party to several conventions with other Mediterranean states providing for the limits of the territorial sea, the exclusive economic zone and the continental shelf.

A full list of treaties and conventions to which Italy is a signatory is available at www.esteri.it/mae/it/ministero/servizi/stranieri/elenco_paesi.htm and the relevant texts are available at http://itra.esteri.it/itrapgm/.

III LICENSING

Pursuant to Italian law, hydrocarbon exploration and production activities may be carried out under different kinds of licences awarded by the MSE, namely:

- **Prospection permits**, granting the non-exclusive right to carry out non-disruptive ground-sounding activities, which are done by testing and measuring certain physical features of the underground by means of specific appliances (sonars, electronic sounders, etc.);
- **Exploration permits**, granting the exclusive right to perform exploration activities, such as drilling and other ground-disruptive practices (such as minor underground detonations) for the purpose of accurately detecting and locating gas and oil fields;
- **Production concessions**, granting the exclusive right to production activities, such as drilling of production wells and hydrocarbon extraction; and
- **Sole concessions granting the exclusive right to perform both exploration and production activities.**

In order to obtain both a prospection permit and an exploration permit, an application has to be filed with the MSE that verifies the technical and economic capabilities of the applicant.

The prospection permit does not automatically grant the right to be preferred for the issuance of the subsequent exploration permit.

Exploration permit applications are published in the *Official Journal of Hydrocarbons and Geothermy* and must be notified to the European Commission for publication in the *Official Journal of the European Union*.

As far as exploration permits are concerned, if other applications are filed by other entities within three months, they shall be considered ‘contender applications’.
and a competition sub-phase starts. The MSE shall select the best application under competition mainly on the basis of the completeness and rationality of the proposed exploration programme and of the technical and economic soundness of the applicant.

As stated above, licences may be granted only to entities with adequate technical capability and financial resources.

As far as the technical requirements are concerned, among other things, the applicant has to:

- indicate the people who will be responsible for each ‘department’ as well as the number of employees, consultants and contractors;
- provide evidence that they are actually and permanently employed;
- describe the internal decision-making process;
- provide details as to its technical skills (with specific reference to geology and geophysics, oilfield management, production technology, health and safety, environment, innovation and education);
- in case it has the above mentioned skills through external suppliers, indicate the supplier selection process, the quality assessment procedure and the experience in the relevant supervision; and
- provide details with reference to health, safety, environment and risk management.

As for the financial requirements, the applicant needs to prove that it has a share capital of no less than €120,000 and to provide, among other things:

- a copy of the financial statements for the past three years and with the consolidated financial statement (if any);
- a copy of the last financial statements (or pro forma financial statements) of the parent company (or of the company belonging to the same group) that issues the guarantees or the loans to the applicant (if any);
- a statement of its authorised representatives related to:
  - the turnover of the last three years (both general and specific);
  - the applicant’s net worth (should this be below zero, it must be proved that the proper actions provided by the law were taken);
  - the working capital or short-term debt ratio (should this be below one, then it is necessary to give evidence that the financial needs of the applicants are duly covered by means of short-term loan agreements with parent/same group companies or with banks);
  - the net debt or net worth ratio (should this be over 75 per cent, then it is necessary to give evidence that the applicant is capable of repaying its debt through a repayment plan showing the cash flows, or with a loan agreement without expiration date with parent or same group companies); and
  - information related to the entity or individual holding the majority of votes in the shareholders’ meeting, or enough votes to have a dominant influence over the shareholders’ meeting, or capable of having a dominant influence over the applicant due to contractual arrangements with the latter.

Moreover, a parent company guarantee is required in order to cover, among other things, the estimated decommissioning expenses (see below), unless the applicant has a net
worth of over €10 million or formal guarantee engagements are given by parent or same group companies having a net worth of over €10 million.

Production concessions may be granted to the holder of an exploration permit which, after drilling one or more wells, has found liquid or gaseous hydrocarbons.

A production concession will only be granted if the productive capacity of the wells and other geo-mining data suggest the development of the prospect will be economically and technically viable.

For the purpose of simplifying the awarding procedure, making it no longer necessary to file both an application for the exploration permit and (in case hydrocarbons are found) another one for the production concession, Law-Decree 133/2014 has introduced the ‘sole concession’ which shall be sufficient both for exploration and for production-related activities, provided that the transition from the exploration phase to the production phase has to be authorised by the MED and that all the relevant environmental clearances need to be obtained prior to the performance of the relevant works.

Upon filing of a sole concession application, a three-month term for top-file application applies, as for exploration permit applications.

However, at the time of writing it is still not possible to file an application for a sole concession. As a matter of fact, Law-Decree 133/2014 dictated, as a precondition for such filing, that the MED provide a detailed map of the areas in which the hydrocarbons prospection, exploration and production activities are allowed and no such map has been provided by the MED so far.

Insofar as the proposed exploration or production may endanger the environment, an environmental monitoring phase may be required as a precondition to the award of the research permit and the production concession, as the case may be (see below).

The prospection permit expires after one year from the issuance.

Exploration permits last six years (subject to two renewals of three years each and, under specific circumstances, one renewal of one year). During its term, the grantee is obliged to begin the planned exploration activity and to perform it according to the schedule it has proposed when it lodged the application. If hydrocarbons are found, the MSE must be notified immediately.

Production concessions last 20 years (subject to one renewal of 10 years and further renewals of five years each), subject to the completion of the planned works and of any relevant prescription.

As far as the sole concession is concerned, the research activity phase will last six years, subject to two renewals of three years each, and the production phase will last 30 years subject to one or more renewal of up to 10 years.

Operators that do not hold any licences may apply to obtain a pre-qualification, consisting in the MED’s acknowledgment that they are eligible for the award of same. In order to pre-qualify, the applicant has to give evidence that it has all the relevant requisites (general, financial and technical). Upon pre-qualification, the applicant shall no longer have to give evidence of its requisites when applying for the award of a licence.

The pre-qualification expires two years after granting.

The holders of a licence have to keep constantly in touch with the UNMIG, in order to communicate various types of information and for compliance with regulations.

A rental fee is due to the state both for exploration and for production.
Along with the rental fee, a royalty is due to the state on a yearly basis in the production phase. The relevant amount varies depending on whether the production is onshore or offshore. The relevant calculation is performed on the basis of the average selling price of production, within the relevant period, net of the specific deduction as reported in the table below.

For plants located on land, an additional royalty is to be paid as a contribution to the Hydrocarbon Fund, which is due to reduce the fuel price in the region in which the plant is located.

For offshore plants, an additional royalty is to be paid as a contribution to increase environment and safety protection.

<table>
<thead>
<tr>
<th>Royalty</th>
<th>Onshore</th>
<th>Offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil, condensate</td>
<td>7% + 3% additional rate as a contribution to the Hydrocarbon Fund</td>
<td>4% + 3% additional rate for environment and safety</td>
</tr>
<tr>
<td>Natural gas</td>
<td>7% + 3% additional rate as a contribution to the Hydrocarbon Fund</td>
<td>7% + 3% additional rate for environment and safety</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Royalty allowance</th>
<th>Onshore</th>
<th>Offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>Liquid hydrocarbons</td>
<td>up to 20,000 tonnes</td>
<td>up to 50,000 tonnes</td>
</tr>
<tr>
<td>Natural gas</td>
<td>up to 25MSm³</td>
<td>up to 80MSm³</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Deduction</th>
<th>Onshore</th>
<th>Offshore</th>
</tr>
</thead>
<tbody>
<tr>
<td>Crude oil, condensate</td>
<td>€ 15.49/tonnes</td>
<td>€ 30.98/tonnes</td>
</tr>
</tbody>
</table>

When licences are held jointly, one of the partners must be appointed by the other(s) as the sole representative, which will be entrusted to deal with the competent public bodies.

Partners are jointly liable towards the public administration and third parties for all obligations arising from their joint activity.

It is customary for the partners (albeit not strictly necessary) to enter into a joint operating agreement (JOA).

In Italy JOAs generally have a standard structure based on a format provided by the Italian Mining Association. Such format is not binding and partners are free to amend it or to adopt alternative contractual means including joint venture agreements governed by laws other than Italian law.

The JOAs generally provide for bodies that adopt and implement all relevant decisions (e.g., operating committees and technical committees). One of the partners
(usually, the one appointed as ‘sole representative’ in the application phase) is appointed as the ‘operator’.

The operator performs the exploration, drilling and extraction of hydrocarbons in accordance with the operating programmes and the relevant budgets resolved upon and approved by the other partners. As a rule, the operator decides autonomously how to perform its activities and which means are the most suitable for each operation; it also acts on behalf of the other partners.

JOAs generally contain an annex providing for an accounting procedure according to which costs and revenues are shared among the partners. The accounting procedure specifically provides which costs and which revenues have to be charged or credited, as the case may be, by the operator to the other partners.

Italian law acknowledges the strategic nature of the infrastructures for the import, processing and storage of hydrocarbons and provides that mining titles may amend town or urban plans, where the latter are inconsistent with the former, thus resulting in the establishment of expropriation constraints. As a result, mining titles may amend town or urban plans, where the latter are inconsistent with the former, thus resulting in the establishment of expropriation constraints.

When an exploration permit is granted, the landowner cannot oppose the performance of the planned exploration. On the other hand, the holder of the exploration permit has to compensate the landowner for any damage or loss he has suffered because of the exploration. The landlord has the right to request a deposit (i.e., an amount of money to be refunded to the holder of the exploration permit after the work is completed if the landlord has suffered no loss). The amount of the deposit has to be agreed upon by the holder of the exploration permit and the landlord.

When a licence is granted, the licensee has the right to operate on the land falling within the perimeter of the licence. To prevent any losses to the landowners (in addition to a landowner’s right to ask for a deposit as explained above), the licensee has to either enter into a lease agreement or agree upon a lump sum (una tantum) payment for the whole duration of the permit.

Licences terminate by expiry (of the relevant term of effectiveness), voluntary return (if the assignee does not have, for example, the financial means to carry out the planned works) and depletion (which occurs when the layer is depleted).

They may also be revoked in the cases provided by the law (such as non-performance of the planned works, or unjustified interruption of production).

IV PRODUCTION RESTRICTIONS

Exploration and production activities falling within certain areas of the Mediterranean Sea are subject to certain limitations and prohibitions.

In particular, certain areas of the North Adriatic Sea (‘A’ marine zone) were frozen in the 1990s owing to the risk of subsidence. Such suspension was provided by different subsequent law provisions, such as:

a Law 206/1995, which provided for the suspension of production activities until an environmental impact assessment was carried out by the Ministry of the Environment and the Veneto region over the relevant area;
Law 179/2002, amending Article 4 of Law 9/1991, which introduced a prohibition for all prospection, exploration and production activities in the Gulf of Venice; and

Law Decree 112/2008, which provided that the prohibition contained in Article 4 of Law 9/1991, as amended, would remain in place until verification, on the part of the government, of the actual risk of subsidence, based on new and updated studies that the holders of exploration permits and production concessions had to submit, using the most conservative assessment methods and the best available production technologies.

In derogation from the above mentioned limitations and in order to avoid that the solidity of the hydrocarbon deposits falling in this area might be harmed by third parties authorised by Slovenian or Croatian public authorities, Law-Decree 133/2014 entrusted the MED with the power of granting temporary experimental concessions.

In 2010, Legislative Decree No. 128 of 29 June further prohibited exploration and production activities within:

a. the perimeter of ‘protected areas’ (i.e., sea and coastal areas which are protected, for environmental purposes, pursuant to national or regional laws or in execution of international treaties or agreements);

b. the sea areas located within 12 nautical miles from the outside perimeter of the above mentioned protected areas; and

c. the sea areas located within 12 nautical miles of the Italian coastline.

With Ministerial Decree dated 9 August 2013 the MSE provided an updated picture of ‘marine areas’ open to the presentation of new applications and redefined certain offshore areas (‘E’ marine zone).

The marine areas in relation to which it is possible to submit new applications for the prospection and exploration of hydrocarbons are those reported in the map published on http://unmig.mise.gov.it/unmig/cartografia/zone/zone.asp.

There are no restrictions on the export of natural gas or oil.

V ASSIGNMENTS OF INTERESTS

Licences may be assigned to third parties. However, a preliminary authorisation must be issued by the MSE upon the assignor’s request. The final authorisation is issued by means of a ministerial decree after the notarial deed of assignment is notified to the MSE within six months of the preliminary authorisation. The MSE may hear from the other co-owners, if any.

JOAs usually provide that each partner’s share (and the relevant contractual relation with the other partners) may be assigned to third parties with the written consent of the other partners, which cannot be unreasonably withheld. However, if the assignee is a subsidiary, there is no need to obtain such prior consent.

Within 30 days of communication of the assigning partner, the other partners may exercise a pre-emption right. No pre-emption right is provided in case of assignment to a subsidiary.
No specific provisions are set forth by the relevant legislation in case of change of control of the holder of the licence. JOAs generally do not provide for any change of control clause either.

VI TAX

Under Italian law, upstream oil and gas operators are subject to the following tax regime.

i General corporate income tax (IRES)
Companies that are resident in Italy are subject to IRES on their worldwide income, while Italian branches (permanent establishments) of foreign companies are taxed only on their Italian-sourced income. The IRES rate is currently set at 27.5 per cent.

All costs related to oil and gas exploration in Italy are deductible from the taxable income.

With particular reference to amortisation, a specific rule applies to oil and gas distribution and transportation companies, providing that such companies have to calculate tax amortisation of goods used for distribution and transportation activities at an amount not higher than the one resulting from the division of the purchase price by the useful life as established by the Italian Authority for Gas and Electricity.

An additional surcharge tax (‘Robin Hood’ tax) is payable by companies operating in the oil and gas sector with revenues exceeding €3 million and taxable income exceeding €300,000 with reference to the previous year. The Robin Hood tax is due at the 6.5 per cent of IRES taxable basis.

Under certain circumstances, a further additional surcharge tax is provided for companies operating in the oil and gas sector with a market capitalisation of over €20 million, starting from fiscal year 2009 and until the end of fiscal year 2028. The relevant rate is currently set at 4 per cent.

For IRES purposes, losses may be carried forward with no time limitation and deducted from the income of the following period for a total amount equal to 80 per cent of the taxable income (such limit does not apply to losses incurred in the first three years of activity).

ii Regional tax on productive activities (IRAP)
Resident and non-resident companies are subject to IRAP on their Italian-sourced income. The IRAP general rate is currently set at 3.5 per cent, but each Italian region may vary such rate up to 0.9176 basis points.

IRAP taxable basis is the net value of production, equal to the value of production minus the cost of production (plus or minus certain other adjustments provided for by the law).

iii Value added tax (VAT)
With reference to the oil and gas sector the standard rate of 21 per cent is generally applicable, while a 10 per cent rate is applicable to the following cases:
a gas, methane gas and liquefied petroleum gas to be directly put into the pipeline networks in order to be delivered or supplied to enterprises that use it to produce electricity;
b crude oil, combustible oil and aromatic extracts used to generate electricity, directly or indirectly, as long as power is not below 1kW; crude oil, combustible oil (except for fluid combustible oil for heating) and filter sands, remnants of the processing of lubricant oil, containing more than 45 per cent in weight of oil product, to be used directly in boilers and kilns; combustible oil used to generate motive power directly with stationary engines in industrial, agricultural-industrial plants, laboratories, building yards; and combustible oil other than the special ones to be converted into gas to be put in the civic grid system; and
c mineral oil not refined from the primary distillation of raw natural oil or from the processing by plants that convert mineral oil into chemical products of a different nature, with a flash point lower than 55°C, where the distillate at 225°C is lower than 95 per cent in volume and at 300°C it is at least 90 per cent in volume, to be converted into gas to be put into the civic grid system.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

An environmental monitoring phase may occur if the proposed exploration or production project could endanger the environment. In these circumstances, the competent public bodies determine whether the project will have a substantial impact on the environment and prescribe the measures to be taken in order to minimise the relevant environmental impact (VIA).

Should a VIA procedure be required for the proposed project, it shall be included in the process aimed at awarding the licence. In order for the VIA procedure to be completed, the law provides a term of 150 days, which may be extended by another 60 days in case of particularly complex matters. Within such term, a final decision shall have to be taken which may be negative or positive and, in case of the latter, with or without prescriptions aimed at minimising or compensating the environmental impact of a project. Under given conditions, additional ‘compensatory measures’ (including contributions to local stakeholders) may also be agreed upon between the private operator and the relevant public bodies.

As stated above, the positive outcome of the VIA procedure is an integral part of the licensing process and it is a necessary condition for its completion. Therefore, pending the former, the latter is temporarily suspended. Should the outcome of the VIA procedure be negative, the relevant permit will most likely be denied.

The VIA procedure is provided for mainly by the Environmental Code.

As a rule, the environmental assessment procedures fall within the jurisdiction of the Ministry of the Environment.

Following the award of the relevant licence, certain environmental controls related to mining activities are also carried out by the UNMIG.

By Law No. 68 of 22 May 2015, published on the Official Journal of 28 May 2015, certain new crimes against the environment have been introduced in the Italian legal system, such as environmental pollution, environmental disaster,
hindering of environmental controls, failure to restore damaged areas, etc. In particular, environmental pollution and environmental disaster crimes are punished respectively with imprisonment going from a minimum of two and a maximum of six years for pollution, while environmental disaster is sanctioned with imprisonment going from five to 15 years. In some cases Law No. 68 also sets out fines of up to €100,000 and provides for the prohibition to enter into agreements with public bodies.

As stated above, Legislative Decree of 18 August 2015 No. 145 established additional safety standards in offshore oil and gas production activities and aims to reduce the occurrence of major accidents and limit their consequences.

Among other things, Legislative Decree 145/2015:

\( a \) establishes the Offshore Operations Safety Committee which will be in charge of liaising with the operators and with other public entities, both at national and international level (e.g., the European Union Offshore Oil and Gas Authorities Group – EUOAG) in order to monitor the compliance with the provisions of the same;

\( b \) provides additional elements to be taken into account by the MED when assessing the technical and financial capability of an applicant in case of offshore operations;

\( c \) requires operators to adopt a number of procedures, policies, measures and schemes to reduce the risk of a major accident to an acceptable level (e.g., corporate major accident prevention policy, safety and environmental management system, report on major hazards, etc.).

In case of infringements of its provisions Legislative Decree 145/2015 provides financial penalties ranging from €30,000 to 150,000, depending on the infringement, and the ancillary measure of suspension of activities, from 15 days to six months. It also provides that operating production installations or connected infrastructures without having been appointed as operator by the MED is a criminal offence, punishable with a three-year imprisonment and a fine of €50,000 to €150,000.

The provisions of Legislative Decree 145/2015 shall apply as of 19 July 2016 with reference to owners, operators of planned production installations and operators planning or executing well operations and as of 19 July 2018 with reference to existing installations. Moreover, the rules for the Offshore Operations Safety Committee’s functioning shall be set forth in a decree of the President of the Council of Ministers which, at the time of writing, has not yet been adopted.

Prospection, exploration and production activities (both onshore and offshore) require the applicant to prove that a sufficient economic guarantee is in place in order to cover the risk of an accident during such activities; such guarantee has to be proportioned to the worst accident that could occur in the various scenarios envisaged in the risk analysis related to the project for which the authorisation is requested.

The documents evidencing the existence of the above-mentioned guarantee have to be filed together with the application for the authorisation related to the works or activities to be performed.

To determine the amount of the guarantee, the applicant has to perform a risk assessment and study, taking into account all the risks reasonably related to the activities
for which the authorisation is requested (affecting persons, properties, environment) and to set forth the possible mitigation actions.

Based on the above analysis, the applicant has to perform an analysis of the costs related to the worst possible accident envisaged in the risk analysis.

The risk analysis and the related cost analysis are then filed with the MED, together with the evidence of existence of a sufficient guarantee covering the potential accident associated costs.

With reference to drilling activities, the amounts of the guarantees may not be lower than the thresholds indicated in the table below.

<table>
<thead>
<tr>
<th></th>
<th>Total onshore guarantee (€)</th>
<th>Total offshore 'shallow' (jack-up) guarantee (€)</th>
<th>Total offshore 'deep' (floater) guarantee (€)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gas and condensates in scaly clay</td>
<td>50,000</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Gas and condensates</td>
<td>50 million</td>
<td>150 million</td>
<td>200 million</td>
</tr>
<tr>
<td>Oil with a capacity of up to 1,000 barrels/day</td>
<td>100 million</td>
<td>250 million</td>
<td>250 million</td>
</tr>
<tr>
<td>Oil with a capacity of up to 5,000 barrels/day</td>
<td>200 million</td>
<td>300 million</td>
<td>300 million</td>
</tr>
<tr>
<td>Oil with a capacity exceeding 5,000 barrels/day and/or under high-pressure/temperature conditions</td>
<td>300 million</td>
<td>500 million</td>
<td>500 million</td>
</tr>
</tbody>
</table>

The existence of the guarantee may be proved through an insurance policy or bank guarantee or other forms of guarantee accepted by the MED.

In case of jointly held mining titles, it is possible for the sole representative to prove the existence of the guarantee, without prejudice to the joint liability of all the co-holders for the obligations associated with the mining title.

Upon termination of a licence for any reason, the holder is bound to ensure the decommissioning of disused installations (including drilled wells, pipelines, etc.), to recover the related areas and to remove any associated equipment within two years.

A decommissioning programme setting out in detail the actual measures to be taken and the relevant work to be performed must be prepared by the licensee.

As stated above, when applying for the licence, specific guarantees must be provided by the applicant to cover, among other things, the estimated decommission expenses, unless its net worth exceeds €10 million or formal guarantee engagements are given by parent or same group companies having a net worth of over €10 million.

**VIII FOREIGN INVESTMENT CONSIDERATIONS**

i Establishment

Exploration and production licences may be granted to individuals and companies established in Italy, in the EU and in foreign countries that apply reciprocity to their exploration industry, provided that, as stated above, they have adequate technical capability and financial resources.
ii Capital, labour and content restrictions

The Italian legal system does not provide specific rules in relation to the hiring of employees in the oil and gas field. As for any other industry, there are no restrictions for workers from other EU countries, while non-EU citizens may be hired only if a work permit is obtained.

Some statutes regarding health and safety protection measures apply to those who are occupied in the oil and gas industry.

Legislative Decree 624/1996 sets out who is liable (employer, executive and appointee) in the company structure for each task.

The employer has a duty, _inter alia_, to prepare and to periodically update a safety and health document (SHD), which must identify all the possible sources of danger in the work areas and all the most appropriate measures to minimise them. The SHD and the relevant updates have to be supplied to the UNMIG, which is in charge, among other things, of carrying out all the necessary safety, environmental and technical controls.

Directorial Note of 21 February 2014 provides for high safety standards for workers and infrastructure and establishes the specific requirements for those who intend to operate in deep water.

iii Anti-corruption

Pursuant to Legislative Decree 231/2001, if certain crimes are committed in the interest, or for the benefit, of a company by natural persons holding representative, administrative or managerial positions in such company (as well as by natural persons working under the direction or supervision of said persons), the company itself may be held liable under given conditions.

Such liability is in addition to that (of criminal nature) of the natural persons who materially commit the crime and may result in the company being subject to fines or penalties consisting, among other things, in the suspension or withdrawal of licences and concessions (including research permits and production concessions), the prohibition to enter into agreements with public bodies, the debarment from the business, the exclusion from or revocation of public loans and grants.

Among the crimes that may give rise to the liability of a company, it is worth mentioning those committed in the course of dealing with public bodies (e.g., bribery or fraud), certain corporate crimes (e.g., fraudulent corporate communications or illegal allocations of net income and reserves) and those consisting of breach of labour health and safety provisions.

The company may avoid such liability by adopting certain internal organisational and management policies aimed at preventing such crimes.

The decision as to whether or not to adopt and implement such policies and how to do so falls within the discretion and responsibility of the managing body. If a crime is committed and, as a consequence, the company is held liable pursuant to Legislative Decree 231, the directors may be held liable for negligence.
IX CURRENT DEVELOPMENTS

As stated above, on 13 September 2014 Law-Decree 133/2014 came into force. More detailed rules were adopted by the MSE (namely Ministerial Decree dated 25 March 2015 and Directorial Decree dated 15 July 2015). One of the main innovations provided by the Italian legislator is the introduction of the sole concession.

However, as further stated above, at the time of writing applying for a sole concession is subject to the MED to provide a detailed map of the areas in which the hydrocarbons prospection, exploration and production activities are allowed. The MED is expected to provide this map soon.

Another important piece of legislation expected to be adopted in the near future is the decree of the President of the Council of Ministers providing for the functioning of the newly established the Offshore Operations Safety Committee established by Legislative Decree 145/2015 implementing Directive 2013/30/EU on safety of offshore oil and gas operations.
Chapter 15  

MALAYSIA  

Fariz Abdul Aziz

I  INTRODUCTION

Commercial oil production in Malaysia began with the first commercial discovery made by the Royal Dutch Shell group in 1910 in Miri, Sarawak, half a century before Malaysia was formed. Today exploration and production activities are almost exclusively carried on offshore. The Oil & Gas Journal estimates Malaysia’s oil reserves to be the fourth largest in the Asia-Pacific region and one of the 30 largest reserves in the world. Malaysia has proven liquid reserves of roughly 2.26 billion barrels and liquids production of 664,000bp/d as of January 2016. According to Wood Mackenzie’s Malaysia Country Overview issued in July 2016, around 75 per cent of Malaysia’s commercial liquid reserves have now been produced and the majority of remaining liquids held within fields smaller than 100 million barrels in size although greenfield production from deepwater Sabah will result in production recovering to around 700,000bp/d in 2018 for the first time in 13 years.

The petroleum geology of offshore Malaysia is dominated by six sedimentary basins lying within a broad continental shelf. The Malay Basin and the Penyu Basin are located off the east coast of Peninsular Malaysia, while a number of sub-basins are held within the major Sabah and Sarawak hydrocarbon basins off the west coast of Borneo. Offshore north-east Borneo lie the two small basins of Sandakan and Taranak. The northern extension of the Taranak Basin lies in Malaysian waters.

In terms of gas production, the exploration arm of Malaysia’s national oil company, Petroleum National Berhad (PETRONAS), PETRONAS Carigali Sdn Bhd (PETRONAS Carigali) dominates the natural gas sector while Shell remains the largest foreign gas producer in Malaysia. Gas accounts for around two-thirds of Malaysia’s remaining commercial hydrocarbon reserve base, with an estimated total commercial remaining reserve of over 29tcf of gas. The Oil & Gas Journal estimates Malaysia’s gas reserves to be the third largest in the Asia-Pacific region after China and Indonesia. Over half of the country’s natural gas reserves

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Malaysia

are in its eastern areas, predominantly offshore Sarawak. Most of Malaysia’s gas reserves are associated with oil basins, although Sarawak and Sabah have an increasing amount of non-associated gas reserves that offset some of the declines from mature oil and gas basins offshore Peninsular Malaysia. Gas production in the Peninsula is supplied for domestic consumption while the majority of production in East Malaysia is converted to LNG for export.

The upstream sector is dominated by the national oil company PETRONAS, while the position of ExxonMobil and Shell illustrate the instrumental role the majors have played in the development of Malaysia’s upstream industry. Prior to 1998, only five companies operated Malaysian PSCs, with ExxonMobil, Shell and PETRONAS Carigali dominating acreage positions and production. In recent years however a trend has formed of awarding blocks to new entrants, with the likes of ENGIE, Salamander (acquired by Ophir Energy), Uzma, Octanex, Santos and Thailand’s PTTEP picking up blocks.

The 2016 licensing round opened in October 2015, with nine blocks offered; four offshore Peninsular Malaysia, three onshore Sarawak and two offshore Sabah. The blocks have failed to attract interest as investor appetite is currently low and the package consists of acreage offered in prior rounds. In May 2016, PETRONAS announced an additional seven blocks offshore Peninsular Malaysia and Sarawak, to be offered in mini-rounds over six months. According to Wood Mackenzie, the blocks located offshore Sarawak in the Central Luconia carbonate reef play should attract the most interest but potential entrants are looking for new acreage and improved fiscal terms, which may be offered in the 2017 licensing round.

II LEGAL AND REGULATORY FRAMEWORK

i Overview of the legal and regulatory framework

Domestic oil and gas legislation

While rights to hydrocarbon resources were originally within the purview of the respective state governments of the 13 states forming part of Malaysia, the 1973 global oil crisis drove home the need for the country to take more control over its hydrocarbon assets. In light thereof, the government of Malaysia decided to take over the ownership and rights of the state governments in respect of petroleum resources. For this purpose, the government incorporated Malaysia’s national oil company, PETRONAS as a public limited company and the Petroleum Development Act 1974 (PDA) was enacted and came into force on 1 October 1974. Pursuant to the PDA, the entire ownership in, and the exclusive rights, powers, liberties, privileges of exploring, winning and obtaining petroleum onshore and offshore Malaysia were vested in PETRONAS. The vesting of the ownership, rights, powers, liberties and privileges from the states to PETRONAS is in perpetuity and irrevocable. It took effect upon the execution of the vesting instrument by the ruler or the governor of the states.

The PDA and the Petroleum Regulation 1974 (Petroleum Regulation) enacted pursuant to the PDA represent the key legislative enactments that govern oil and gas exploration and production activities both onshore and offshore in Malaysia.

Apart from the vesting of the ownership in petroleum onshore and offshore Malaysia in PETRONAS, the PDA and Petroleum Regulations also set out the licensing requirements for the upstream activities as well as the downstream activities of refining, marketing and distributing oil products.
There are other laws and regulations that make up the general framework governing the oil and gas exploration and production industry in Malaysia. They include the Petroleum (Safety Measures) Act 1984 (PSMA) and the regulations made thereunder, which govern the transportation, storage and handling of oil and oil products, and the Environmental Quality Act 1974 (EQA), which is the main legislation governing the protection of the environment and the prevention of oil spills and pollutants on land and in Malaysian waters. As many of Malaysia's oilfields are situated in its exclusive economic zone, the Exclusive Economic Zone Act 1984 (EEZA), which governs activities in Malaysia's exclusive economic zone also plays a key part in regulating oil activities in Malaysia.

ii Regulations
As set forth above, the entire ownership in, and the exclusive rights, powers, liberties, privileges of exploring, winning and obtaining petroleum onshore and offshore Malaysia were vested in PETRONAS by virtue of the PDA. PETRONAS therefore exercises regulatory powers in respect of the upstream sector and therefore any person wishing to engage in exploration activities is required to be authorised to do so by PETRONAS either by entering into a production sharing contract with PETRONAS or by obtaining a licence from PETRONAS to provide services to the upstream industry.

The construction and operation of petroleum by pipelines is governed by the PSMA and the Petroleum (Safety Measures) (Transportation of Petroleum by Pipelines) Regulations 1985, which is under the purview of the Petroleum Safety Unit of the Ministry of Domestic Trade, Co-operatives and Consumerism.

Pursuant to a restructuring exercise in 2014, all functions relating to upstream regulation and governance relating to domestic oil and gas is exercised by a division within PETRONAS known as the Malaysia Petroleum Management.

iii Treaties
Malaysia's bilateral investment treaties (BITs)
Malaysia signed its first BIT with Germany on 22 December 1960. Over the past 54 years it has signed at least 71 BITs, of which at least 53 have entered into force. At least 39 of these BITs are publicly available at the time of writing.

The vast majority of publicly available BITs signed by Malaysia provide that a dispute arising between a contracting state and an investor shall as far as possible be resolved amicably. If this is not possible through negotiations and consultations, or through the pursuit of local

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2 Based on information available on the United Nations Convention on Trade and Development website, Malaysia has signed BITs with Albania, Algeria, Argentina, Austria, Bahrain, Bangladesh, Belgium and Luxemburg, Bosnia and Herzegovina, Botswana, Burkina Faso, Cambodia, Chile, China, Croatia, Cuba, the Czech Republic, Denmark, Djibouti, Egypt, Ethiopia, Finland, France, Germany, Ghana, Guinea, Hungary, India, Indonesia, Iran, Italy, Jordan, Kazakhstan, the Republic of Korea, the Democratic People's Republic of Korea, Kuwait, Kyrgyzstan, Laos, Lebanon, Macedonia, Malawi, Mongolia, Morocco, Namibia, the Netherlands, Norway, Pakistan, Papua New Guinea, Peru, Poland, Romania, Saudi Arabia, Senegal, Spain, Sri Lanka, Sudan, Sweden, Switzerland, Syria, Taiwan, Turkey, Turkmenistan, the United Arab Emirates, the United Kingdom, Uruguay, Uzbekistan, Vietnam, Yemen and Zimbabwe.
remedies as stipulated in the Malaysia–Finland BIT, after a specified period (generally three or six months), the dispute shall be submitted to arbitration or to the courts or tribunals of the contracting state.

**ICSID**
Malaysia is a party to the Convention on the Settlement of Investment Disputes Between States and Nationals of Other States (ICSID Convention), also called the Washington Convention of 1966, which established the International Centre for Settlement of Investment Disputes (ICSID). ICSID’s primary purpose is to provide facilities for conciliation and arbitration of international investment disputes and to provide signatory states and their investors with a self-contained framework for the recognition and enforcement of the awards resulting out of ICSID proceedings. Malaysia signed the ICSID Convention on 22 October 1965 and deposited its ratification on 8 August 1966. The ICSID Convention entered into force in Malaysia on 14 October 1966.

**The New York Convention**
The Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention) seeks to provide common legislative standards for the recognition of arbitration agreements and court recognition and enforcement of foreign and non-domestic arbitral awards. It obliges parties to ensure that foreign and non-domestic arbitral awards will not be discriminated against but will be recognised and enforced in the same way as domestic awards in each of the signatory states. While ICSID awards benefit from the specific enforcement framework offered under the Washington Convention, the New York Convention plays a very important role in the enforcement of these other arbitral awards. Malaysia has been a contracting state to the New York Convention since 3 February 1986.

**Double taxation agreements**
As at the date of writing, Malaysia has entered into more than 70 bilateral double taxation agreements. Generally under the double taxation agreements, income such as business profits, dividends, interests and royalties derived from Malaysia by non-residents are not subject to Malaysian income tax unless the non-resident carries on activities within Malaysia through a permanent establishment, that is, a fixed place in Malaysia where a trade or business is carried on.

###III LICENSING

####i Production sharing contracts
Since the enactment of the PDA and prior to the instruction of the risk service contract (RSC) framework, a company seeking to obtain rights to explore, develop and produce petroleum is required to enter into a production sharing contract (PSC) with PETRONAS. Almost all licences in Malaysia presently are governed by PSCs, of which there are four main types:

- **1976 PSC model**;
- **post-1985 PSC model (conventional areas)**;

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post-1985 PSC model (deepwater areas); and
post-1996 PSC model (revenue/cost index).

Deepwater blocks are defined as those in water depths of greater than 200 metres.

The terms and scope of the rights granted are entirely contained in the PSC and such rights are enforceable under Malaysian law. The terms of the PSC provide that the parties to the PSC (referred to as PSC contractors) shall be solely responsible for the provision of all funds required directly or indirectly for petroleum operations. PSC contractors are then entitled to recover costs related to petroleum operations and a share of profits from the production of crude oil or natural gas in kind based on a defined formula contained in the PSC.

As a matter of policy, PETRONAS’ exploration and production arm, PETRONAS Carigali, must be a party to all PSCs awarded by PETRONAS with a view to allowing the state a direct interest in the PSC awarded as well as the ability to derive knowledge from the other PSC contractors, which are (mostly) foreign international oil companies. Under current PSC terms, PETRONAS Carigali has the right to a carried interest in any exploration block during the exploration period. The interest is negotiable, but it usually varies between 15 and 25 per cent. Once a commercial discovery has been made, PETRONAS Carigali must elect whether or not to become a working partner in any development.

The PDA expressly stipulates that in return for the vesting of ownership and rights in the petroleum resources, PETRONAS is to make cash payments to the federal government and the relevant state governments (where petroleum is produced). The payments are made by PETRONAS in the form of royalty payments to the federal government, which are in turn distributed to the relevant state governments. The source of these payments is the production of oil and gas under the various PSCs and RSCs. Under the PSC and RSC framework, 10 per cent of all petroleum won and saved by PSC contractors is paid to PETRONAS in order to satisfy payment of royalties under the PDA.

Apart from the royalty payments, PSC contractors are also required to share a certain proportion of profit oil or profit gas from crude oil and natural gas produced with PETRONAS based on a predetermined formula. In order to share in any upside in the price of oil PSC contractors are required to make supplemental cash payments to PETRONAS for such portion of the PSC contractor’s portion of the profit oil or profit gas that exceeds the specified base price agreed in the PSC.

**ii Risk service contracts**

In early 2011 and as a result of feedback from industry players, PETRONAS introduced the award of RSCs. These contracts were introduced to unlock the value of marginal fields that are technically challenging and capital intensive. Under the terms of the RSC, PETRONAS will retain resource ownership, while the RSC contractors will hold responsibility for field development and operation. While PETRONAS has yet to introduce a model RSC, the terms of each of the RSCs introduced so far generally provide for cost recovery of all capital and operational expenditure upon commencement of production as well as a remuneration fee based on certain predetermined performance indicators. A key feature of the RSC framework is its flexibility in dealing with the economics of diverse types of situations from RSCs for development of a cluster of fields to RSCs that have the sole purpose of accelerating the development of oil fields to production by leveraging existing infrastructure.
To date a total of six RSCs have been awarded by PETRONAS. With the break-even cost of these RSC developments believed to be as high as US$60 per barrel, the economics of these contracts have been called into question. The low oil price environment has already led to two RSCs being terminated early and PETRONAS has announced that it would not be awarding any more new RSCs as long as oil prices remain below US$80 per barrel.

iii Licence to provide services to the upstream industry

Pursuant to the Petroleum Regulations, a company must be licensed by PETRONAS before it can supply goods and services to the upstream oil and gas industry in Malaysia. Pursuant to the Licensing and Registration Guidelines issued by PETRONAS (the PETRONAS Guidelines), in order for foreign companies to take part in tenders or to carry on business in both upstream oil and gas industry in Malaysia, such companies shall either: appoint a local company that is duly licensed by PETRONAS as an exclusive agent to represent it in Malaysia; or enter into a joint venture with a Malaysian company or an individual typically through holding shares in a newly incorporated joint venture company that will then need to obtain a PETRONAS licence.

IV PRODUCTION RESTRICTIONS

Since the discontinuation of the National Depletion Policy that previously limited production of crude oil to an average 630,000bpd as well as capping the consumption of gas in Peninsular Malaysia to about 32,000 million standard cubic feet per day, Malaysia no longer imposes any production limitations as a matter of policy. However, PETRONAS nevertheless reserves the right to restrict PSC contractors from holding Malaysian crude oil in any form of buffer stock that is contrary to contractors’ normal market operations.

i Export of oil and gas produced

In respect of the export of crude oil, PSC contractors are free to lift, sell and export their respective entitlements of crude oil produced subject to obtaining the relevant customs approvals and reporting obligations to PETRONAS. In terms of gas sales, PSC contractors are required to sell their entitlement of natural gas produced on a joint dedicated basis with PETRONAS.

ii Requirements for sales of production into the local markets

While there are generally no requirements for PSC contractors to sell any portion of oil produced to the local market, this is subject to provisions contained in the PSC that apply to times of general shortage of supplies of petroleum in countries that are from time to time members of the ASEAN Council on Petroleum (ASCOPE) or its successor, or to Malaysian refineries and petrochemical plants. In such times, PSC contractors are required to give preference to prospective buyers in such countries and to Malaysian refineries and petrochemical plants provided that the prices and other terms of purchase offered are competitive.

V ASSIGNMENTS OF INTERESTS

As the right and interest relating to the exploration, production and development of oil and natural gas in Malaysia is derived by PSC contractors from the PSC, the applicable
restrictions are governed under the contractual terms of the respective PSCs rather than by legislative enactments. The Malaysian PSC generally provides a restriction on any assignment of a participating interest of a PSC contractor in the PSC unless the prior written approval of PETRONAS (through the Malaysian Petroleum Management Department) is obtained.

An assignment of interest, whether directly or indirectly will also be subject to the consent and pre-emption rights provided for under the joint operating agreement to each PSC contractor. In addition, depending on what stage of exploration or production the PSC is in, parties undertaking an assignment of interest may also need to resolve issues relating to the ancillary agreements such as petroleum handling arrangements and infrastructure sharing agreements as part of the transfer process, particularly if the transfer involves a change in operatorship in the relevant PSC.

From a timing perspective, the approval and pre-emption process will generally take three to four months in respect of a routine transfer of interest.

VI TAX

i Petroleum (Income Tax) Act 1967

The Petroleum (Income Tax) Act 1967 (PITA) governs the taxation of petroleum income in Malaysia. PITA came into force in 1967 and was initially designed for concession agreements between the international oil companies and the state governments. Over the years, it has been amended to accommodate the PSC regime.

Petroleum income tax is charged on the income of every ‘chargeable person’ derived from ‘petroleum operations’ in Malaysia at the rate of 38 per cent. The ‘chargeable persons’ under PITA are PETRONAS, the Malaysia–Thailand Joint Authority and PSC contractors in respect of each PSC. PSC Contractors are taxed on a per-PSC basis on the profit oil and profit gas (less allowable deductions and capital allowances) produced from its operations in Malaysia. PITA allows qualifying exploration expenditure and all outgoings and expenses wholly and exclusively incurred in the production of gross income to be deducted from the gross income. Each PSC is considered as a separate chargeable person. Where a PSC partnership (e.g., parties to a PSC through a JOA or a shareholding in a company) is party to more than one PSC partnership, its ‘cost pools’ from one PSC partnership cannot be used against revenues from another PSC unless the PSC areas are geographically contiguous.

Malaysia is defined as the territories of the Federation of Malaysia, the territorial waters of Malaysia, its exclusive economic zones and the seabed and subsoil of such areas. PETRONAS is also taxed under PITA for the sale within Malaysia of any petroleum obtained outside Malaysia. Income derived from services provided to upstream operations is not taxed under PITA but under the Income Tax Act 1967 (ITA). Income derived from downstream operations is also taxed under ITA.

ii Tax incentives

To encourage the development of marginal oil fields, marginal fields, enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature and deepwater projects, the government introduced new tax incentives through subsidiary legislations. They are as follows:

a Petroleum (Income Tax) (Exemption) Order 2013 (Exemption Order);
b Petroleum (Income Tax) (Accelerated Capital Allowances)(Marginal Field) Rules 2013 (ACA Rules);
They are collectively known as the New Tax Incentives.

The New Tax Incentives took effect in November 2010. The ACA Rules allows for accelerated capital allowance (ACA) on qualifying plant expenditure incurred for petroleum operations in a marginal field. Applying the ACA rate, capital allowance on qualifying plant expenditure can be fully claimed within five years as opposed to 10 years based on conventional capital allowance rates. Under the Exemption Order, the Minister exempts a portion of the statutory income derived from petroleum operations in a marginal field, which results in chargeable income derived from marginal fields being taxed at 24.966 per cent instead of 38 per cent.

The IA Regulations provide for an investment allowance equal to 60 per cent of qualifying capital expenditure incurred in that basis period for a year of assessment within a period of 10 years in respect of a qualifying project; or on an infrastructure asset as determined by the Minister. A ‘qualifying project’ is a project in a field that carries out either enhanced oil recovery, high carbon dioxide gas, high-pressure, high-temperature or any combination thereof; or in an area under a PSC in respect of a deepwater project. It results in a 60 per cent investment allowance in addition to capital allowance and 70 per cent statutory income from a qualifying project is tax exempted equal to the investment allowance available.

**Goods and services tax**

Goods and services purchased or supplied for upstream operations are subject to a goods and services tax (GST) under the Goods and Services Tax Act 2014 (GST Act), which came into force on 1 April 2015. Acquisition of materials, equipment and services for petroleum operations is considered as input to the upstream contractor. Any GST incurred by the operator under a PSC in purchasing the input is claimable as input tax credit which can be offset against GST charged on the supply of a product. As a general rule, all types of taxable supply pertaining to upstream activities are subject to GST at the standard rate of 6 per cent if they are supplied in Malaysia, except for the exportation of crude oil, condensate and gas which is subject to GST at a zero rate.

The Royal Malaysian Customs has issued guidelines providing that a transfer of participating interest in a PSC between existing venturers or to a new venture will be considered as a taxable supply under the GST Act and, if there is a consideration involved, will be subject to GST at a standard rate.

**VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING**

Decommissioning of oil and gas facilities and pipelines is governed by a number of laws due to the variety of activities that are required to undertake abandonment and decommissioning. Such laws include the Continental Shelf Act 1966, the Exclusive Economic Zone Act 1984, the Petroleum (Safety Measures) Act 1984, the Environmental Quality Act 1974, the Occupational Safety and Health Act 1994, the Fisheries Act 1985, the Merchant Shipping Ordinance 1952 and the Merchant Shipping (Oil Pollution) Act 1994. In summary, the laws require that the abandonment and decommissioning activities are carried out safely, do not cause any environmental degradation and do not interfere with other offshore activities such as fishing. Specific responsibilities for abandonment are also set out in the PSC.
The terms of the PSC require that PSC contractors make payments to a fund for abandonment and decommissioning operations known as the ‘abandonment cess’. Payment of the abandonment cess commences upon commercial production of petroleum and is payable on an annual basis. Such payments are cost recoverable under the terms of the PSC.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
The form of entity permitted to carry out exploration and production activities in Malaysia depends on the nature of activities undertaken. In respect of entry into a PSC or RSC, the party who will be the operator is required by law to either be a company incorporated in Malaysia or a foreign company that has established a branch in Malaysia. Non-operator parties on the other hand are not strictly required to maintain a Malaysian branch although they may be required to do so by PETRONAS.

Companies who intend to engage in the provision of services in Malaysia on the other hand are either required to do so through a Malaysian-incorporated joint venture company with Malaysian participation or must appoint a Malaysian-incorporated company as an agent to provide services. Specific equity requirements apply to such locally incorporated entities depending on the type of services provided.

Timing wise, the establishment of locally incorporated companies or the registration of a local branch generally takes two to three weeks.

ii Capital, labour and content restrictions
Non-residents are free to invest in Malaysia in any form. There is no restriction on the repatriation of capital, profits and income earned from Malaysia, including salaries, wages, royalties, commissions, dividends, interest, fees or rent arising from investments in Malaysia. Ringgit assets purchased by residents from non-residents may be settled in ringgit or foreign currency, other than the restricted currency (New Israeli shekels). However, all remittances abroad must be made in foreign currency other than restricted currency.

PSC contractors and RSC contractors are required to comply with the national objective of maximising Malaysian participation in the use of local equipment, facilities, goods, materials, supplies and services required for petroleum operations. In pursuance of the foregoing, PSC and RSC contractors are required to enhance effective local participation in equity, management and employment.

As part of the Malaysianisation policy established by PETRONAS in 1976, PSC and RSC contractors are required to undertake a Malaysianisation process, which includes committing to Malaysianisation targets for senior management, critical disciplines and overall employment of Malaysians. In light of this, maximum limits are imposed on the number of foreign employees that may be engaged.

iii Anti-corruption
The primary body of law on anti-corruption is the Malaysian Anti-Corruption Commission Act 2009 (the MACC Act) which came into effect on 1 January 2009. The MACC Act is the successor to the Anti-Corruption Act 1997 and is designed to bring Malaysia’s anti-corruption framework in line with its international obligations under the United Nations Convention Against Corruption.
It is a crime for a person to offer to any officer of any public body any gratification as an inducement or a reward for the officer to vote or refrain from voting with respect to any public body decision making, to perform or abstain from performing any official act, to assist in procuring or preventing the granting of any contract for the benefit of any person or to show any favour or disfavour in his official capacity, notwithstanding that the officer did not have the power, right or opportunity to perform or accepted the gratification without intending to perform.

It is also a crime for an officer of any public body to solicit or accept any gratification as an inducement or reward to perform any of the aforementioned.

Domestic public officials generally include members, officers, employees and servants of a public body, such as the administration, the parliament, the state legislative assembly, the federal courts, other parts of the federal government, the state government, local authorities, government majority-owned corporations, registered societies and trade unions, and persons who receive remuneration from public funds. In light of the generality of this definition, employees of PETRONAS are generally regarded as public officials although such position has yet to be determined definitively by the Malaysian courts.

IX CURRENT DEVELOPMENTS

Malaysia has not been spared the consequence of the dramatic decline in oil prices at the end of 2014 and beginning of 2015. The most prominent effect was the announcement by PETRONAS that it would be looking to target a reduction in its capital expenditure by at least 15 per cent and operational expenditure by 20 per cent. In connection thereto, PETRONAS has introduced and leads the Cost Reduction Alliance (better known as CORAL 2.0), an industry-wide initiative involving 25 PSC Contractors with the stated aim of inculcating a ‘cost-conscious mindset that will ultimately embrace a structural change in Malaysia’s upstream business environment, to benchmark efficiency with best-in-class performance and to increase collaboration and innovation as well as infuse global best practices’. CORAL 2.0 is PETRONAS’ second such initiative following on from CORAL 1.0 set up in the 1990s, which was successful in achieving aggressive cost reductions of up to 30 per cent.

The dramatic decline in oil prices beginning in late 2014 has forced PETRONAS to review its investment plans. Frontier exploration and appraisal campaigns as well as large-scale enhanced oil recovery projects have stalled as companies cut discretionary expenditure to a minimum in anticipation of a market recovery in the future. Notably, PETRONAS is committed to bringing its FLNG 1 project offshore Sarawak online by the end of 2016. However, the FLNG 2 development to be moored offshore Sabah has been delayed by two years with a revised start-up date of 2021. The current oil prices have also made RSC developments, which typically require a breakeven of greater than US$60/bbl, uneconomical. In 2016, two RSC contracts – the Balai Cluster and the Berantai RSCs – were terminated with operatorship transferred to PETRONAS’ subsidiary Vestigo Petroleum.
Chapter 16

MEXICO

Carlos Ramos Miranda and Miguel Ángel Mateo Simón

I INTRODUCTION

i General overview

The Mexican upstream (and most of the downstream) oil and gas sector is controlled by the Mexican state. Under the Mexican Constitution (the Constitution), all hydrocarbons in the subsoil, whether in solid, liquid or gaseous state, belong to the Mexican nation. However, based on a constitutional reform enacted published on 20 December 2013, the state has ceased to have the monopoly over the hydrocarbon industry, though it has retained for itself the monopoly on the exploration and exploitation of hydrocarbons. However, exploration and exploitation activities may be carried out through contracts with state-owned entities or with the private sector. In this context, hydrocarbon reserves are owned by Mexico, but contractors (whether state-owned productive companies or private parties), will be able to report the contracts they secure, and the expected benefits stemming therefrom. As a consequence of the constitutional reform, implementing legislation was issued in August 2014.

Private parties may now participate in the upstream sector through licences, production sharing contracts, profit sharing contracts or services contracts with the Mexican state. Each type of contract shall have its own commercial and fiscal terms. No concessions will be granted for exploration and exploitation activities. The state will be able to continue to engage in exploration and exploitation activities through state-owned production companies, which will be able to enter into contracts with the state, or receive allocations (which are similar to concessions, except that they are only granted to state-owned production companies).

Contracts are to be granted by the Ministry of Energy (MoE), through the National Hydrocarbon Commission (NHC). The MoE will act as a policymaker, while the NHC will act as regulator and implementer of the said energy policies set by MoE. The Ministry of Finance will determine the fiscal terms of the contracts to be granted.

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As in the case of the Mexican investors, foreign investment is allowed in the upstream sector. Restrictions on foreign investment participation in the sector were eliminated as part of the implementing legislation issued in August 2014.

ii  Production and reserves
Mexico has a crude oil production of 2.3 million barrels of oil per day, and 8.6 million cubic feet of natural gas per day. Currently, proven reserves of Mexico are 7.9 million barrels. The reserve-to-production ratio is 8.1 years for proven reserves.\(^2\) The energy reform is expected to result in a significant increase of both reserves and production.

iii  Policy
Mexico’s oil policy since 1936 had been embedded in a nationalistic sentiment whereby the state ownership of the oil reserves is considered synonymous with national sovereignty. The constitutional reform of late 2013 and the implementing of secondary legislation that ensued have almost immediately converted Mexico into an important player and attractor of international oil companies and overall service companies in the sector.

Mexico’s specific oil and gas policy activity for the future years will continue to be designed, planned and in most instances implemented by the MoE and the Ministry of Finance (they both actively participate in the pricing of crude oil for international markets and in hedging transactions), although part of the implementing of the reform will include the contracting of third parties to commercialise the crude oil. Regulatory agencies such as the NHC depend directly on the MoE and thus, although they have operational independence, they are strictly linked to the MoE, which is different from practice in other countries.

The Mexican policy instruments regarding oil and gas are contained in the National Development Plan and the National Energy Strategy. These documents are drafted by the Executive. As for oil and gas, both documents are consistent in that the driver of the overall energy policy is the security of supply and the enhancement of exploration and production activities. The intention is to set up a framework that allows Mexico to increase its hydrocarbon reserves while increasing oil and gas output. The natural gas component is especially important, since Mexico is currently facing significant issues (including pricing issues) with its supply of natural gas. These issues are created by Mexico’s limited downstream transport, processing and storage capacity, which is also expected to increase based on structural changes to the manner in which the downstream sector operates.

iv  Major developments and current issues
In spite of an amendment to the general framework governing the oil and gas sector in 2008, the energy sector required a substantial transformation. This transformation finally took place at the end of 2013, and was implemented in 2014, and required impressive political negotiation by the executive. The changes include the clear separation of authority between the MoE, NHC and the Ministry of Finance, and the creation of a stronger corporate framework for state-owned productive companies, such as Petróleos Mexicanos and its subsidiaries (Pemex). Most important is the drastic change to allow private participation in exploration and exploitation activities.

\(^2\) http://www.pemex.com/rt/finanzas/Resultados%20anuales/151231_Estfin_e.pdf.
As part of the energy reform, Pemex was required to request the maintenance of specific allocations (also known as ‘round zero’) from the MoE, and now has the ability to convert those confirmed into host government contracts (whether licences, production or profit sharing, or services contracts). In such migration, Pemex will be allowed to venture with private parties through joint operating agreements. In these instances, the specific private party with which Pemex may venture will be elected through a bidding process conducted by the NHC. The bidding terms are still unknown. However, with respect to those areas in which Pemex has allocation where a private party is currently providing services for Pemex, such suppliers may agree to partner with Pemex in such migration process without a need of a public tender. These will be the first allocations to be migrated into host government contracts.

As an important aspect of the reform is the change to the existing fiscal regime applicable to Pemex in order to reduce the federal government’s dependence on the oil revenue and allow for effective competition in the industry (in midstream and downstream activities as well).

By mid-2016, over 25 exploration and extraction contracts have been awarded to a wide array of contractors, ranging from international to national oil companies. Currently, the last bid under Round 1 is in progress, which will result in the granting of deep water exploration and extraction contracts. Further, the first Pemex migration is underway, through a bid to award a contract to joint venture with Pemex in a deep water area known as Trion. The results of these two bids will be issued in December 2016.

In addition, all of the agencies involved in the regulation of hydrocarbon activities have issued and continue to issue different regulations and standards with respect to the processing of hydrocarbons, midstream activities, environmental and safety requirements, and insurance guidelines for the industry as a whole.

II LEGAL AND REGULATORY FRAMEWORK

Upstream oil and gas activities are regulated mainly by laws issued by the Mexican Congress and Regulations and Guidelines issued by the executive branch, or by regulatory bodies such as the NHC, MoE, the Ministry of Finance and the Ministry of Environment. Oil and gas comes under federal jurisdiction, and as such, states cannot legislate on or regulate activities regarding the sector.

i Domestic oil and gas legislation

\textit{Mexican Constitution (specifically, Articles 25, 27 and 28)}

The Constitution includes the mineral and hydrocarbons state ownership regime. It specifies that title to all hydrocarbons within the Mexican territory is owned by the Mexican state, and no concessions will be granted. However, it allows the state to grant host government contracts for contractors to perform exploration and exploitation activities on behalf of the state. Further, Article 28 of the Constitution grants the monopoly of the exploration and exploitation activities to the Mexican state.

\textit{The Hydrocarbons Law (HL)}

This law regulates the oil and gas (upstream, midstream and downstream) industry as a whole and establishes the main principles of the sector. While the exploration and exploitation
activities are reserved to the state, the Hydrocarbons Law regulates host government contracts and the overall structure of the industry (not only upstream but also midstream and downstream).

**The Hydrocarbon Income Law (HIL)**
The HIL regulates the tax aspects of the upstream industry in Mexico. It contains the basis for the determination of the fiscal terms of the host government contracts, and specific income tax principles to be applied to contractors. It also establishes a zero per cent value added tax to these activities, which is an important incentive and cost-saving mechanism for the industry. The HIL also regulates the tax regime applicable to state-owned production companies that continue to work in exploration and exploitation activities under allocations.

**The Pemex Law**
The Pemex Law sets the corporate governance principles and framework under which Pemex and its subsidiaries will operate and specifies the general basis under which Pemex will contract private contractors, along with the manner in which the compensation to said private contractors will be designed. Notably, this law provides that Pemex will be a state production company, and as such, will not be subject to many of the burdensome administrative laws that have traditionally restricted Pemex's ability to conduct its operations in an efficient manner. The most dramatic change is a change in the mindset of Pemex itself since, in spite of being a state-owned production company and the advantage of round zero, Pemex will now be a competitor with other international oil companies in Mexico.

**Law of the NHC (LNHC)**
The LNHC sets out the framework under which the NHC will operate, including its functions, purpose, organisation and authority as a technical regulator of the industry, including its new role of organising the bidding rounds and acting as a supervisory body with respect to compliance with the contracts.

**Law on the Mexican Petroleum Fund for Stability and Development (the Mexican Petroleum Fund Law)**
This law sets up the Mexican Petroleum Fund for Stability and Development as a trust, which will receive, manage, invest and distribute the income stemming from allocations and host government contracts (except for taxes). The fund is to be managed by the Central Bank of Mexico. The fund will serve as a mechanism to receive income from the proceeds of sale of hydrocarbons, and compensation to the state or contractors under the host government contracts. The fund will also serve to create several additional funds for the stabilisation of income for the federation, the states and other funds aimed at fostering research and development.

**Law on the National Agency of Industrial Security and Protection to the Environment of the Hydrocarbon Sector (the HS&E Agency Law)**
This law creates the Agency for the Industrial Safety and Protection of the Environment of the Hydrocarbon Sector (the Agency). The Agency is a part of the Ministry of the Environment and Natural Resources, and is entrusted with issuing regulations on industrial safety and environmental protection in the sector, and supervising compliance with such regulations and guidelines.
The Regulatory Bodies Law
The Regulatory Bodies Law regulates the Energy Regulatory Commission, which mainly supervises downstream activities and power, and the NHC, which regulates and supervises exploration and extraction activities, including collection of hydrocarbons up until they are transported and stored. The NHC is also entrusted with conducting the bidding processes for the granting of host government contracts and the management of said contracts.

The Regulatory Bodies Law also sets forth the rules of engagement for the purposes of transparency and fairness. Therefore, special rules apply with respect to a code of conduct. These entities are also entrusted with sufficient independence to properly regulate the sector, and its resolutions may only be challenged through amparo proceedings (constitutional suit).

ii Regulation
The regulator of the upstream oil and gas sector is the NHC, which although independent from a technical and operational standpoint, will have to make sure it pursues the policies set by the MoE. The NHC is responsible for ensuring that exploration and extraction projects are performed pursuant to the following conditions:

a. to increase the recovery and maximum volume of oil and gas in the long term, in commercial conditions, over reservoirs, wells, abandoned fields, fields in the process of being abandoned or in their exploitation phase;

b. to reserve restitution, to guarantee energy security;
c. to use the most adequate technology for the exploration and extraction of hydrocarbons, to obtain economic and productive results;

e. to perform the exploration and extraction of hydrocarbons under adequate industrial safety conditions; and

f. to reduce natural gas flaring and venting to a minimum.

iii Treaties
Mexico is part of the following conventions (not an exhaustive list) that have a relationship with exploration and production activities:


d. North America Free Trade Agreement;

e. EU–Mexico Free Trade Agreement;
f. Japan–Mexico Free Trade Agreement;
g. US–Mexico Transboundary Hydrocarbons Agreement;

h. double taxation treaties with Belgium, Canada, Denmark, Finland, France, Germany, Iceland, Italy, Norway, Russia, Singapore, Spain, Sweden, Switzerland, the United Kingdom and the United States, among others; and

i. the Hague Convention for the Abolishment of the Requirement of Legalisation for Foreign Public Documents.

III LICENSING
Constitutionally, title to oil and gas and the right to explore and exploit hydrocarbons belongs to the Mexican state and cannot be transferred to private parties. The Mexican state exercises
such rights through contracts or allocations to state production companies or contracts with private parties. Although contracts with private parties do include licences, these are not to be understood as concessions, but rather as contracts whereby the private party is compensated with a portion of the production. Thus, there is no entitlement to the hydrocarbon upon production, but upon compensation actually being paid.

Under licences, the contractors are obliged to pay the state (through the Mexican Petroleum Fund) a signing bonus and a contractual fee (based on a fixed fee per square kilometre of the contractual area during the exploration phase). The state also has the right to receive a royalty based on a progressive formula, and compensation for the hydrocarbons produced based on a percentage of the contractual value of the production. The contractor will then be entitled to receive, and compensation the remaining hydrocarbons produced.

Under production and profit sharing contracts, the contractors are obliged to pay the state (through the Mexican Petroleum Fund) a contractual fee; the state is also entitled to receive a royalty based on a percentage of the value of the hydrocarbons, and compensation based on a percentage of the operating profit. The contractor will then be entitled to cost recovery up to a percentage of the costs, and compensation based on the remaining percentage of the operating profit. In the case of production sharing contracts, the contractor will be paid in kind with the hydrocarbons produced.

In all bid processes to award these contracts, the state may require mandatory state participation in those cases where the contract area overlaps with technology and knowledge transfer, and the use of a specialised financing entity of the state. Also, where a trans-boundary field is found, the Mexican state is to participate with a share of no less than 20 per cent in the project.

The first production sharing contracts were awarded in July 2015.

IV PRODUCTION RESTRICTIONS

Upon being granted an allocation to explore and produce, Pemex has no restrictions as to the quantity of oil that can be produced in a particular field. The same applies in the case of contracts for exploration and extraction. However, the NHC has the authority to approve the exploration and extraction plans to ensure maximum productivity of the contract area in a sustainable fashion. Of course, all production activities will need to be undertaken in accordance with all technical and environmental guidelines.

V ASSIGNMENTS OF INTERESTS

Interests under the agreements cannot be assigned totally or partially without the prior authorisation of the NHC. The law also provides that change of corporate control, or control of the operations (i.e., changing operator) also requires the prior consent of the NHC. Failure to abide by this rule will render the assignment null and void. The restrictions imposed under the HIL will make it difficult for contractors to easily farm out, or to conduct exclusive operations.
VI TAX

Mexico taxes rights or fees depending on the type of contract or allocation. The HIL provides for specific fees to be paid based on the type of oil and field. In the case of contracts, in addition to the contractual fees agreed to under the contract (i.e., contractual fees, royalties and a percentage of the operational profit), contractors and state-owned production companies are subject to income tax. The compensations under the contracts will be designed in such a fashion as to allow the state to collect windfall profits. Also, special rules on deductions will apply to allow for the accelerated depreciation of certain investments. The HIL also states that specific activities for which compensation under the contracts arises shall be subject to zero per cent value added tax.

It is important that there is no tax ring-fencing in the case of contracts and thus, contractors holding more than one contract will be able to consolidate all such exploration and extraction costs, expenses and income.

In the case of joint operations, the HIL provides for an efficient, yet inflexible tax regime for the operator and non-operators.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

i Environmental impact

As part of the Energy Bill, the HS&E Agency Law was issued. The purpose of the law is the creation of an Agency that is part of the Federal Environmental Ministry and will be a dedicated regulator of the hydrocarbon industry. The main objective of the Agency is to protect people, the environment and the facilities of the hydrocarbon sector by regulating and supervising the following:

a the industrial and operative safety of the various players in the industry;
b the dismantling and abandonment of facilities; and
c the waste and polluting emissions.

The EH&S Agency is entrusted with the following responsibilities:

a to create the regulation for the hydrocarbon sector in the areas of industrial and operative safety, and environmental protection, in relation to the facilities and activities of this sector, including decommissioning and abandonment of facilities;
b to supervise compliance with general rules and Mexican Official Standards;
c to conduct inspection and verification visits;
d to determine sanctions and safety measures;
e to provide the basis for projects and other activities of the hydrocarbon sector, so that they are performed in accordance with the industrial safety and environmental protection standards;
f to investigate the cause of accidents and disasters in the hydrocarbon sector;
g to issue, suspend, revoke or deny the licences, permits, authorisations and registrations in environmental matters. Among these environmental matters are the following:

• environmental impact of the hydrocarbon sector;
• environmental risk of the hydrocarbon sector;
• emission of odours, gases or solid or liquid particles to the atmosphere;
• hazardous waste;
- remediation of contaminated sites; and
- change of soil use in forest land.

Companies operating in the hydrocarbon sector must have an area in charge of the implementation, assessment and improvement of a management system (the system) established by the Agency.

The purpose of the system is to prevent, control and improve the industrial and operative safety, and to protect the environment. The system shall at least include the following:

- risk identification and assessment;
- preventive measures, monitoring, mitigation and assessment of incidents, accidents and affectations;
- goals, targets and performance indicators;
- general training plan;
- procedures for incidents and accidents registration, investigation and analysis;
- internal and external legal aspects of the activities of the entities regulated by the law; and
- a periodical performance report.

The Agency may take several safety measures in order to respond to critical risks (i.e., risks that pose imminent danger and require immediate action to mitigate), including the suspension of the construction of works and facilities, suspension of supply services, securing of assets, and debarment of the use of specific substances, materials, equipment or accessories.

The Agency is empowered to impose sanctions for the acts or omissions including fines that could amount to several million US dollars.

ii Decommissioning

The HL provides that the Agency is to issue a regulation with respect to financial mechanisms to be adopted by state-owned production companies and contractors in order to ensure that sufficient funds are designated to the decommissioning of facilities and abandonment of land that has been occupied, used or affected by the contractor activities. These activities shall include not only activities mandatory under law, but also those agreed with the corresponding landowners. In all cases, the activities need to be undertaken under best practices.

Further, regulation to be issued by the Agency shall include the manner in which the above-mentioned financial mechanisms will also ensure funds are available to cover damage caused.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

An investor can choose any type of Mexican corporate vehicle to carry out oil and gas activities in Mexico. The most common structure used to operate in Mexico is through a Mexican stock corporation (SA) or through a limited liability company (SRL). While there is no different tax treatment for these types of entities in Mexico, the main difference of these types of companies is that the SRL is a closed-type corporate entity and does not allow for the transfer of interests or the admission of new partners as easily as the stock corporation. However, for US tax purposes, SRLs can be classified as tax-transparent entities.
Mexico

for the purposes of US tax law. In addition to the above, both entities are limited liability entities, and thus partners’ or shareholders’ liability is capped to their investment (with a few exceptions). Mexico’s proposed tax bill for 2014 may render such tax benefits ineffective.

An SA can also be formed as an investment promotion stock corporation (SAPI). A SAPI is a stock corporation and will operate under the same rules as a regular SA, although it is vested with additional rules that allow for more flexibility with regard to specific shareholder arrangements that may be questionable under a normal SA.

To establish a local entity, at least two shareholders or partners are required. The parties will need to secure an authorisation to use the corporate name and draft a set of by-laws. The by-laws will need to include, *inter alia*, the corporate name, corporate domicile, term, corporate governance structure, etc. Once the former requirements have been obtained, the by-laws will need to be formalised by a notary public or commercial law notary public. The process takes about 10 business days. Once the public deed has been issued, the same will need to be registered with the Public Registry of Commerce, and in case of foreign investment participation in the company, then registration with the Foreign Investment Commission is required. Finally, the local company will need to be registered with the Mexican Tax Administration Service.

Foreign investors may operate through a branch; however, there are two main practicalities to consider: the branch will be considered a permanent establishment for tax purposes with respect to the income-generating activities it performs in Mexico; and the liability of the branch in Mexico will be the same liability as of the ‘home office’; that is, if the branch is liable in Mexico the creditor may collect against the assets of the branch’s home office in the home country, as under Mexican law, the branch is the same entity as the home office. Further, the HL does require contractors to be incorporated in Mexico (although no restriction as to the nationality of the capital exists). Consequently, investors who wish to be considered as contractors under a host government contract must be incorporated in Mexico.

Notably, the energy bill also eliminated a restriction for foreign investment to participate in companies whose main activity is the drilling of oil or gas wells.

**ii Capital, labour and content restrictions**

Movement of capital is not subject to any restriction. Mexico does not apply foreign exchange controls or limitations on repatriation of capital, apart from a dividend tax of 10 per cent when the tax is paid to an individual or a foreign resident.

By law, all employers need to hire Mexican nationals for at least 90 per cent of their workforce. Technicians and professionals need to be Mexican unless there are no Mexican individuals with the required qualifications, in which case the employer may temporarily use foreign workers as long as they do not exceed 10 per cent of the total workforce. This percentage does not apply to senior management (general managers and directors).

National content requirements will play an important role in the oil and gas sector. The HL provides that contractors will have to comply with minimum national content requirements, which will also be progressive, and shall be included in the corresponding contracts. The Ministry of the Economy is responsible for creating the methodology to measure national content through a specialised unit. Failure to meet these requirements will result in penalties.

The initial target of the government is to have a 25 per cent minimum national content requirement for 2015, which should be increased up to 35 per cent by 2025, and which will be reviewed thereafter every five years.
iii  Anti-corruption

Mexican anti-corruption provisions are similar to the UK Bribery Act and the US Foreign Corrupt Practices Act; that is, no solicitation or improper payments may be performed. Anti-corruption laws have recently been enacted, particularly dealing with public tender processes (the Federal Anti-Corruption Law on Public Bids). In addition to this law, Mexico has issued several laws and regulations with transparency and anti-money laundering provisions.

Training on these specific issues has become standard practice for international companies doing business in Mexico.

IX  CURRENT DEVELOPMENTS

The most relevant developments in the oil and gas industry relate to the long-awaited energy reform which has finally been approved by Congress. The general consensus is that the energy reform fully opens the market and the investment opportunities in Mexico. In a nutshell, the energy reform:

a  enables private participation, both national and foreign, in upstream and downstream activities that have been traditionally performed by the state;

b  creates a sustainable fiscal regime for Pemex and other state-owned productive companies, allowing it to reinvest part of its revenue;

c  converts Pemex into a participant and competitor in the Mexican and international markets;

d  allows for the awarding of licences, production or profit sharing contracts, and services contracts, allowing contractors to book reserves (as long as there is clarification with respect to state ownership of the actual unproduced reserves); and

e  creates an organised regulatory environment in the sector, intended to provide transparency and security to investors in the sector.

During 2015, several rules and guidelines were issued by the NHC and the Ministry of Finance. Notably, the Ministry of Finance issued rules regarding accounting procedures and bidding guidelines for contractors to follow in all contracting made to comply with contracts. These rules impose strict surveillance of operations, in order to ensure that transactions are made under an arm’s-length basis, particularly for cost recovery purposes. Technical rules and guidelines are being issued by the NHC to regulate the metering, transfer and determination of quality of hydrocarbons produced to accurately calculate compensation for the state and contractors.
Chapter 17

MOZAMBIQUE

Pedro Couto, Telmo Ferreira, Paulo Ferreira, Márcio Paulo and Gisela Graça

I INTRODUCTION

The Strategic Plan for the Concession of Areas for Petroleum Operations published on 8 June 2009 states that the sedimentary basins in Mozambique have areas with great potential for the occurrence of oil. The Mozambique Basin, which is 300,000km², has a density of around one well per 8,000km² onshore and one well per 17,000km² offshore, while the Rovuma Basin, which is 60,000km², has a density of one well per 17,000km² onshore and none offshore.

In 2004 Sasol Petroleum International acquired the rights to explore gas in Pande-Temane, southern Mozambique.

The project includes a pipeline which runs from the gas fields in Pande-Temane to the Secunda plant in South Africa. The gas fields presently produce 147 million gigajoules of natural gas per year, with only 3 million gigajoules being consumed by Mozambique.

Furthermore, in 2012, Mozambique emerged as a new giant in natural gas with the discoveries of more than 100 trillion cubic feet in the Areas 1 and 4 of the offshore Rovuma Basin.

The main players in the Areas 1 and 4 of the Rovuma Basin include, among others, Anadarko, ENI, Total, Wentworth, Mitsui, Galp Energia, PTTEP, Bharat Petroleum, Videocon and Kogas. Control of the country’s upstream oil industry rests with the state-owned upstream oil company Empresa Nacional de Hidrocarbonetos de Mocambique (ENH), which has exclusive rights to explore for and develop petroleum in Mozambique, and is permitted to exercise these rights in association with foreign investors.

Due to these major discoveries the two operators leading the exploration in the Rovuma Basin Areas 1 and 4 (Anadarko and ENI) indicated that the volume of proven gas reserves justifies construction of a liquefied natural gas (LNG) facility on the northern coast.

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1 Pedro Couto is the chairman, Telmo Ferreira is the managing partner, and Paulo Ferreira, Márcio Paulo and Gisela Graça are senior associates at CGA – Couto, Graça & Associados.
of Mozambique, which also allowed in December 2015 the achievement of a unitisation agreement. The two companies are already making efforts to develop an LNG project that will receive gas from the offshore fields and pre-treat and process it in preparation for storage and export. Anadarko, ENI and their respective partners hope to make a final investment decision by the end of 2016 or early 2017 on whether to proceed with the construction of the LNG facility. Simultaneously, ENI is also exploring the possibility of developing a Floating LNG Facility, which already has the approval of its respective plan of development granted by the government of Mozambique, in which is considered to be a step progress toward the final investment decision of what could be the first floating LNG facility in Africa.

II LEGAL AND REGULATORY FRAMEWORK

Mozambique has a codified legal system. There are two main regulatory bodies: the parliament (which approves laws) and the Council of Ministers (which approves decree-laws).

i Domestic oil and gas legislation
The main legislation relating to the oil and gas sector in Mozambique is as follows:

a the Constitution of the Republic of Mozambique;

b Law 21/2014 of 18 August, which approves the Petroleum Law;

c Decree 34/2015 of 31 December, which approves the Petroleum Law Regulations;

d Decree-Law 2/2014 of 2 December, which establishes a special legal and contractual regime applicable to the LNG Project of Areas 1 and 4 of the Rovuma Basin;

e Law 27/2014 of 23 September, which establishes the Specific Regime of Taxation and Fiscal Benefits for Petroleum Operations;

f Decree 32/2015 of 31 December, which approves the Regulations on the Specific Regime of Taxation and Fiscal Benefits for Petroleum Operations;

g Decree 56/2010 of 22 of November, which approves the Environmental Regulation for Petroleum Operations;

h Decree 63/2011 of 7 December, which provides the legal regime and mechanisms and procedures for the employment of foreign citizens under the Petroleum Law and Mining Law;

i Ministerial Diploma 272/2009 of 30 December, which approves the Regulations on the Licensing of Petroleum Installations and Activities;

j Law 15/2011 of 10 August, which establishes the legal framework of public-private partnerships, large-scale projects and business concessions; and

k Decree 16/2012 of 4 June, which approves the Regulation of the Law of Public-Private Partnerships, Large-Scale Projects and Business Concessions.

The most important legislation is the Petroleum Law, which was approved by the Mozambican parliament on 14 August 2014 and entered into force on the date of its publication in the government’s Official Gazette (i.e., 18 August 2014).

The main objectives of the Petroleum Law are as follows:

a the need to convert matters related with the policies and objectives of the Mozambican government, included in concession contracts, in rights and obligations regulated by law and ensure that the scope of the law covers all stages of petroleum operations, in accordance with the applicable principles of public international law;
the need to follow up the development of legal and fiscal regimes worldwide and to follow the principles of social and economic policies, notably protection of national interest, promotion of local development, protection of environment and the rational use of petroleum resources;

c the need to have a more transparent and predictable legal framework for the petroleum industry and make Mozambique an attractive destination for investments in the petroleum industry; and

d the need to include in the legal framework certain branches of the petroleum industry (LNG), as well as certain resources (methane gas present in coal layers), avoiding the approval of contracts for these resources outside the procedures established in the relevant legislation.

The Petroleum Law expressly provides that the rights arising under concession agreements entered under the old Petroleum Law are qualified as ‘acquired rights’ and as such shall remain valid and unaffected by the Petroleum Law.

ii Regulation

The oil and gas legal framework in Mozambique entails interaction and cooperation among different governmental institutions. The following governmental bodies are relevant and have a direct bearing on oil and gas operations in Mozambique.

The Council of Ministers is the body competent to approve concession contracts.

The Ministry of Mineral Resources and Energy is the governmental body that directs and executes the policies within the ambit of geological investigation and exploration of the mineral resources including the coal and hydrocarbons. It also has custody over the petroleum operations and over the National Institute of Petroleum (upstream).

The National Institute of Petroleum (INP) was created to manage the petroleum resources of Mozambique and administer the related operations for the benefit of the society, and in compliance with the existing laws, government policies and contractual commitments.

The INP is also the Mozambican oil and gas regulator and has the following duties and competences:

a regulation and control of the activity of research, exploration, production and transport of petroleum, as well as proposing policies of development and rules respecting the petroleum operations;

b organisation, maintenance and consolidation of the information and technical data relating to the activities of the petroleum industry, of the national petroleum reserves and the related information;

c conduct of the process of attribution of exploration, production, development and the transport of petroleum;

d normalisation, approval and homologation of the equipment to be used in the operations relating to the petroleum sector;

e proposal and provision of the legal diplomas necessary for the functioning of the petroleum sector and the provision of opinions on such draft laws;

f regulation of activities relating to petroleum operations;

g promotion of free competition and the prevention of abuse of dominant positions and unfair competition;

h preparation and launch of public tenders for concessions and entering into other contracts;
Mozambique

i issue of opinions on the attribution, renewal and change of concessions;
j control of compliance by the contracting parties to the terms of the concession contracts and the law;
k promotion and development of the prospecting and exploration of petroleum;
l participation in the definition of contract areas, minimum work requirements and of expenses to the defined with the concession contracts; and
m supervision of prospecting and exploration and of compliance with the work programme by concessionaires.

The Petroleum Law provides that an authority – the High Authority for the Extractive Industry – would be created to oversee extracting industries, nevertheless, it is silent as to what the powers of such authority shall be. In particular, it is uncertain whether it will be a regulatory authority or just an ombudsman, and to what extent its role and powers will not conflict or overlap with those of the National Petroleum Institute.

iii Treaties
Mozambique has entered into bilateral investment treaties with the following countries: Algeria, Belgium, China, Cuba, Denmark, Egypt, Finland, France, Germany, India, Indonesia, Italy, Mauritius, Netherlands, Portugal, South Africa, Spain, Sweden, Switzerland, the United Kingdom, the United States, Vietnam and Zimbabwe.

In addition, it has double taxation treaties in place with the following countries: Botswana, India, Italy, Macau, Mauritius, Portugal, South Africa, the United Arab Emirates and Vietnam.

III LICENSING

The types of concession contracts prescribed in the Petroleum Law are the following:
a Reconnaissance concession contract – reconnaissance concession contracts entered into under the Petroleum Law:
• can only be entered into on a non-exclusivity basis;
• shall be for a non-renewable two-year term; and
• may not give rise to a right of first refusal in the granting of prospection and production concession.
b Prospection and production concession contract – under the Petroleum Law these concession contracts grant an exclusive right to conduct petroleum operations and a non-exclusive right to build and operate the infrastructures used in the production and transportation of petroleum. Also:
• the approval of the government shall be required for joint-bidding or joint-operation agreements;
• the right to carry prospection activities cannot arguably be extended beyond eight years even if necessary to complete the works;
• there is no specified term for the extension of prospection activities in case a discovery is made; and
• there is no specified term for the extension of the contract for the purpose of production.
c Oil or gas pipeline system concession contract – An oil pipeline or a gas pipeline system concession contract grants the right to construct and operate oil pipeline
or gas pipeline systems for the purpose of transporting crude oil or natural gas, in those cases that such operations are not covered by an exploration and production concession contract. An oil pipeline or a gas pipeline system concession contract shall be accompanied by the relevant development plan, which is an integral part of the concession contract.

d  Infrastructure concession contract – the Petroleum Law foresees concession contracts for the construction and operation of infrastructures. Such concessions shall grant the right to build and operate infrastructures for petroleum production, including liquefaction. Such concessions shall only be required if the relevant infrastructure is not covered by an approved plan of development for prospection and production.

In addition to the types of concession contracts mentioned above, the Petroleum Law also contains a provision in respect to gas liquefaction, providing that the government may authorise concessionaires that have discovered deposits of oil and non-associated gas to develop projects for the design, construction, installation, ownership, financing, operation, maintenance, use of wells, installations and ancillary equipment, either onshore or offshore, for the production, processing, liquefaction, delivery and sale of gas in the domestic or foreign markets. It is therefore clear that liquefaction activities, either onshore or offshore, can be undertaken under EPCCs, subject to government approval but without the need of a separate agreement.

All concession contracts for exploration and production activities must be granted by way of public tender, while concession contracts for other petroleum activities (e.g., an infrastructure concession contract) may result from public tender, simultaneous or direct negotiation.

IV ASSIGNMENTS OF INTERESTS

Any direct transfer of rights and obligations granted under the concession contract, to an affiliate or to a third party, shall be made in accordance with Mozambican law and is subject to the government’s approval. The Petroleum Law expressly provides that indirect transfer of participating interests, notably by way of change of control of the concessionaires, shall be considered as a transfer of rights and obligations under an EPCC, hence requiring government approval.

The above-mentioned assignments may also be subject to the payment of capital gains tax, since capital gains derived from the sale of shares of a resident company by a non-resident without a permanent establishment in Mozambique are fully taxed. The tax relief previously available depending on the holding period of the shares has also been revoked, and gains resulting from a direct or indirect transfer between non-residents of capital shares or other interests and participatory rights involving assets located in Mozambique are deemed to be obtained in Mozambique (regardless of where the sale takes place and regardless of whether the transfer is gratuitous or for consideration).

V TAX

The Petroleum Law expressly provides that the holders shall pay, along with specific taxes on petroleum operations:

a  income tax;
Furthermore, the Specific Regime of Taxation for Petroleum Operations aims to comprise, in a single law, the specific regimes of taxation and fiscal benefits applicable to petroleum operations and to adopt specific rules in terms of income taxes for petroleum operations, notably those referring to restrictions on the transfer of costs and income between different petroleum titles.

This legislation also includes amortisation rates applicable to assets used in this sector of activity, the regime applicable to capital gains emerging from transactions undertaken in respect to this sector of activity, the requirement to submit annual balance sheets and profit and loss accounts certified by an independent and authorised auditor and to proceed to the update of the list of goods that may be imported by petroleum undertakings, which are exempted from customs duties.

This Specific Regime of Taxation for Petroleum Operations is applicable to legal persons incorporated and registered in Mozambican territory, as well as to natural persons, national and foreign, who undertake petroleum operations under a concession contract subject to Mozambican jurisdiction, and aims to align the legislation with international practices applicable to the petroleum sector, comprising all tax matters relevant to the industry, allowing for easy consultation and interpretation of the legislation and ensuring the improvement of the business environment through the mobilisation of additional revenues.

VI ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In recognition of the specifics of petroleum operations, special environmental regulations for petroleum operations have been approved through Decree 56/2010 of 22 November (the Environmental Regulation for Petroleum Operations).

This Regulations defines the procedures and mechanisms for environmental impact assessment for petroleum operations and the measures of prevention, control, mitigation and rehabilitation of the environment, and apply to petroleum operations of public and private initiative.

For the purposes of the categorisation of the petroleum operations, activities are classified as:

- **Category A**: activities subject to the conduct of an environmental impact study;
- **Category B**: activities subject to the conduct of a simplified environment study, except in the cases foreseen in the Regulations; and
- **Category C**: activities subject to compliance with the standards of good environmental management.

The execution of an environmental impact study is mandatory prior to the commencement of Category A activities, constituting an obligation of the proponent of the activity that shall submit it to the Ministry of Environmental Affairs.

The environmental impact study also comprises decommissioning and rehabilitation plans.
The execution of a simplified environmental study is mandatory for Category B activities, constituting an obligation of the proponent of the activity to perform it and submit the respective report to the Ministry of Environmental Affairs. Category C activities are those that by their nature do not entail damage to the environment.

The Ministry of Environmental Affairs issues a declaration of exemption for the activities foreseen under Category C.

The environmental impact study and the simplified environmental study shall be subject to public participation, consisting in public consultation of the natural and legal persons, public or private, directly or indirectly interested and affected by the execution of Petroleum Operations, being mandatory for Category A Activities and Category B Activities.

After approval, as applicable, the Ministry of Environmental Affairs shall issue the respective Environmental License for Category A and Category B activities, within eight days after the payment of the fees due.

The environmental license is valid for a period of five years. It is renewable for another five years upon request, which shall be submitted by the proponent to the Ministry of Environmental Affairs 180 days before the end of its validity.

Moreover, with regards to decommissioning, the Ministerial Diploma 272/2009 of 30 December, which approves the Regulations on the Licensing of Petroleum Installations and Activities, contains certain provisions on the decommissioning phase that are applicable to concessionaires, operators, contractors and subcontractors and other entities involved in petroleum operations or petroleum activities within Mozambican territory.

An authorisation granted by INP (a decommissioning licence) is required that allows the holder to commence the closure of the petroleum facilities and the restoration of the sites affected by the petroleum activities.

VII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

The Petroleum Law requires that:

a any entity that directly or indirectly own or control entities with rights under concession agreements must be established in, registered in and managed from a transparent jurisdiction (i.e., a jurisdiction where the government is able to independently verify their ownership, management and control and tax status); and

b companies that apply for concessions deposit a document evidencing their incorporation and identifying their shareholders and providing information on their respective shareholdings.

According to the Mozambican Commercial Code, if a foreign company intends to carry out any activity in Mozambique for more than one year, it has to set up a permanent establishment in Mozambique and appoint a representative who shall be resident in the country. The foreign company will have to allocate capital for the purposes of the implementation its activity in Mozambique, and register any resolution adopted in relation to such representation with the Legal Entities Registration Office. The representation and the foreign company’s representative also have to be duly registered with the Registration Office.

Moreover, if the foreign company carries on business in Mozambique (without having incorporated a Mozambican subsidiary or established a branch), for a period of more than...
180 days, the Mozambican tax authorities may consider that the foreign company has a permanent establishment in Mozambique and it shall be subject to taxation as if it were a resident entity.

Bearing in mind the above, it is advisable that a foreign company intending to develop business activities in Mozambique either incorporates a Mozambican subsidiary, governed by the laws of Mozambique, or establishes a branch that will develop and conduct the business of the foreign company in Mozambique.

It is recommended to incorporate a subsidiary in order to limit the liability for the subsidiary’s debts to the assets of such subsidiary since, in case of a branch, the parent company will be fully liable for the debts resulting from the activity of the branch, which has no legal personality under the Mozambican legal system.

There are two main forms of companies in Mozambique: company limited by quotas (LDA) and company limited by shares (SA). The LDA is the simplest and most commonly used form of limited liability company in Mozambique, while the SA has a more sophisticated corporate governance structure than the LDA and is typically used in connection with large-scale projects.

In terms of procedures, a company incorporation procedure starts with the submission of a name reservation application, followed by the issuance of a name reservation certificate, opening of a bank account to deposit the company’s share capital, signature before a public notary of the deed of incorporation, publication of the articles of association in the Official Gazette and application for commercial registration in the government’s Official Gazette. This process takes on average one month.

ii Capital, labour and content restrictions

Mozambique exchange control policies

A company is generally required to comply with the procedures and formalities relating to foreign exchange transactions that are or may come to be in force in the Republic of Mozambique. The Exchange Control Law provides under Article 28(f) of Law 11/2009 of 11 March 2010, which in any concession contract, the concessionaires and subcontractors shall be considered special cases, and that the decree that approves this contract shall be considered special legislation. Subject to the minimal restrictions indicated, the company is generally permitted:

a to open, keep and operate one or more accounts denominated in Mozambican currency with any bank in the Republic of Mozambique and to dispose freely of the sums deposited therein without restriction;

b to open, keep and operate one or more foreign currency accounts with any bank in the Republic of Mozambique authorised for the purpose by the Bank of Mozambique in order to freely import and deposit into such account funds required for the conduct of petroleum operations; to convert to Mozambican currency the foreign convertible currencies accepted by banks in the Republic of Mozambique at rates of exchange quoted by commercial banks operating in the Republic of Mozambique;

c upon request addressed to the Bank of Mozambique and in accordance with the procedures in force that grant the company the right to a special authorisation, to open and operate bank accounts with banks abroad that are correspondents of licensed banks in Mozambique, for purposes of depositing the proceeds of sale, other funds from any other lawful source and payments made abroad under the EPCC;
(in addition and without prejudice to the flat tax due) to freely declare and pay dividends to its shareholders and to transfer them abroad in the terms of the foreign exchange regulations in force; and

(subject to approval by the Bank of Mozambique and in the terms of the legislation in force) to contract external loans, pay interest, capital and other expenses.

The generally permissible exchange control regime applicable in Mozambique is nonetheless subject to a number of obligations incumbent upon a company. These include:

- the obligation to report periodically on the banking transactions involving the accounts referred to above. A company is also obligated to inform its banker to provide the Bank of Mozambique with quarterly copies of extracts of such accounts, whereby the Bank of Mozambique has also the right to order audits on such accounts. Moreover, a company is also required to waive its rights to banking secrecy for the benefit of the Bank of Mozambique in relation to the accounts mentioned above so as to facilitate such audits; and

- the obligation to submit to the Bank of Mozambique a summary of all currency received, imported, remitted and maintained in accounts abroad during the relevant reporting period, within 30 days from the end of each quarter.

Employment of foreign citizens in the petroleum and mining industry in Mozambique

The Petroleum Law introduces a new requirement in respect of the hiring of a workforce for petroleum exploitation companies, which shall be published in newspapers with wider readership in the country, or through radio, television and the internet, indicating the place of application, conditions required and publication of results. This requirement does not seem to apply to subcontractors.

Decree 63/2011 of 7 December provides the legal regime and mechanisms and procedures for the employment of foreign citizens under the Petroleum Law and Mining Law. This legal regime is applicable to all employers, domestic and foreign, and all foreign employees working in these sectors, and provides a regime of quotas for the employment of foreign citizens, where employers may employ foreign citizens by simply giving notice of the employment to the Ministry of Labour or an entity to whom the minister has delegated this competency, in the period of 15 days after the admission of the employee, subject to the following quotas:

- 5 per cent of the total number of employees, in large enterprises (an enterprise employing more than 100 employees);
- 8 per cent of the total number of employees, in medium-sized enterprises (an enterprise employing more than 10 but not more than 100 employees); and
- 10 per cent of the total number of employees, in small enterprises (an enterprise employing up to 10 employees).

If the enterprise has already fulfilled the quotas, it is possible to employ foreign citizens by means of requesting a work authorisation, addressed to the Ministry of Labour. In these cases, the admission of the foreign citizen shall only proceed if the employee has the required academic and professional qualifications, and it is proved that there are no nationals with such qualifications.

In petroleum or mining investment projects approved by the government (through the Investment Promotion Centre) that contemplate the employment of foreign citizens in
a smaller or greater percentage than foreseen above, work permits shall not be required, and it shall be sufficient for notice to be given to the Ministry of Labour within 15 days after the foreign citizen enters into Mozambique.

Finally, the law also provides for short-term work, which is considered to be work performed by a foreign citizen that does not exceed 180 days per year, followed or interrupted. This short-term work does not require any work authorisation, it only being necessary to remit, within 15 days following the arrival of the foreign citizen to the country, a communication to the Ministry of Labour mentioning the identity of the employee, qualifications, reason for their hiring and activities that will be performed, dates when the employee will be in the country, etc.

iii  Anti-corruption

Law 6/2004 of 17 June, which introduces complementary mechanisms to fight corruption, provides that within all contracts in which the state, municipalities or other public bodies are parties, it is mandatory to include an anti-corruption clause through which the parties commit to avoid offering, directly or indirectly, advantages to third parties, and not request, promise or accept offers with the purpose of obtaining a more favourable judgment on the services to be provided.

If the contract does not include the above-mentioned clause, it will be deemed null and ineffective.

Moreover, on 11 May 2012 the Mozambican parliament approved a law on ethics and conflicts of interest, presented as the Public Probity Law. This law establishes the basis and the legal regime related to public morality and respect for public assets, by public servants.

This law is applicable to all public servants, as well as to private entities circumstantially vested with public powers. A public servant is defined as a person who carries out a mandate, assignment, job or tasks in a public entity, in virtue of election, appointment, hiring or any other form of relationship, regardless of being temporary or without remuneration.

iv  Forms of investment

The Petroleum Law expressly regulates the forms under which direct investment in petroleum activities shall take place. In particular, the Petroleum Law foresees that the investment by the state can be made through the appreciation of existing resources and also through other forms of investment that shall be defined by the government.

VIII  CURRENT DEVELOPMENTS

i  LNG project

A project for the construction of LNG facilities in the northern Mozambican province of Cabo Delgado is currently being discussed.

The US company Anadarko heads the consortium that has discovered large quantities of gas in Area 1 of the Rovuma Basin, off the Cabo Delgado coast. Similar discoveries have been made in the adjacent Area 4 by a consortium headed by the Italian energy company ENI. Anadarko and ENI are working together to develop the processing facilities and eventually to export the gas. The main markets are expected to be Japan and other consumers in the Far East.
As mentioned above, the concessionaires of Areas 1 and 4, respectively, of the Rovuma Basin expect to make a final investment decision by the end of 2016/early 2017 on whether to proceed with the construction of the LNG facility.

To facilitate the implementation of this project, the government of Mozambique approved the Decree-Law 2/2014 of 2 December, which was passed to establish a special legal and contractual regime to be applied to any project developed in Areas 1 and 4 of the Rovuma Basin, including the exploration, extraction and production of natural gas and associated LNG liquefaction activities (each a Rovuma Basin Project).

Simultaneously, ENI is also exploring the possibility of developing a floating LNG facility, which already has the approval of its respective plan of development granted by the government of Mozambique, in which is considered to be a step progress toward the final investment decision of what could be the first floating LNG facility in Africa.

ii African Renaissance

A joint venture agreement between Mozambican, South African and Chinese partners (notably Empresa Nacional de Hidrocarbonetos (ENH), Profin Consulting Sociedade Anonima (Profin), China Petroleum Pipeline Bureau (CPP), China Petroleum & Technology Development Corporation (CPTDC) and Progas Investment Group (Pty) Limited) has been signed for the building of a gas pipeline from the northern Mozambican district of Palma to the South African province of Gauteng (the ‘African Renaissance’).

The project is presently going through viability studies which is estimated to cost US$45 million.

The total cost of the 2,600-kilometre pipeline is put at US$6 billion and it is expected that China will provide credit for 70 per cent of this (US$4.2 billion).

iii ENI’s potential farm down

There have been strong rumours by the press that Exxon Mobil Corp is in advanced negotiations with Eni SpA over acquiring a minority stake in natural-gas discoveries off Mozambique Area 4 Rovuma Offshore and also in talks with Anadarko Petroleum Corp over acquiring a stake in the adjacent Area 1 in Mozambique’s offshore Rovuma Basin.

iv Blocks auction

Mozambique launched on 23 October 2014 its fifth oil and gas bidding round, with a total of 15 blocks comprising the offshore Rovuma, offshore Angoche, offshore Zambezi and onshore Pande-Temane and onshore Palmeira areas (the area on offer covered approximately 74,402km²).

After evaluation of the bids, the following operator lead groups have been invited to commence negotiations for an exploration production concession contract:

\( a \) Angoche Area A5-A ENI Mozambico S.p.A;
\( b \) Angoche Area A5-B ExxonMobil E&P Mozambique Offshore Ltd;
\( c \) Zambezi Area A5-C ExxonMobil E&P Mozambique Offshore Ltd;
\( d \) Zambezi Area A5-D ExxonMobil E&P Mozambique Offshore Ltd;
\( e \) Pande/Temane Area PT5-C Sasol Petroleum Mozambique Exploration Ltd; and
\( f \) Palmeira Area P5-A Delonex Energy Ltd.
NEW ZEALAND

Paul Foley

I INTRODUCTION

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.

In addition, New Zealand has the fourth largest ‘Exclusive Economic Zone’ in the world, resulting in vast potential for exploration. New Zealand’s producing oil and gas fields are located in the Taranaki basin on the west coast of the North Island. Within New Zealand’s Exclusive Economic Zone there are a significant number of other petroleum basins that are expected to yield substantial oil and gas deposits.

Oil

In 2016 low oil prices have had a major effect on the industry. The total production of crude, condensate and naphtha in New Zealand fell 8.4 per cent between December 2015 and March 2016.\(^2\) In the same quarter exports were down 24 per cent, however, this was mainly due to stock build.\(^3\) 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 March 2016 New Zealand’s only refinery’s output of petrol reached its highest level in over 10 years, as a recent upgrade came into effect. In response to the increase in production, petrol imports fell.\(^4\)

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1 Paul Foley is a partner at Minter Ellison Rudd Watts.
3 At 3.
4 At 3.
Gas
Total net gas production rose 8.1 per cent from the December 2015 quarter to the March 2016 quarter. However, production was still down 1.1 per cent when compared with the March 2015 quarter. This continues an overall downward production trend. Production of gas is dominated by the Pohokura and Maui fields, which are responsible for over half of New Zealand's domestic gas production.

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. However, gas provides vital fuel for electricity generation and is the primary fuel for industry. Natural gas is transmitted throughout the North Island through high-pressure gas transmission pipelines that 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
The oil and gas sector's importance continues to be recognised by the government, which is committed to unlocking and maximising New Zealand’s petroleum potential, with a specific focus on exploration of New Zealand’s offshore deepwater basins.

In 2011 the government released the New Zealand Energy Strategy 2011–2021, Developing our Energy Potential. The strategy sets out how the government intends to help develop New Zealand’s petroleum resources, in part by increasing exploration activity and improving knowledge of New Zealand’s petroleum basins. 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.

5 At 3.
6 At 3.
7 At 3.
New Zealand

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.9 A permit must be obtained from the Crown to carry out any prospecting, exploration or mining activities.10 If extracted in the course of activities authorised by a permit, ownership of petroleum passes to the holder of that permit.11

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 CMA is supplemented by other important pieces of subordinate legislation including the:

a  Continental Shelf Act 1964, which extends the application of the CMA to include petroleum in the seabed and subsoil of the continental shelf;

b  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;

c  Crown Minerals (Royalties for Petroleum) Regulations 2013, which cover royalties and royalty reports for petroleum mining permits issued after 24 May 2013;

d  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; and

e  Crown Minerals (Petroleum Fees) Regulations 2006 which outline the fees payable under the CMA for petroleum permits among other matters.

Environmental legislation relevant to the oil and gas sector is discussed at Section VII, infra. The most important statutes are the Resource Management Act 1991 (RMA) and the Exclusive Economic Zone and Continental Shelf (Environmental Effects) Act 2012 (EEZCSA).

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New Zealand has developed an internationally competitive royalty regime. The regime stipulates that mining permit holders pay either an *ad valorem* royalty or an accounting profit royalty, whichever is greater in any given year. The royalty rates are either:

- 5 per cent *ad valorem*, that is 5 per cent of the net revenue obtained from the sale of petroleum; or
- 20 per cent of the accounting profit of petroleum production.

### 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 the regulation of the industry.

### iii 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 39 double tax agreements in force. These include agreements with Australia, China, the United Kingdom and the United States.

### III LICENSING

#### i Overview

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

- a permit under the CMA;
- the required consents under the RMA or the EEZCSA; and
- if necessary, an access arrangement with the landowner 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.

#### ii Prospecting

Petroleum prospecting permits (PPP) are required for prospecting activities such as desktop studies, grab sampling and geophysical, aerial and seismic surveys. An application for a PPP is submitted in respect of an area nominated by the applicant, and is assessed on the applicant’s technical and financial capability to undertake the proposed work and on the applicant’s record of compliance. Prospecting permits are granted on the basis that prospecting will
increase knowledge of New Zealand’s petroleum resources; if the proposed prospecting is unlikely to materially add to existing knowledge, a permit will only be granted if special circumstances exist.\(^\text{12}\)

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.\(^\text{13}\) They are granted for a maximum four-year period, with no right of extension.

iii Exploration

A petroleum exploration permit is required for activities such as seabed sampling, detailed seismic surveying and the drilling of exploration wells. Exploration permits are allocated in an annual tender process known as a petroleum exploration permit round (or block offer).\(^\text{14}\) NZP&M will typically seek nominations from interested parties on areas for inclusion in an upcoming offer; areas where prospecting permits have been undertaken will usually be included where requested by interested parties.\(^\text{15}\)

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.\(^\text{16}\) 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.\(^\text{17}\) 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.\(^\text{18}\) Exploration permits include a subsequent right to apply for a mining permit.\(^\text{19}\)

Permit holders must notify NZP&M as soon as practicable, and not later than 20 working days after making a discovery of petroleum.\(^\text{20}\)

\(^\text{13}\) Minerals Programme for Petroleum 2013, at 4.2.3 and 6.2.5.
\(^\text{14}\) Minerals Programme for Petroleum 2013 at 7.2.
\(^\text{15}\) Minerals Programme for Petroleum 2013, at 7.3.1.
\(^\text{16}\) Minerals Programme for Petroleum 2013, at 7.2.2.
\(^\text{17}\) Crown Minerals Act 1991, Sections 35(3) and 35(4); Minerals Programme for Petroleum 2013 at 7.8.
\(^\text{18}\) Minerals Programme for Petroleum 2013, at 7.3.
\(^\text{20}\) Minerals Programme for Petroleum 2013, at 7.11.1.
iv Production
Petroleum mining permits (PMP) authorise the holder of a permit to mine petroleum in a particular area. 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. A mining permit can be granted for up to 40 years.

v Iwi and Hāpu 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.

vi Information sharing
Permit holders of all types have an obligation to collect and share with NZP&M, particular information. In the case of exploration and mining permits, NZP&M will make this information publicly available five years after it is collected, or when the permit to which it relates expires. Information obtained under a prospecting permit will generally not be made publicly available until 15 years after it is collected, unless the information is collected by a non-speculative prospector and a block offer for the area to which the prospecting permit relates has closed.

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.

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

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24 Crown Minerals Act 1991, Section 33C.
exception to this rule for minimum impact activities that, subject to conditions, may be carried out without an access arrangement provided that written notice is provided to the landowner and occupier.\textsuperscript{29}

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.\textsuperscript{30} Schedule 4 protects land which 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.

\section*{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. 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.

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.

\section*{V ASSIGNMENTS OF INTERESTS}

\subsection*{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

\textsuperscript{29} Crown Minerals Act 1991, Section 49.

from the parent entity of the incoming permit holder. There is a small fee payable – currently NZ$1,022.22. 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 also applies to changes of control of a permit holder.

The government generally does not have a right of first refusal or preferential purchase right in the event of a transfer.

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 Inland Revenue 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 20 countries (mostly offshore financial centres) that have concluded tax information exchange agreements (TIEAs) with New Zealand. However, only 11 of these are currently in force. New Zealand is currently negotiating a further 10 TIEAs.

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.

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
New Zealand

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(s), 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 Rule Part 200
Marine New Zealand administers the Maritime Rule Part 200, which provides rules for offshore petroleum installations. Part 200 requires operators to develop a discharge management plan that 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 (EEZ) 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.

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;
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 companies legislation, all New Zealand companies are required to have at least one director who is resident in New Zealand, or resident in, and a director of a company resident in, Australia (a prescribed country). The list of prescribed countries may be expanded in the future.

ii Capital, labour and content restrictions

There are no generally applicable restrictions on the movement of capital or access to foreign exchange in New Zealand. Oil and gas operators are permitted to hire foreign workers, provided that immigration and employment requirements are met. There are no local content or local hiring requirements.

iii Overseas Investment Act 2005

The New Zealand government regulates foreign investment though the Overseas Investment Act 2005 (OIA). Under the OIA an overseas person must obtain consent for a transaction which will result in overseas investment in ‘significant business assets’ or ‘sensitive land’.

An overseas investment in significant business assets is defined as: 31

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 or acquiring property used to carry on a business if the consideration exceeds NZ$100 million.

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.32 A permit under the CMA or a licence under the Continental Shelf Act is not considered an interest in land for the purpose of the OIA.

Consent will generally be granted to an overseas investment where the overseas person can demonstrate that they have the business experience, acumen and financial commitment to make the investment successful and that the investment will, or is likely to, benefit New Zealand.


32 Overseas Investment Act 2005, Section 12 and Schedule 1.
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.\(^{33}\)

v  **Anti-corruption**

New Zealand has a reputation for being a country with a transparent system of government and low levels of corruption. In 2015 New Zealand was ranked the fourth-least corrupt country in Transparency International’s corruption perceptions index.

Bribery and corruption are offences in relation to both the private sector,\(^{34}\) and the public sector.\(^{35}\) 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 has signed, but not ratified, the United Nations Convention against Corruption.

**IX CURRENT DEVELOPMENTS**

i  **Permit changes and withdraws**

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 has 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 will have increased. To amend the conditions of a permit, permit holders must apply to NZP&M at least 90 days before a permit condition is due to have been completed. Applications must be supported by sufficient justification for the change to be approved.

Where the change involves a total withdrawal from a permit before committed work is done, the permit holder can be required to complete that work or, if released from that obligation in that instance, the holder’s future ability to obtain permits in New Zealand may be adversely affected.

ii  **Trans Pacific Partnership (TPP)**

New Zealand is currently negotiating a regional free trade agreement with 11 other Asia-Pacific countries, including the United States. The aim of the agreement is to lower

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\(^{34}\) Secret Commissions Act 1910.

\(^{35}\) Crimes Act 1961.
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.

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 & Safety at Work Act 2015 came into force on 4 April 2016. The Act, which was modelled on Australian health and safety legislation, introduced the concept of persons conducting a business or undertaking (PCBUs). PCBUs have a primary duty of care to ensure ‘so far as is reasonably practicable’ the health and safety of workers and others. The implications of the new PCBU concept require particular consideration by non-operators within joint ventures.

The Act also introduced strict new due diligence obligations on directors, partners and senior managers of businesses operating in New Zealand. The penalties for non-compliance for both individuals and companies have increased under the new Act, and there is likely to be a stronger focus from the regulator on ensuring the health and safety of workers in the future.
Chapter 19

NIGERIA

Israel Aye, Laura Alakija, Constance Okhilua and Esther Onoji

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 indicate that the Nigerian government intends to break the PIB into three separate bills to deal with the industry reform, fiscal framework and revenue management of the oil and gas industry. These bills are yet to be presented on the floor of the National Assembly for consideration and eventual passage into law.

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1 Israel Aye is the managing partner, Laura Alakija is a partner, and Constance Okhilua and Esther Onoji are senior associates at Sterling Partnership.
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 revisions. The current draft was updated 2012.
The upstream sector, the most active sector of the Nigerian industry, is largely export-focused and until recently was dominated by international oil companies. The Nigerian government’s marginal fields licensing regime and its content development drive have given rise to significant levels of indigenous participation within the sector.

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 four 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, was 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 7 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.

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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.


7 Constitution of the Federal Republic of Nigeria 1999 (as amended, CFRN) Section 44 (3).

See further, Petroleum Act, Cap P10, Laws of the Federation of Nigeria (LFN) 2004, Section 1(1).


9 Petroleum Act Sections 2, 4 and 9.
The Petroleum Profits Tax Act\textsuperscript{10} – providing the framework under which the federal government obtains revenue from oil and gas operations by way of signature bonuses, royalties and taxes.\textsuperscript{11}

The Deep Offshore and Inland Basin Production Sharing Contracts Act\textsuperscript{12} – accords tax relief incentives to oil and gas companies operating in the Deep Offshore and Inland Basin areas under PSCs.\textsuperscript{13}

The Associated Gas (Reinjection) Act.\textsuperscript{14}

The Nigerian National Petroleum Corporation Act\textsuperscript{15} – establishes the NNPC and empowers it to participate directly in petroleum operations on behalf of the federal government.

The Environmental Impact Assessment (EIA) Act\textsuperscript{16} – providing the framework for assessing the impact of oil and gas projects on the environment.\textsuperscript{17}

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{18}

The Education Tax Act\textsuperscript{19} – providing for the imposition of annual taxes at 2 per cent of assessable profits on oil and gas companies for the development of Nigeria’s educational sector.

The Niger Delta Development Commission (Establishment) Act\textsuperscript{20} – requires 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{21}

The Nigerian Oil and Gas Industry Content Development Act 2010 – providing a framework for promoting participation of Nigerians in the industry and lays down minimum thresholds for Nigerian content utilised by the industry.\textsuperscript{22}

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{23}

\textsuperscript{10} Cap P 13, LFN 2004.
\textsuperscript{11} Ibid, Sections 9, 20, 21–23, 56.
\textsuperscript{12} Cap D3, LFN 2004.
\textsuperscript{13} Ibid, Sections 3, 4 and 5.
\textsuperscript{15} Cap N123, LFN 2004. See particularly, Section 5, 6 and 10.
\textsuperscript{16} Cap E12, LFN 2004.
\textsuperscript{17} Ibid, Section 2 and Paragraph 12 of its Schedule.
\textsuperscript{18} 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{19} Cap E4, LFN 2004.
\textsuperscript{20} Cap N86, LFN 2004.
\textsuperscript{21} Ibid, Section 14 (b).
\textsuperscript{22} See particularly NOGICD Act Sections 11 and 106.
\textsuperscript{23} See particularly, NEITI Act Section. 3.
The Federal Ministry of Petroleum Resources has primary responsibility for policy direction and exercises supervisory oversight over the industry. The Minister of Petroleum Resources (the Minister) issues regulations, guidelines and directives pursuant to the Petroleum Act and other enabling laws. The Department of Petroleum Resources (DPR) is responsible for the day-to-day monitoring of the petroleum industry and for supervising all petroleum industry operations. Other regulators and agencies include: the Federal Ministry of the Environment (FME), NNPC, the Nigerian Content Development and Monitoring Board (NCDMB) and the National Oil Spill Detection and Response Agency (NOSDRA).

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 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), Spain (19 January 2006), Sweden (1 December 2006), Switzerland (1 April 2003), Taiwan (7 April 1994), the United Kingdom (11 December 1990) are in force while bilateral investment treaties with Algeria, Bulgaria, China, Egypt, Ethiopia, Jamaica, Russia, Turkey and Uganda have been signed and are awaiting ratification.

III LICENSING

The licensing regime under the Petroleum Act provides for the following licences.

26 See Petroleum Act, Sections 8 and 9.
27 See NIPC Act, Section 26 (3).
30 Ibid.
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.31

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,32 by the Petroleum Profits Tax Act33 or other law imposing tax on petroleum. The duration is determined by the Minister and for onshore areas and shallow waters is five years,34 inclusive of any period of renewal, while an OPL for Deep Offshore and Inland Basins is 10 years.35

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.

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 bpd36 and 2.5 million bpd37 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

31 Paragraph 3, First Schedule to the Petroleum Act.
32 Paragraph 7, ibid.
33 Cap P13 , LFN 2004.
34 Paragraph 6, First Schedule to the Petroleum Act.
35 Section 2, Deep Offshore and Inland Basins Production Sharing Contracts Act.
37 Member Countries' Crude Oil Production Allocations, Available from www.opec.org/opec_web/static_files_project/media/downloads/data_graphs/ProductionLevels.pdf.
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 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:

\[ \begin{align*}
    a & \quad \text{have a minimum annual turnover of US$100 million and a net worth of at least}
             \text{US$40 million;} \\
    b & \quad \text{own a refinery or sales outlet;} \\
    c & \quad \text{be an established and globally recognised oil and gas marketer with evidence of}
             \text{operations and of volumes of crude handled in the last three years; and} \\
    d & \quad \text{provide a US$1 million performance bond, among other contractual arrangements.}
\end{align*} \]

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.\textsuperscript{38} 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\textsuperscript{39} 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

\textsuperscript{38} First Schedule, paragraph 14, Petroleum Act and Regulation 4 of the Petroleum (Drilling and
Production) Regulations (the Regulations).

\textsuperscript{39} Regulation 4(b) of the Regulations.
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 such fees as the Minister may prescribe and all other information in respect of the assignee and on such terms as the Minister may decide. The Minister may decline consent where he 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 is in all other respects acceptable to the federal government.

iii Challenges
The major challenge with respect to the 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 timelines 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:

- 85 per cent on onshore operations (but 65.75 per cent of the chargeable profits for the first five accounting period of a new company);
- 50 per cent on offshore operations in territorial waters and continental shelf area up to and including 1,000m water depth;

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41 See PIB, Section 194(1) and (2).
43 Section 16, Petroleum Act.
45 CAP C21 LFN 2004.
46 Section 21(2) PPTA.
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.\(^{47}\) The ITC rate applicable to the contract area shall be 50 per cent flat of the chargeable profit for the duration of the PSC;\(^{48}\) and

50 per cent investment tax allowance for contracts signed post-1999.

**ii Petroleum investment allowance rates**

The following petroleum investment allowance rates applicable are:\(^{49}\)

- **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.

**iii Other applicable taxes**

The NDDC\(^{50}\) 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.\(^{51}\)

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 1,000m water depth to 20 per cent in onshore areas of operations. Royalty can be paid in cash or by delivery of an equivalent volume of petroleum.

**iv Tax authority**

The Federal Board of Inland Revenue\(^{52}\) is the policymaking body administering matters of federal tax and has exclusive jurisdiction over petroleum taxation in Nigeria.\(^{53}\)

**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.
gas encountered in the course of oil production, these incentives are also applicable to non-associated gas-utilisation projects. The incentives 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 defaults 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 from petroleum operations. Key laws and regulations are:

a the Mineral Oils (Safety) Regulations;
b the Oil in Navigable Waters Act;
c the Oil Pipelines Act;
d the Environmental Guidelines and Standards for the Petroleum Industry (EGASPIN);
e the Petroleum Refining Regulations;
f the National Oil Spill Detection and Response Agency (Establishment) Act;
g the Environmental Impact Assessment Act;
h the Associated Gas Re-Injection Act; and
i 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.

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:

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54 Section 12 of the PPTA.
55 Subsection 2 further provides for conditions for the incentives.
56 Section 9(1) (b)(iii) of the Petroleum Act.
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.

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).

iii 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. Note, 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 (the Geneva Convention) 1958;
- the United Nations Convention on the Law of the Sea (UNCLOS) 1982; and

EGASPIN (2002) also introduces new offshore decommissioning provisions which mirrors 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 the 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.

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58 Sections 4, 21 and 24 of the EIA Act.
59 Under the Environmental Regulations WEF 1 January 1984, pursuant to the Associated Gas Reinjection Act, 1979.
60 Section 3 of the Associated Gas Reinjection Act, 1979.
61 Article 36 of the Petroleum (Drilling and Production) Regulations, Article 32 of the Petroleum Refining Regulation.
63 EGASPIN, 327.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
The Companies and Allied Matters Act\(^{64}\) (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.\(^{65}\) 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:

- **a** incorporation of the entity with the Corporate Affairs Commission;
- **b** registration of the company’s tax obligations with the FIRS;
- **c** registration with the Nigerian Investment Promotion Commission (NIPC)\(^{66}\) (for companies with foreign participation); and
- **d** registration with the DPR for a permit. Permits are granted in the general, major or specialised categories depending on the nature of services the entity intends to carry on in the industry.

The process for establishing a Nigerian entity and making the vehicle operationally ready will take an average of three to four months subject to the availability of the required information and supporting documentation as requested by the relevant agencies.

ii Capital importation
A company investing or doing business in Nigeria may import capital for such purposes. The Nigerian Investment Promotion Commission (NIPC) Act\(^{67}\) and the Foreign Exchange (Monitoring and Miscellaneous Provisions) (FOREX) Act\(^{68}\) 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.

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64 Cap C20, LFN 2004.
65 Section 54(1), CAMA.
67 Sections 20, 21, and 24, NIPC Act.
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:

- Nigerian independent operators shall be given first consideration in the award of licences in all projects for which contracts are to be awarded;69
- 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;70
- 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;71
- operators are required to submit a Nigerian content plan demonstrating compliance with the requirements of the Act;72 and
- entities operating within the industry are to retain the services of Nigerian legal practitioners or a firm of practitioners with offices in Nigeria.73

iii Anti-corruption
Efforts to curb corruption in the Nigerian oil and gas industry led to the establishment of the Nigerian Extractive Industries Transparency Initiative (NEITI) in 2004. NEITI, under its enabling law74 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.

IX CURRENT DEVELOPMENTS
Presently, the Nigerian government has also indicated that it would be putting out a comprehensive set of policies covering the oil and gas industry. Accordingly, a national

69 Section 3(1), Local Content Act.
70 Section 3(3) ibid.
71 Section 10(1), ibid.
72 Section 7, ibid.
73 Section 51(1), ibid.
74 The NEITI Act 2007.
oil policy, national gas policy and a fiscal policy, which are expected to underpin the legal framework, have been drafted and are being made available to stakeholders and the public for consultation.

As indicated in the introductory section of this chapter, it appears the present administration intends to split the PIB into three separate bills to address the industry reform, fiscal framework and revenue management of the oil and gas industry. Unfortunately, detailed information on this shift from enacting a single piece of legislation cannot be provided at this point as deliberations on the elements of these legislations and in fact the actual number of fragments that will emanate from the PIB are yet to be finalised. Sterling Partnership is part of the technical work group set up for this effort and will provide update on developments once information is available to the general public.

With regard to petroleum refining, the federal government has awarded licences to 24 Nigerian companies to construct and operate refineries (conventional and modular). Interestingly, work is still ongoing on Dangote’s refinery project, expected to commence commercial production by 2018. While the NNPC leadership is committed to revamping the existing government-owned refineries, it is expected that these refineries will soon be operating at full capacity.

There are many unfolding changes in policy flowing from the recent change in government in Nigeria. We anticipate that there will be more changes in due course. The information contained is correct at time of writing and further updates will be discussed in the next edition.
Chapter 20

NORTH DAKOTA

Kimberly A Backman

I INTRODUCTION

Oil was first discovered and produced in North Dakota in 1951, revealing a petroleum basin extending across several hundred thousand square miles from North Dakota to South Dakota, Montana and Canada, known as the Williston Basin. Since that time, oil production and development in North Dakota has been fairly continuous with the billionth barrel of oil being produced in October 1989. However, it has been the development of the Bakken petroleum system in the last decade that has propelled North Dakota to its position as the second largest oil-producing state in the United States.

Owing in large part to advances in drilling and recovery technology, including the use of horizontal drilling, oil production in North Dakota surpassed 1 million barrels of oil per day in June 2014. There are currently 13,239 active wells producing in North Dakota, with the majority, 11,129 wells, producing from the Bakken and Three Forks formations. Since the first well was drilled, more than 3 billion barrels of oil have been produced in

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1 Kimberly A Backman is an associate at Crowley Fleck PLLP.
2 North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, https://www.dmr.nd.gov/oilgas/.
4 North Dakota Industrial Commission, Department of Mineral Resources, Oil and Gas Division, https://www.dmr.nd.gov/oilgas/.
5 Id.
North Dakota. As of 2013, the United States Geological Survey estimated that the Bakken and Three Forks formations contain almost 7.4 billion barrels of undiscovered, technically recoverable, oil and 6.7 trillion cubic feet of associated natural gas.

Oil and gas resources in North Dakota are generally owned privately, but can also be owned by the State of North Dakota (State) or by the United States. Oil and gas production in North Dakota is regulated by the North Dakota Industrial Commission (NDIC) by administering the laws set forth in the North Dakota Century Code (NDCC) and the rules provided by the North Dakota Administrative Code (NDAC). With the majority of minerals being privately owned, permission to explore and produce oil and gas is granted by individual owners without government involvement.

II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation
The NDCC contains the currently effective laws of the state of North Dakota and provides the main legislation that governs oil and gas exploration and production in North Dakota. Title 38 of the NDCC deals with Mining and Gas and Oil Production; key provisions include:

- control of oil and gas resources;
- geophysical exploration requirements;
- oil and gas production damage compensation;
- subsurface exploration damages; and
- carbon dioxide underground storage.

In addition, the North Dakota Administrative Code provides the codification of all the rules of state administrative agencies. Those rules are derived from authority provided by the NDCC. The NDAC includes the rules for, among others, the North Dakota Department of Health (NDDOH) and the NDIC, the state agencies responsible for regulating environmental issues and oil and gas exploration and production, respectively. When drilling and producing from oil and gas resources that are owned privately or by the state, operators must comply with all applicable state regulations. In addition, when drilling and producing on land owned by the United States, operators must also comply with all applicable federal government regulations.

ii Regulation
Pursuant to Chapter 38-08 of the NDCC, North Dakota regulates oil and gas exploration and production through the North Dakota Industrial Commission, an administrative agency made up of the Governor, the Attorney General and the Agriculture Commissioner. The NDIC has broad jurisdiction over the drilling, producing and plugging of wells, the
restoration of production sites and all other operations required for the production of oil and gas. In addition, the NDIC has recently been granted authority to regulate the gathering of oil, gas and produced water.

North Dakota law requires any entity or person desiring to drill an oil or gas well to obtain a permit from the NDIC prior to commencing operations for the drilling of a well. The NDIC establishes ‘spacing units’ for the drilling of wells for each separate ‘pool’ or ‘common source of supply’. Spacing regulates the location and density of wells. In areas that are not spaced, ‘wildcat’ wells are required to be located in accordance with state-wide well location rules established by the regulations. After a wildcat well is completed as a producer, the NDIC holds an administrative hearing to establish ‘temporary spacing’ for the pool discovered by the wildcat well. A spacing unit is required to be such ‘as will result in the efficient and economical development of the pool as a whole’. Three years after temporary spacing has been established, another hearing is held to establish ‘proper spacing’ for the pool. When necessary to prevent waste, protect correlative rights, or prevent the drilling of unnecessary wells, the NDIC may authorise additional wells to be drilled in a reasonably uniform plan in the pool or any zone thereof.

Spacing, however, does not provide a basis for the allocation of proceeds of production. Absent effective voluntary pooling of all oil and gas interests in the spacing unit, the NDIC is required to enter an order pooling, or integrating, all interests within a spacing unit if it has been established that there are separately owned tracts or interests within the spacing unit. Each owner of an oil and gas interest has the opportunity to participate in the risk and cost of drilling a well. Regulations establish the procedures for offering each owner the opportunity to participate in drilling the well. In the event any cost-bearing interest owner in a spacing unit elects not to participate in the risk and cost of drilling a well, the owners paying the costs of drilling are entitled by statute to recover a ‘non-consent penalty’ equal to (1) in the case of non-consenting mineral owners, 50 per cent of the proportionate share of the reasonable actual costs of drilling and completing the well, and (2) in the case of non-consenting leasehold owners, 200 per cent of the proportionate share of the reasonable actual costs of drilling and completing the well.

While pooling establishes a method of consolidating the interests in a spacing unit, North Dakota law also provides for compulsory unitisation, whereby all or a portion of a pool may be consolidated for the purpose of conducting enhanced recovery methods such as water injection or air injection, ‘or any other form of joint effort calculated to substantially

10 N.D. Cent. Code Section 38-08-04 (2014).
11 Id. Section 38-08-26.
12 Id. Section 38-08-05.
13 Id. Section 38-08-07.
15 Id.
16 N.D. Cent. Code Section 38-08-07(2) (2014).
20 N.D. Cent. Code Section 38-08-08 (2014).
21 Id.
increase the ultimate recovery of oil and gas’. In recent years, the NDIC has established several units in which production was predicted to be increased by efficient location of wells without regard to spacing unit setbacks that would otherwise be required.

Horizontal drilling was first utilised in North Dakota in 1987 and, in recent years, has become the primary method of developing ‘tight’ reservoirs such as the Bakken petroleum system. As the prevalence of such activity has increased, the NDIC has modified its standard procedures. Spacing units for vertical wells ranged from 40 acres for shallow wells to 640 acres for deep gas wells, with the vast majority of vertical spacing units consisting of 320 acres or less. However, the NDIC has recognised the necessity for larger spacing units to accommodate long laterals. The most prevalent spacing unit for Bakken horizontal wells is 1,280 acres, with a spacing unit consisting of two adjacent governmental sections. Spacing units of 2,560 acres are also routinely authorised; and, to accommodate unusual conditions such as drilling under lakes or rivers, the NDIC has established 3,840 acre and larger spacing units.

To maximise the recovery of hydrocarbons, the NDIC routinely authorises ‘infill’ or ‘increased density’ wells to be drilled, with orders frequently authorising 10 or more wells to be drilled on each spacing unit. The NDIC also routinely creates ‘overlapping’ spacing units in which two previously created units are combined to allow for one or more wells to be drilled on or near the common boundary of the two units.

### iii Treaties

The United States has tax treaties with numerous countries and is also a signatory to the New York Arbitration Convention, which deals with recognition and enforcement of foreign arbitral awards. However, treaties have little effect on oil and gas production in North Dakota. North Dakota is a member of the Interstate Oil and Gas Compact Commission, which is a multi-state government agency that promotes conservation and efficient recovery of domestic oil resources. Membership includes the governors of 30 oil and gas producing states. In addition, North Dakota has enacted the Multistate Tax Compact, one of the primary purposes of which is to facilitate proper determination of state and local tax liability of multi-state taxpayers and avoid duplicative taxation.

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22 Id. Sections 38-08-09.1 through 38-08-09.16.
24 See, particularly, North Dakota Industrial Commission Order Nos. 14496, 14497 and 14498, all dated 22 April 2010. For an example of a 3840-acre spacing unit, see North Dakota Industrial Commission Order No. 22420, dated 9 July 2013.
25 Id.
26 See, for example, North Dakota Industrial Commission Order No. 21151, dated 3 January 2013.
III LICENSING

The right to explore for and produce oil and gas in North Dakota is granted by each separate owner of an oil and gas interest by executing an oil and gas lease. Most minerals in North Dakota are privately owned, therefore, the right to explore for oil and gas is privately negotiated between the mineral owner and the potential lessee. Alternatively, as discussed in Section II, infra, an oil and gas owner has the option to participate in the risk and cost of drilling the well on terms it can negotiate with the producer.

As previously mentioned, the exception to private ownership of oil and gas is ownership by the state or the United States. Minerals owned by the state are under the control of the Board of University and School Lands and are managed by the Department of Trust Lands. State oil and gas leases are awarded by the Department of Trust Lands through a bidding process at quarterly public auctions. The Bureau of Land Management (BLM) is responsible for leasing federal oil and gas interests. Under federal law, all federal lands available for leasing are offered for bid at an oral auction.

Oil and gas leases are considered to be a conveyance from the lessor to the lessee; but, under North Dakota law, they are also considered to be a contract between the parties. As such, sufficient consideration is required for the lease to be effective. Historically, leases included delay rental provisions requiring that a rental be paid to the lessor each year of the primary term if production had not been established to maintain the lease. Today, however, most oil and gas leases are paid-up leases whereupon an up-front bonus payment is paid to the lessor prior to the execution of the lease. No further payments are generally required to maintain the lease during its primary term, unless production is established, whereupon royalty proceeds must be distributed to the owner.

The provisions included in an oil and gas lease are those that will allow the lessee to explore for oil and gas as well as maintain the lease as long as the leased land, or land pooled with the leased land, continues to produce oil or gas. To this end, a lease will include granting language giving the lessee the right to develop and produce oil and gas, or other listed substances, from the leased premises for a specified initial primary term. A typical primary term generally ranges from two to five years although state leases include a five-year primary term and federal leases include a 10-year primary term. Thereafter, the lease can be ‘held by production’ indefinitely.

A lease will also include the royalty rate or the percentage of production the oil and gas owner is entitled to receive. Early leases in North Dakota typically contained a royalty rate of one-eighth. Today, royalty rates tend to range between one-sixth and 20 per cent, but can be whatever percentage to which the oil and gas owner and lessee agree. Additionally, a typical lease will contain pooling provisions; a shut-in clause, which provides that a lease will be maintained if a well capable of producing gas, and sometimes oil, is shut in; and will provide whether or not the lease is assignable without consent. Any additional terms to be included in the lease can be negotiated between the oil and gas owner and the lessee.

An oil and gas lease will automatically expire if drilling operations for a well have not been commenced during the primary term of the lease. Unless the lease states otherwise,

31 43 C.F.R. Section 3120.1 (West).
should a well be drilled on any part of the leased lands during the primary term and production subsequently be obtained, the lease will be held by production and will continue to be a valid lease until production ceases on the leased lands. The lease will then expire once oil or gas is no longer produced from lands covered by the lease. State leases are unique in that they require actual production in commercial quantities to be established prior to the end of the primary term, not just the commencement of drilling operations, in order for the lease to be held by production.

In addition, under an oil and gas lease, there is an obligation to pay royalties to the oil and gas owner, and by statute, breach of this obligation may result in the cancellation of the lease should a court determine that the equities of the situation so require. If royalties are not paid within 150 days after oil or gas is marketed and the oil and gas owner does not seek to cancel the lease, the operator is required to pay interest on the unpaid royalties at a rate of 18 per cent per annum. However, should ownership of the oil and gas be in dispute or should an oil and gas owner be unlocatable, the provisions of this statute will not be applicable.

IV PRODUCTION RESTRICTIONS

North Dakota law authorises the NDIC to regulate the amount of production of oil and gas by setting ‘market proration’ orders. In the 1960s, the NDIC routinely issued state-wide proration orders that established marketing districts and limited state-wide production to the ‘market demand’ for both oil and gas. In the 1980s, the NDIC restricted production from several fields as a result of limited gas gathering and processing facilities, resulting in what was determined to be excessive flaring.

Spacing orders typically provided that wells were allowed to produce at an unrestricted rate for a limited period of time (e.g., 60 days) after completion of a well and then were restricted to 100 barrels of oil per day until the well was connected to a gas-gathering facility. However, the NDIC frequently extended the period of unlimited production for wells.

In 2014, the NDIC issued an order that established a system of ‘gas capture’ goals, ranging from 74 per cent on 1 October 2014 to 95 per cent by 1 October 2020. Each operator is required to meet the gas-capture goal in effect for any month, with compliance measured on a state-wide, county, field or individual well basis. In the event the gas capture goal is not met, production is restricted from any well that is not in compliance to either 100 or 200 barrels of oil per day, depending upon whether 60 per cent of the gas from the well in question is captured. The order includes provisions for crediting producers for ‘beneficial use’ of gas through electric generators, liquid stripping facilities or other value-added processes.

34 Id.
35 Id..
36 N.D. Cent. Code Section 38-08-06 (2014).
39 See, for example, North Dakota Industrial Commission Order No. 23959, dated 20 June 2014.
40 North Dakota Industrial Commission Order No. 24665, dated 1 July 2014.
Insofar as export restrictions are concerned, after a 40-year ban on exporting crude oil from the United States, the ban was lifted in December 2015. Previously, the export of domestic crude oil was generally prohibited unless a licence was obtained from the Department of Commerce. Pursuant to recent changes in federal law, a licence is no longer required to export crude oil. However, exports to embargoed or sanctioned countries or persons continues to require authorisation.

V ASSIGNMENTS OF INTERESTS

The process required for assigning ownership of an oil and gas lease is dependent upon whether the lease was executed by a private owner, the state or the United States. Approval is not required for the assignment of an oil and gas lease covering privately owned minerals, unless approval by the oil and gas owner is specifically required by the lease provisions or other agreement between the parties. In order for an assignment to be effective notice as to all third parties of the transfer of the interest, however, the assignment must be recorded in the recorder’s office of the county in which the lands covered by the lease are located.41

Transferring ownership of a state lease or federal lease, in whole or in part, requires approval. Assignment of a state lease is subject to written approval by the Commissioner of University and School Lands before the assignment becomes effective.42 Likewise, assignment of a lease executed by the United States is subject to approval by the BLM before the transfer of interests will be recognised.43 Assignments of state and federal leases are generally approved as long as the formalities for obtaining approval have been properly followed.

VI TAX

The provisions governing taxes applicable to oil and gas production are provided for in Chapter 57 of the NDCC. The oil and gas production tax provisions have recently been amended in order to implement a more stable and predictable oil tax scheme.

Previously, the law provided for a flat 5 per cent gross production tax levied on all oil and gas produced within North Dakota to be paid in lieu of other taxes, such as property taxes.44 The law further provided for an additional 6.5 per cent tax known as the oil extraction tax.45 It also included a small trigger tax break that reduced the oil extraction tax to 2 per cent and a large trigger tax break that waived the oil extraction tax for a period of two years.46 The tax breaks became effective upon oil prices falling below a certain amount as defined by statute and adjusted for inflation. However, the small trigger tax break expired June 2015 and the large trigger tax break expired 30 November 2015.47

45 Id. Section 57-51.1-02.
46 Id. Section 57-51.1-03.
47 Id. Section 57-51.1-03(9).
With the recent amendments to the tax provisions that became effective 1 January 2016, the maximum total tax rate on oil is 10 per cent to 11 per cent. The trigger tax breaks were eliminated and the 6.5 per cent oil extraction tax was reduced to 5 per cent. The 5 per cent gross production tax is still applicable, bringing the total effective tax rate to 10 per cent. The oil extraction tax will, however, increase to 6 per cent if the average price of a barrel of oil exceeds a trigger price of US$90 for any consecutive three-month period.

The North Dakota tax provisions provide for various exemptions from the oil extraction tax. They include: exemptions for stripper wells (a well drilled and completed whose average daily production of oil, during any preceding consecutive 12-month period, did not exceed 10 barrels per day for wells of a depth of 6,000 feet; 15 barrels per day for wells of a depth of more than 6,000 feet but not more than 10,000 feet; and 35 barrels per day for wells of a depth of more than 10,000 feet inside the Bakken and Three Forks formations); incremental production from secondary and tertiary recovery projects for a five-year period from the date incremental production begins; and the first 75,000 barrels of oil produced during the first 18 months after completion of a well drilled and completed outside the Bakken and Three Forks formations. The tax provisions further provide for an exemption to the gross production tax on shallow gas for a period of two years and 30 days if the gas is collected and used at the well site.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The protection of both human health and the environment in the United States are governed by various federal laws, including the Clean Air Act, the Clean Water Act, the Safe Drinking Water Act and the Resources Conservation and Recovery Act, each of which deal with air emission standards, surface water standards, underground water standards and waste management, respectively. Although the regulations contained in the federal environmental laws are not limited specifically to the oil and gas industry, most are applicable to various components of oil and gas exploration and production. The Environmental Protection Agency (EPA) is the primary federal agency charged with implementing and enforcing federal environmental laws.

When dealing specifically with North Dakota environmental issues, the NDDOH is the primary state agency charged with regulating air quality, water quality and waste management. This is done in conjunction with the federal regulations and requirements mentioned above. The NDDOH sets emissions standards as well as sets registration, reporting and permitting requirements in connection with oil and gas production facility emissions.

The Environmental Health Section of the NDDOH includes, among others, the Air Quality Division, Waste Management Division and Water Quality Division. The primary

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49 Id.
functions and responsibilities of each division include coordinating communications with the EPA regarding state programmes and related environmental issues and monitoring and enforcing compliance with state and federal environmental laws. 53

The Air Quality Division of the NDDOH administers and coordinates the air pollution control programme and specifically regulates emissions from oil and gas well production facilities to ensure that any operator of an oil or gas well production facility complies with the air quality standards as established by the NDDOH.54 The administrative rules established by the NDDOH work in conjunction with the rules and procedures established by the Federal Clean Air Act. Oil and gas production emission standards require that an operator of any oil or gas well submit a registration form as well as an analysis of any gas produced from the well to the NDDOH to ensure that the production facility is in compliance with emissions standards.55 Also, if any oil or gas well production facility is found to emit, or has the potential to emit, 250 tons per year or more of any air contaminant as determined by North Dakota law, the operator must comply with the specified permitting requirements to prevent deterioration of air quality.56 Further, the rules provide that emissions must be controlled through the use of flares, submerged fill pipes or tanks.

The Ground Water Division of the NDDOH administers an Underground Injection Control (UIC) programme as established under the Safe Drinking Water Act, to regulate the quality of underground sources of drinking water.57 Underground injection involves discharging fluids, often including water, wastewater or water mixed with chemicals, underground into porous rock formations. The purpose of the UIC programme is to ensure that wells are properly sited, constructed and operated so that underground injection is an environmentally safe method to dispose of wastes and contaminants and are not injected into underground water sources.58 Under the UIC standards, wells are divided into five classes for regulatory purposes. Wells that include injection of brines and other fluids associated with oil and gas production are known as Class II wells. While the NDDOH administers the UIC programme in North Dakota, Class II injection wells are regulated by the NDIC, the rules of which are provided for under Chapter 43-02-05 of the NDAC.

The NDDOH Division of Waste Management administers rules and permits related to solid waste management and hazardous waste management, including waste generated by oil and gas production. The NDDOH classifies types of waste and provides the required methods of disposal. In addition, North Dakota law requires that all waste material associated with oil and gas production be properly disposed of in an authorised facility according to applicable local, state and federal laws.59 Also, the NDIC regulates waste from crude oil that may be processed to recover further oil.60

55 Id. 33-15-20-02 (2015).
56 Id. 33-15-20-03.
57 Id. 33-25-01.
The process of abandoning a well is regulated by the NDIC, the framework of which is provided for in Chapter 43-02-03 of the NDAC. The process begins with the operator filing a notice of intention to plug the well with the NDIC. Once the operator receives approval from the NDIC, plugging operations may commence. The process of plugging a well requires that oil, gas and water will be permanently confined in the separate strata in which they were originally contained. Within a reasonable time after the well has been plugged, the site, access road and other associated facilities are required to be reclaimed as closely as practicable to the original condition with all equipment and debris removed and flow lines purged.

VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
A person engaged in geophysical exploration in North Dakota is deemed to be doing business in North Dakota and must be qualified to do business within the State prior to commencement of exploration. Various NDCC provisions, including the North Dakota Business Corporation Act, the Uniform Limited Liability Company Act and the Uniform Limited Partnership Act provide the general requirements for foreign entities to conduct business in North Dakota.

Under the North Dakota Business Corporation Act, a corporation incorporated under the laws of another state or foreign jurisdiction is considered to be a foreign corporation to North Dakota. In order for a foreign corporation to do business in North Dakota, it must file a foreign corporation certificate of authority application with the Secretary of State and provide a certificate of good standing from the state or country where the corporation is incorporated. Upon approval by the Secretary of State, the corporation will have authority to transact business in the State.

The same general requirements apply to limited liability companies, limited partnerships, limited liability partnerships and limited liability limited partnerships. The general procedure differs slightly depending on the type of entity; however, each statute requires that a foreign entity apply for a certificate of authority from the Secretary of State prior to conducting business in the state. Additionally, a foreign entity may not obtain a permit required by the state or utilise the court system until a certificate of authority has been approved by the Secretary of State. The provisions further require that the foreign entity maintain a registered agent in North Dakota.

A foreign entity with a valid certificate of authority has the same rights and privileges as a domestic entity. Generally, the laws of the foreign entity’s jurisdiction govern its internal activities. However, a certificate of authority does not authorise the foreign entity to exercise any powers that a domestic entity is unable to exercise.

ii Capital, labour and content restrictions
North Dakota law generally does not impose any hiring restrictions related specifically to oil and gas operations. However, oil and gas operators, as with all employers, are required to follow federal law when hiring non-US citizens. The Immigration and Nationality Act (INA)
requires that employers verify the employment eligibility of any person being hired to work in the United States, including US citizens and foreign workers. The INA also provides the conditions for temporary and permanent employment of non-US citizens.

Numerous federal agencies are involved in the process of granting permission for foreign workers to work in the United States, including the Department of State, the Department of Labor and US Citizenship and Immigration Services (USCIS). Permission is granted through the use of various employment-based visas. Employment-based visas are divided into several categories and the agencies involved and the procedure that must be followed depend largely on the type of visa for which the employer is applying.62 Regardless of the type of visa requested, generally, the employer must petition the USCIS for the visa on behalf of the foreign worker.

Insofar as foreign investment is concerned, USCIS administers the EB-5 Immigrant Investor Program which allows entrepreneurs who invest US$1 million, or at least US$500,000 in a targeted employment area, in a commercial enterprise in the United States and plans to create 10 full-time jobs for qualified US workers to apply for permanent residence.63

iii Anti-corruption

North Dakota law does not provide for laws regarding anti-corruption as related specifically to oil and gas production; however, the NDCC does provide provisions that make it unlawful to bribe public servants,64 lobby through unlawful means65 and engage in corrupt practices related to political purposes.66

IX CURRENT DEVELOPMENTS

The dramatic increase in horizontal development of the Bakken petroleum system has brought a number of challenges to the oil and gas industry and regulators in North Dakota in recent years. As discussed in Section IV, infra, the NDIC has actively imposed production restrictions to reduce flaring. Limited take-away capacity of pipelines has led to a rapid expansion of rail transportation of crude oil, with several highly publicised incidents in which trains hauling relatively high-gravity Bakken crude have had dramatic derailments. In an attempt to reduce the potential for explosions and fires, in 2014, the NDIC also entered an order that requires crude oil produced from the Bakken to be ‘conditioned’ through the operation of heater/treaters at established pressures and temperatures or, alternatively, to be tested to meet a vapour pressure of 13.7psi or less.67

62 See www.uscis.gov/working-united-states/working-us for a complete list of employment-based visas.
63 Immigration and Nationality Act Section 203(b)(5) (2013).
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 other smaller fields. The Norwegian government has over the past 10 to 15 years introduced various adjustments in the legal (including fiscal) regime to attract new players to the NCS, and today about 50 foreign and Norwegian companies are active on the NCS.

At the end of 2015, 82 fields were in production while nine fields were under development on the NCS. In 2015 said fields produced almost 2 million barrels of oil per day (which includes crude oil, natural gas liquids (NGL) and other liquids), and approximately 115 billion standard cubic metres of gas (40MJ). In 2015, Norway had a marketable petroleum production totalling 227.8 billion standard cubic metres of oil equivalent.

Ten fields are now under development on the NCS, of which seven are located in the North Sea, while the other three are located in the Norwegian Sea and the Barents Sea respectively.

The oil and gas sector is Norway’s largest measured in terms of value added, government revenues, investment and export value. In 2015, the Norwegian government’s total net cash flow from petroleum activities was 218 billion kroner, and the petroleum sector accounted for approximately 25 per cent of the state’s total revenue. The state’s income from the petroleum sector is transferred to a separate fund; the Government Pension Fund – Global. By September 2016 the fund was valued at approximately 7,400 billion kroner.

After more than 40 years of production on the NCS, it is estimated that between 55 and 60 per cent of the expected recoverable resources still remain in the ground (Jan Mayen and the previously disputed area in the Barents Sea south-east excluded).

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The Barents Sea south-east has, following the delimitation agreement entered into between Norway and Russia effective 7 July 2011, been opened for petroleum activities. The very first licences in this area were awarded by the Norwegian government in the 23rd licensing round 18 May 2016, see more details in Section IX, infra.2

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, infra.

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).

i 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.

2 Source: the Norwegian Petroleum Directorate.
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 Norwegian Petroleum Directorate’s (NPD) 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 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, the Ministry of Environment, and the Ministry of Fisheries and Coastal Affairs.

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 Norwegian continental shelf 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 the Environment, is responsible for all environmental issues pertaining to the petroleum activities, such as granting the requested permissions to pollute.

Finally, the Norwegian Coastal Administration, under the Ministry of Transport and Communications, is responsible for the state's oil spill preparedness.

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, entered into between Norway and several foreign states. The double taxation treaties 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 double tax treaties 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, infra.

Licences can also be obtained through transfer of assets. 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 due 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 40 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 gas sales as the actual sales prices are used.
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. 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 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 a resolution to the parliament issued in October 2009 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.

It is not possible to provide an exact estimate of the time frame for obtaining approval from the MPE, as it may vary from a few 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.

VI  TAX

Petroleum activities on the NCS are governed by the Petroleum Taxation Act. The Act levies a special tax of 53 per cent in addition to the ordinary corporate tax rate of 25 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 5.5 per cent per year over a four-year period on capital investments, in total 22 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 having 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 indefinite in time.

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.

Due 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 2016 is 1.02 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 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:

- the Framework Regulations of 12 February 2010 No. 158;
- the Management Regulations of 29 April 2010 No. 611;
- the Facilities Regulations of 29 April 2010 No. 634;
- the Activities Regulations of 29 April 2010 No. 613; and
- the Technical and Operational Regulations of 29 April 2010 No. 612.

As a general rule all mobile offshore 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 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). 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 case he or she is 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.

### Anti-corruption

Corruption in general is criminalised in the Norwegian Penal Code, Section 276a–c 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. Said regulation
Norway

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 ten different production licenses consisting of 40 prospective blocks.

The Norwegian government is keeping up its phase on new acreage awards in frontier areas, and announced in the end of August 2016 that companies were invited to nominate blocks for the 24th licensing round. Nominations are welcomed in all opened areas of the North Sea and the Barents Sea that are not already covered by annual awards in pre-defined areas (APA) rounds. The MPE expect to officially announce the specific areas offered for application by mid-2017, which normally imply that licences could be awarded before the end of 2018.

Fifty-six exploration wells were spudded on the Norwegian continental shelf and 16 discoveries made during 2015. The resource growth from these discoveries is about 30 million standard cubic metres of oil equivalents. Most of the new discoveries are small and near existing or planned infrastructure, which in turn will imply that the development costs are much lower compared to standalone developments.3

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. 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 Gassled 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 with both regulations is to ensure efficient use of existing infrastructure on the NCS, and the overriding principle is that the owner only shall be entitled to maximise his or her 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.

One of the major field developments recently completed is the Goliat field. This is the first oil discovery developed in the Barents Sea. After several postponements, the operator Eni Norge announced that the field started production on the 12 March 2016. The production is 100,000 barrels per day, and the field is expected to produce for at least 15 years. The field is located 50 kilometres southeast of the Snøhvit field and barely 50 kilometres from the coast.

Several major oil discoveries are planned for development and overall there has been an increase in recent development projects. The development of the Statoil-operated Johan Sverdrup field stands out as the project people in the industry are most enthusiastic about. The Plan for Development and Operation (PDO) was approved by the MPE in August 2015.

3 Source: Norwegian Petroleum.
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. Production is initially planned to start by the end of 2019, and 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 expected 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.

Despite Norway’s ongoing world-leading development projects, yearly production has decreased steadily over the past 10 years. This is partly explained by an increasing number of fields reaching the end of their lifetime without new fields fully replacing production from the fields that have ceased production. In addition, oil prices have remained at low levels since the significant drop in the autumn of 2014.

Affected businesses have experienced severe reductions in revenue over a short period of time. This has led to the whole oil and gas industry implementing massive cost-cutting measures. Several Norwegian projects have been completed at up to 50 per cent lower costs than what was the case just a few years ago. As an example, the original development costs for Johan Castberg were estimated to be 100 billion kroner, while the latest estimate is between 50–60 billion kroner. This cost improvement reduces the breakeven price from US$80 to below US$45 per barrel.

Before the sharp fall in oil prices it was normal to exercise options to prolong rig contracts and contracts with offshore vessel, but this is no longer the case. This has created overcapacity in the market, inter alia, with regard to drilling rigs, supply vessels, seismic vessels etc.

The current reduction in E&P investments and activities on the NCS have led to many offshore projects being delayed and new projects being put on hold. Nearly 40,000 jobs in the Norwegian offshore sector have disappeared, out of about 250,000 nationwide.

Despite the rather gloomy short-term market outlook, it is hoped that major new field developments, 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.
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, the petroleum potential of the country – 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 new legislation continued to follow the concession model, but instituted more flexible terms for the basic framework of contracts. For instance:

\[ a \] 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

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1 Rui Mayer and Diogo Ortigão Ramos are partners, Ana Isabel Marques is a senior associate and Berta de March is an associate at Cuatrecasas, Gonçalves Pereira.

minimum exploration commitment requirements are of one well per block from the fourth year, with the rest being left for agreement in negotiations.

Deep offshore areas will not be subject to these terms until a specific regulation is published (which is not expected anytime soon), an incentive to attract companies interested in exploring these areas, which will enjoy even greater flexibility when submitting their proposals.

Shortly after the 1994 law was enacted, and to prepare for a public tender for the award of exploration and production rights, the authorities contracted TGS-NOPEC to conduct a seismic and gravimetric study of the deep offshore areas, which only then became available to exploration thanks to technological advances. The tender was organised in 2002, leading to the award, in 2005, of one concession covering two deep offshore blocks. Later, new rights were awarded following direct negotiations with several companies that approached the authorities. Onshore, one company has been active since 2001, having registered ‘strong indications’ of gas in two wells in the Alcobaça region. Oil shows have also been registered, although production tests were inconclusive.

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.3

The government is still keen to attract new investment in oil exploration but, understandably, does not consider the sector a major priority for public policy and spending. The authorities’ attitude has been relatively passive, responding to the initiative of interested companies rather than embarking on promotion. 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.

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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. However, the new text of the law allocates to the ENMC new responsibilities concerning:

1. the supervision and monitoring of the markets for crude oil, petroleum products, piped liquefied petroleum gas (LPG), biofuels, promotion of technical safety and fuel quality;
2. the supervision of exploration, development and exploitation of oil resources;
3. the monitoring of the evolution of the internal energy market and other regional markets; and
4. its participation in defining policies for the promotion of biofuels and other renewable fuels and consumer protection.

Owing to these new duties, the following areas of competence previously corresponding to the Energy and Geology General Directorate (DGEG) were transferred to the ENMC:

- monitoring the markets of crude oil and petroleum products;
- registering traders of oil products;
- monitoring refining, storage, transportation, distribution and marketing of petroleum products;
- monitoring storage, distribution and marketing of piped LPG;
- regulating third-party access to petroleum products and piped LPG storage, transportation and distribution facilities;
- supervising the quality of the fuel provided for consumption purposes and for promotion of technical safety;
- handling complaints related to activities of the value chain of the oil products and piped liquefied propane gas;
- analysing and assessing the causes of accidents involving the use of fuels; and
- creating an updated document and database concerning the main characteristics and development perspectives of the national oil system.

As mentioned above, 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 DGEG regarding the preparation of laws and regulations, and on drafting relevant statistical information.
II LEGAL AND REGULATORY FRAMEWORK

i Domestic oil and gas legislation

Oil and gas exploration and production activities are regulated by Decree-Law No. 109/94, published on 26 April 1994 (the Decree-Law). The following documents were published to complement its provisions:

a Notice dated 21 July 1994, identifying the areas where oil exploration, development and production operations are permitted, amended by the notice dated 12 March 2002.

b Dispatch No. 82/94, establishing the fees chargeable by the competent authorities for the issuance of preliminary evaluation licences and for the signature of concession agreements and assignment agreements.

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

d Ministerial Order No. 79/94, published on 26 July 1994, establishing the basis of the concession agreements referred to in Article 83 of the Decree-Law.

These legal documents aim to clarify and simplify the rules and procedures governing oil and gas exploration and production, including the award of rights, and thus attract new investment to these activities.

The relevant contents of some major provisions of these legal documents are summarised below.\(^5\)

Property of mineral resources

Any underground mineral resources in the areas subject to the sovereignty or dominance of Portugal are an integral part of the state’s public domain. Oil and gas exploration and production activities can only be performed under concessions granting exclusive rights without prejudice to any third parties, to other activities or resources, or to national interests in national defence, the environment, navigation and scientific investigation, and management 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.

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 ministers.

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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/.

\(^5\) For further details, see Section III, *infra*. 
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 well-bore 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 ENMC’s prior authorisation.


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

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.6 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 nearly 50 countries, and has signed treaties to avoid double taxation with 76 countries based on the OECD model.

III LICENSING

Concession agreements that comply with the Decree-Law are the means of granting oil and gas exploration and production rights. The key terms of concession agreements are described below:

a Concession area: A single concession area may comprise up to 16 contiguous lots, arranged in one or more blocks.

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 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

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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, Kuwait, Latvia, Libya, Lithuania, Macau, Mauritius, Mexico, Morocco, Mozambique, Pakistan, Paraguay, Peru, Philippines, Poland, Qatar, Romania, Russia, São Tomé and Príncipe, Slovakia, Slovenia, South Korea, Tunisia, Turkey, Ukraine, Uruguay, Uzbekistan, Venezuela and Zimbabwe.

8 Sixty-seven are already in force and nine are signed, but still pending an exchange of notices to come into force. See http://info.portaldasfinancas.gov.pt/NR/rdonlyres/12EA70BF-1D5D-42BB-BF0B-A2E8B608367F/0/Table_of_DTCs_2016.pdf.


10 For deep offshore areas, these limits may be exceeded.

11 For deep offshore areas, the duration limit may be exceeded.
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.

Contractors: The concessionaire can use contractors to perform any activities or operations. The concessionaire must give prior notice to the ENMC of any contracts it intends to enter into for these purposes, and inform of the scope, duration, identity of the contractor and of the persons in charge of supervising these operations and activities.

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.

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.

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.

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.

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.

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For deep offshore areas, the area to be relinquished may be smaller.

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.
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.

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.

Environmental protection: The concessionaire must adopt all necessary measures and precautions to minimise the environmental impact of its activities, and must timely submit to ENMC its environmental protection plans 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\(^{14}\) 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:\(^{15}\)

<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.\(^{16}\) The following tax rules shall also be considered:\(^{17}\)

\(a\) 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);

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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;
- Taxable profits in excess of €35 million = 7 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.
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.

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

Under 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), 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. The environmental impact assessment is, therefore, a preventive method to foresee, estimate and reduce negative impacts and introduce possible alternatives, based on studies and data gathering. 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.

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, supra), 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 following receipt of the concessionaire's request. If the minister's decision is not communicated within 90 days following 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);\(^{18}\)
d. the incorporation agreement and articles of association (having certified the powers of attorney of the representatives and their signatures) are executed by the foreign company’s designated representatives;
e. the company is registered with the commercial registry office;
f. the incorporating documents are published online;
g. the start-up is notified to the tax authorities;

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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 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 pre-written bylaw 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.

iii Anti-corruption
In general, Portugal applies the same measures to prevent active and passive corruption as are applied in the other EU Member States, namely those prescribed in Directive 2003/568/JHA, issued on 22 July 2003 by the European Council, which calls on Member States to criminalise acts of active and passive corruption and to adopt the necessary measures to ensure the criminal liability of legal entities for such acts.

Under Portuguese criminal legal provisions, organisations can be held criminally liable for crimes of corruption when improper tangible or intangible advantages are promised or
given by a person that occupies a management position or is acting with delegated authority. The Portuguese Penal Code provides that legal entities are exempt from criminal liability for acts of corruption committed within the organisation if the perpetrator acted against express orders or instructions from management.

IX CURRENT DEVELOPMENTS

In recent months, there was a public debate about possible environmental consequences of oil and gas exploration operations, and members of the parliamentary coalition that supports the current government 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.

An exploration well that was planned for the Offshore Alentejo Basin in the summer of 2016 was postponed to 2017 because the procedure for securing the necessary environmental licences took longer than anticipated, which meant that the meteorological window was lost. Another well that was planned for the area offshore on the southern coast of the Algarve for October was also postponed with no new date scheduled.
Chapter 23

RUSSIA

Natalya Morozova and Rob Patterson

I INTRODUCTION

With proven oil reserves of more than 102 billion barrels and natural gas reserves of over 32 trillion cubic metres (according to BP’s Statistical Review of World Energy 2016), Russia is a major global producer, supplier and consumer of oil and gas. In 2015, Russia was the largest exporter of natural gas by pipeline, and its production and export of oil have been steadily increasing since 2010. It has recently tripled its share of total global exports of LNG. Russia’s economy is heavily reliant on revenues derived from its oil and natural gas exports. 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 both offshore and of unconventional resources, as well as on exploration in the Far East. The worsening geopolitical situation in 2014 and 2015 and the Ukraine-related sanctions that are targeted specifically at the ability of Russian oil and gas companies to access external financing and certain technologies, may have an impact on Russia’s ability to maintain growth in production levels in the years ahead.

Historically, the EU has been the main market for Russian hydrocarbons. The Energy Strategy to 2030, which was approved in 2009, provides for the diversification of its export markets away from the core European market to prospective eastern markets and the growth of oil production and energy infrastructure in East Siberia and the Far East. This is likely to affect the legal environment for the industry. It had been hoped by the Russian government that the oil and gas sector would become the main driver of the country’s economic innovative growth. In particular, a developing Russia–China cooperation in the energy area, the Yamal LNG project and Gazprom’s long-term natural gas supply agreement with China (and the associated construction of the Power of Siberia gas pipeline) play a very important role in ensuring Russia’s economic security.

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Russia’s revenues have been adversely affected by the significant drop of oil prices in 2015–2016. However, the oil and gas industry in Russia has largely remained stable.

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 still remain in a state of development.

i Domestic oil and gas legislation

The legal framework of the oil and gas legislation in the Russian Federation revolves around the following laws:

- The Federal Law on Subsoil (the Subsoil Law). This is the core law governing a vast range of rules covering the allocation and development of natural resources.
- The Federal Law on Gas Supply in the Russian Federation (the Gas Supply Law). This law primarily governs natural gas development, transportation and sales.
- The Federal Law on Natural Monopolies. This law in part governs transportation of oil and gas via trunk pipelines.
- 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.
- The Federal Law on Production Sharing Agreements. This sets forth the regime for the development of natural resources via production sharing agreements.

The following federal laws are also relevant to the legal framework of the natural resources industry of the Russian Federation:

- The Federal Law on Environmental Protection.
- The Federal Law on Internal Waters, Territorial Sea and Contiguous Zone.

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:

- creation of an innovative and efficient energy sector;
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.

In December 2012, the government approved the State Programme for the Protection of the Environment for 2012–2020. The main objective of the programme is to improve ecological safety and preserve natural ecosystems in Russia.

In February 2013, the President signed into law the ambitious Strategic Programme for the Development of the Arctic up to 2020. The main objective of the programme is to explore the Arctic shelf, prepare its oil and gas resources for exploration, and form an Arctic reserve fund.

In December 2013, the government approved the Federal Programme of Economic and Social Development of the Far East and Baykal Region until 2018.

**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. From 2014, the Ministry will determine the procedure for setting regular payments for the use of subsoil.

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 such 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 develop 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 on 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.
Russia

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 licensing agreement, which is a constituent part of a subsoil licence. Breach of the licensing agreement by the subsoil user may result in termination or suspension of the licence.

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 only a few operational production sharing agreements now 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 the Russian Federation and the region 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 and/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 harsh 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, such as to reach and maintain certain agreed volumes of production. Production of resources above such volumes is prohibited.

The right to use subsoil can be restricted, suspended or terminated in a number of cases and, in particular, if:

- there is a direct threat to the life or health of people working or living in the area affected by the subsoil use;
- the licence holder has breached material terms of the licence;
- the licence holder systematically violates the subsoil use procedures;
- an emergency occurs (natural disaster, military action, etc.);
- the licence holder’s production does not reach the volumes required by the terms of the licence;
- the licence holder has been liquidated;
- the licence holder requests suspension or termination; or
- 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. There are often conflicts between Gazprom and other gas producers (especially, Rosneft) in relation to access to the UGSS.

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. At present, there is an overproduction of natural gas. The government has recently focused on development of a natural gas spot 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 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 specific tax payable by extractors of natural resources in Russia is the 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 a 20 per cent rate. It applies to all taxpayers in the Russian Federation. Of the 20 per cent rate, 2 per cent is payable to the federal treasury and 18 per cent is payable to the treasury of the relevant member region. Member regions 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. The
period of implementation of the tax manoeuvre is 2015–2017. The aim of the reform is broadly to shift the fiscal burden from the export of oil and oil products to its production through reduction of export duties and increase of the mineral extraction tax.

According to the report of the Russian Federal Customs Service, in 2015, receipts from exports of crude oil and oil products dropped by approximately 42 per cent, although the volume of exports of crude oil increased by 9.4 per cent and of oil products by 4 per cent. Receipts from exported goods were US$345.9 billion. Of this amount, approximately US$200 billion was attributed to the exports of hydrocarbons and products.

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:

- 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;
- recultivate the land and return it to a condition adequate for future use; and
- 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 wholly owned subsidiary or create a joint venture with Russian partners.
According to the Civil Code of the Russian Federation (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) is 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, labour and content 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) opening of ‘transaction passports’ with servicing banks in relation to transactions exceeding US$50,000 or equivalent, and certain others. 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 the Russian Federation 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 only criteria that must be complied with in order to use such regime is to pay foreign employees no less than 167,000 roubles per each calendar month in Russia and to provide evidence of such payment to the Russian authorities.

Some natural resources deposits (‘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 such 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, such acquirers are generally prohibited to acquire 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 the Russian Federation. 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 of the Russian Federation 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 the Russian Federation. 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 of the Russian Federation 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.

### 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 and CNPC) and Rosneft, without restricting Gazprom’s monopoly to supply natural gas through pipelines to external markets. Other gas producers in Russia, in particular Rosneft, continue to seek further restrictions on that monopoly.

In 2015, according to the Deputy Prime Minister, there were no political obstacles to offering controlling interests in Russian strategic companies to Chinese state-owned oil and gas companies.

However, there have been fundamental legal obstacles to foreign state-controlled companies (which would primarily include most likely candidates for investment from China or India) acquiring control in Russian strategic upstream companies, as the Strategic Law absolutely prohibits such investment.

The Russian government has found a way around the prohibition. The first known example of this is the Yamal LNG project in the Russian Arctic. In 2014, the China National Petroleum Corporation (CNPC) acquired a 20 per cent interest in the project. Simultaneously with this acquisition, the Chinese and the Russian governments signed a treaty for cooperation in the development of the Yamal LNG project. In late December 2015, the Russian government approved the protocol to the above treaty, which provides, inter alia, that the Chinese Silk Road Fund will acquire a 9.9 per cent interest in the Yamal LNG project. The acquisition was closed in March 2016 bringing the total foreign state-controlled investment in the Russian strategic company to a 29.9 per cent level which is prohibited by the Strategic Law. However, according to the Russian Constitution, international treaties supersede national laws. Since the protocol was ratified by the State Duma (the highest legislative authority), it became an international treaty of Russia that supersedes the Strategic Law to the extent the protocol allows a higher threshold as opposed to the Strategic Law. Obviously, the same legal mechanism can be used in other potential projects to overcome the Strategic Law prohibitions.
I INTRODUCTION

South Africa historically has been a mining jurisdiction with petroleum activity in the South African economy generally confined to exploration and downstream refining and liquid fuels distribution. Indeed, South Africa has limited oil reserves of just 20 million barrels and proven gas reserves of approximately 0.53 trillion cubic feet.1 This has the potential to change drastically. With the discovery of potentially large-scale onshore unconventional gas reserves and the expectations of substantial near term offshore crude oil and gas discoveries off the back of historic finds in neighbouring waters, South Africa is poised to transform into a petroleum jurisdiction.

Estimated technically recoverable resources in the Karoo shale gas fields alone are estimated to be as great as 390 trillion cubic feet.2 South Africa’s Minister of Mineral Resources (the Minister) has given the go-ahead for shale gas exploration in the Karoo that may enable these initial assessments to be more fully developed.3 In addition, substantial potential coal bed methane resources are in the process of being brought towards commercial development. Offshore potential, particularly in deep water, can clearly be seen by the substantial increase in farm-in and exploration activity. Some of the largest petroleum companies in the world

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1 Manus Booysen, Jonathan Veeran and Garyn Rapson are partners, John Smelcer and Keith Veitch are directors, and Benjamin Cronin is a senior associate at Webber Wentzel in alliance with Linklaters.
3 Ibid 1EIA.
have recently farmed into South African exploration blocks and are leading these exploration initiatives, including ExxonMobil, Shell, Total and Anadarko, among others. Underpinning these moves is the expectation of significant offshore resources based on the contiguousness of the geology with the game-changing recent finds in East Africa for South Africa’s east coast and Angola, Namibia and the Falkland Islands for South Africa’s west coast. This is coupled with the fact that there has historically been limited deepwater exploration offshore of South Africa.

Oil and gas is set to play a substantially expanding role in South Africa’s energy mix. This change presents substantial investment opportunities across the value chain, including in the upstream, for oil and gas investors in South Africa.

To foster and enable this investment and the development of the oil and gas industry, South Africa’s government has embarked on a series of legislative and regulatory amendments and changes in recent years, including:

- the passing of the Mineral and Petroleum Resources Amendment Bill No. B15B-2013 (the Bill), which seeks to amend the Mineral and Petroleum Resources Development Act 2002 (MPRDA), as amended by the Mineral and Petroleum Resources Development Amendment Act 2008 (the Amendment Act);
- the deliberations of an inter-ministerial committee tasked with addressing the concerns regarding certain provisions of the Bill;
- lifting the moratorium on hydraulic fracturing and drilling in the Karoo shale gas area;
- promulgating proposed hydraulic fracturing detailed regulations to govern drilling and exploitation of unconventional gas resources in South Africa;\(^5\)
- publishing the proposed declaration of the exploration for and or production of onshore unconventional oil or gas resources and any activities incidental thereto including but not limited to hydraulic fracturing as a controlled activity under the National Water Act 1998 (NWA).\(^6\) Undertaking a controlled activity requires authorisation under the NWA; and
- announcing the go-ahead for shale gas exploration in the Karoo.

This chapter presents an overview of the current upstream oil and gas legislative and regulatory regime in South Africa, as well as these proposed changes.

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II LEGAL AND REGULATORY FRAMEWORK

i Domestic upstream oil and gas legislation

**MPRDA**
The South African petroleum industry is primarily regulated under the MPRDA. Chapter 6 of the MPRDA governs the granting of exploration and production rights, and the issuing of technical cooperation and reconnaissance permits.

**DMR**
The Department of Mineral Resources (DMR) is responsible for the administration of the MPRDA, and is the national department of the government of South Africa accountable for overseeing the mining and petroleum industries of South Africa. The Minister is the political head of the DMR.

The designated agency: PASA
Under the MPRDA, the Minister may designate authority to an organ of the state or a wholly owned and controlled agency or company to perform any of his or her functions under Chapter 6 of the MPRDA (Petroleum Exploration and Production). The then-Minister of Minerals and Energy designated the Petroleum Agency of South Africa (PASA) to perform the functions set out in Chapter 6 of the MPRDA and such other functions as the Minister may determine from time to time.

ii Regulation
Applications for rights and permits under Chapter 6 must be lodged at the office of the PASA; in the prescribed manner; and with the prescribed fee. The PASA must accept an application within 14 days of receipt, if the above requirements are met; no other person holds a technical cooperation permit, exploration right or production right for petroleum over any part of the area applied for; and no prior application for the aforementioned has been accepted.

If the application does not comply with the above requirements, PASA must, within 14 days notify the applicant, in writing with reasons. The acceptance of an application prompts the commencement of the environmental impact assessment process pursuant to an application for an environmental authorisation, and related public consultation process required for the environmental authorisation application. Historically this process was...

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7 The following amendments to the MPRDA by the Amendment Act did not come in force on 7 June 2013: Sections (i) 11(1); (ii) 11(5); (iii) 38B; (iv) 47(1)(c); (v) 102(2); (vi) Section 106(2), and all the Sections listed in Section 94(2) of the Amendment Act, which were said to come into force simultaneously with Section 14(2) of the National Environmental Management Amendment Act, 62 of 2008 (the 2008 NEM Amendment Act).

8 Section 69 of the MPRDA.


10 Section 70 of the MPRDA.

11 For example, see application for a production right in section 83(1) of the MPRDA which is used to describe this section.
regulated under the MPRDA. However, the South African government recently implemented the ‘One Environmental System’, which has shifted this regulation to the National Environmental Management Act 1998 (NEMA) which governs the process of applying for an obtaining an environmental authorisation for the operation. The DMR remains the competent authority, having now been given authority to enforce these environmental laws in respect of activities conducted on or related to exploration and production areas. The ‘One Environmental System’, which was practically implemented on 8 December 2014, seeks to reduce the regulatory complexity of the petroleum industry (see further discussion below).

iii General issues

The Minister may, by notice in the government gazette, invite applications for exploration and production rights in respect of any block(s), and may specify a deadline or terms and conditions under which the application must be lodged and the terms and conditions subject to which such rights may be granted. Other applications may be directly received by PASA.12

Holders of rights granted under the MPRDA and registered with the Mineral and Petroleum Titles Registration Office (MPTRO) enjoy certain rights, including the right to enter the land to which such right relates; to bring onto that land any plant, machinery or equipment and build, construct or lay down infrastructure required for exploration or production; to explore for, or produce, the petroleum for which such right has been granted; to remove and dispose of petroleum found during the course of exploration or production; subject to the NWA, to use water for exploration or production; and to carry out other incidental activities that do not contravene the MPRDA.13

The Minister may cancel or suspend any reconnaissance permit, technical cooperation permit, exploration right or production right, after written notice, in accordance with the procedure outlined in Section 47 of the MPRDA, if the holder, among other things, contravenes the MPRDA; or breaches material terms or conditions of the right, which includes a contravention of any condition in the environmental authorisation granted for the operation.

The holder of any permit or right must submit such information, data, reports and interpretations to the designated agency as may be prescribed.14 PASA must submit progress reports and information within 30 days to the Council for Geoscience.15 Subject to the Promotion of Access of Information Act 2000, all information and interpretations thereof submitted to the PASA must be kept confidential for a period not exceeding four years, or until the permit or rights to which such information and interpretations relate terminate.16

Neither the state nor any of its employees is liable for the bona fide or inadvertent release of information submitted; or guarantees the accuracy or completeness of such information.17

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12 Section 73 of the MPRDA.
13 Section 5(3) of the MPRDA.
14 Section 88(1) of the MPRDA.
15 Section 88(1A) of the MPRDA.
16 Section 88(2) of the MPRDA.
17 Section 88(3) of the MPRDA.
As of 1 June 2013, South Africa has concluded 47 bilateral investment treaties (BITs), of which 23 are in force. While the scope and specificity of such clauses will vary, generally most BITs contain provisions regulating general standards of treatment, which apply to investments in general and, specific standards required in relation to any particular issue; and protection against expropriation, nationalisation and, increasingly, indirect expropriation.

According to the South African Department of Trade and Industry, (DTI), BITs allowed the legal and business community to challenge regulatory changes, which the government considered to be in the public interest. The DTI accordingly recommended the restructuring of South Africa’s BITs to ensure that the treaties align with South Africa’s broader social and economic priorities. In light of this, the Promotion and Protection of Investment Act (the Investment Act), was passed by Parliament in 2015 and assented to by the President on 15 December 2015. It has yet to come into effect.

There are various arbitration institutions and rules available to parties involved in BIT-related disputes, including the International Centre for Settlement of Investment Disputes (ICSID), the International Chamber of Commerce (ICC), and the rules of United Nations Commission on International Trade Law (UNCITRAL). South Africa is also a signatory to the 1958 Convention on the Recognition and Enforcement of Foreign

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On 7 September 2012, South Africa gave notice to terminate its BIT with the Kingdom of Belgium and the Grand Duchy of Luxembourg BIT. Termination notices have also recently been served on the Kingdom of Spain on 23 June 2013 and the Kingdom of the Netherlands on or about 21 October 2013. Most recently, on 28 October 2013, it was announced that South Africa had also served a cancellation notice one of its single biggest investor, the Federal Republic of Germany. It should be noted that existing investments will enjoy, in most instances, a ten-year sunset period of protection, but any investments made after the date of termination will not receive any of the investor protections afforded by the BITs.


20 South Africa is a not a signatory to the Convention on the Settlement of Investment Disputes between States and Nationals of Other States (the ICSID Convention) (See International Centre for Settlement of Investment Disputes List of Contracting States and other Signatories of the Convention (as of May 20, 2013) (https://icsid.worldbank.org/ICSID/FrontServlet?requestType=ICSIDDocRH&actionVal=ShowDocument&language=English, Accessed 15 October 2013)). The Administrative Council of ICSID has adopted the Additional Facility Rules authorising the Secretariat of ICSID to administer certain categories of proceedings between States and nationals of other States that fall outside the scope of the ICSID Convention (See the introduction to the ICSID Additional Facility Rules (https://icsid.worldbank.org/ICSID/ICSID/AdditionalFacilityRules.jsp, Accessed 15 October 2013)).
Arbitral Awards (commonly referred to as the New York Convention),\textsuperscript{21} which applies to the recognition and enforcement of foreign arbitral awards and the referral by a court to arbitration.\textsuperscript{22}

\textbf{v} Black economic empowerment in the upstream petroleum industry

The transformation of the upstream petroleum industry is regulated by the Charter for the South African Petroleum and Liquid Fuels Industry on Empowering historically disadvantaged South Africans (HDSAs) in the Petroleum and Liquid Fuels Industry (the Liquid Fuels Charter).

Under the Liquid Fuels Charter, all licences for exploration and production in the country’s offshore area reserve are subject to a minimum 9 per cent buy-in by HDSAs. In addition, the Liquid Fuels Charter envisages that by the end of 2010, HDSAs will own not less than 25 per cent of the aggregate value of the equity of the various entities that hold the operating assets of the South African oil industry.

\textbf{III LICENSING}

Under the MPRDA, a person may apply for a:

\textbf{i} Reconnaissance permit\textsuperscript{23}

The holder of a reconnaissance permit may conduct any operation carried out for or in connection with the search for petroleum by geological, geophysical and photo geological surveys and includes any remote sensing techniques, but does not include any exploration operation other than acquisition and processing of new seismic data.\textsuperscript{24} The Minister must issue a reconnaissance permit if the following requirements are satisfied: financial resources; technical ability; compatibility of the estimated expenditure with the intended reconnaissance operation and duration of the reconnaissance programme; the reconnaissance will not result in unacceptable pollution, ecological degradation or damage to the environment and a NEMA environmental authorisation has been issued; the ability to comply with the relevant provisions of the Mine Health and Safety Act 1996 (MHSA); and non-contravention of any other provision of the MPRDA. A reconnaissance permit issued under section 75(1) of the MPRDA is: subject to prescribed terms and conditions; valid for a period not exceeding one year; not an exclusive right; not transferable; and not renewable.\textsuperscript{25}

\begin{itemize}
  \item \textsuperscript{22} Article 1 of the New York Convention (www.newyorkconvention.org/texts, Accessed 15 October 2013).
  \item \textsuperscript{23} Sections 74–75 of the MPRDA.
  \item \textsuperscript{24} Definition of ‘reconnaissance operation’ in the MPRDA.
  \item \textsuperscript{25} Section 75 of the MPRDA.
\end{itemize}
ii Technical cooperation permit

The holder of a technical cooperation permit may carry out desktop studies including geological, geochemical, geophysical studies, as well as technical research and analysis.

A technical cooperation permit, issued under Section 77(1) of the MPRDA is: subject to prescribed terms and conditions, valid for a period not exceeding one year, not transferable, and not renewable. The holder of a technical cooperation permit has the exclusive right to apply for and be granted an exploration right in respect of the area to which the permit relates.

iii Exploration right

The holder of an exploration right is entitled to reprocess the existing seismic data, acquisition and processing of new seismic data or any other related activity to define a trap to be tested by drilling, logging and testing, including extended well testing, of a well with the intention of locating a discovery. If an application for an exploration right was lodged in respect of a technical cooperation permit, the latter shall, notwithstanding its expiry date, remain in force until such application has been granted or refused.

The Minister must grant an exploration right if the requirements relating to financial resources; technical ability; the compatibility of estimated expenditure with the intended exploration operation and duration of the exploration work programme; the Minister has issued a NEMA environmental authorisation for the operation; the ability to comply with the relevant provisions of the MHSA; non-contravention of any other provisions of the MPRDA and compliance with the terms and conditions of the technical cooperation permit (if applicable) are satisfied. An exploration right granted takes effect on the ‘effective date’, is subject to prescribed terms and conditions and is valid for the period specified in the right, which may not exceed three years. Subject to certain requirements being met, an exploration right may be renewed for a maximum of three periods not exceeding two years each. If a renewal application has been lodged, the exploration right shall, notwithstanding its expiry date, remain in force until such time as such application has been granted or refused.

The holder of an exploration right has the following exclusive rights: to apply for and be granted a production right in respect of the petroleum and the exploration area in question; to apply for and be granted a renewal of the exploration right; and to remove and dispose of petroleum samples found during exploration. The holder of an exploration right must: lodge such right within 60 days for registration at the MPTRO; continuously and actively conduct exploration operations in accordance with the approved exploration programme; comply with the terms and conditions of the exploration right and any relevant law; comply with the terms and conditions of the approved environmental management programme (certain sections of the MPRDA need to be ‘cleaned-up’ in light of the shift of

26 Section and 77 of the MPRDA.
27 Sections 79–80 of the MPRDA. The MPRDA defines ‘effective date’ as ‘the date on which the relevant permit is issued or the relevant right is executed’.
28 Section 80(5) of the MPRDA.
29 Section 81(5) of the MPRDA.
30 Subject to Section 82(2) of the MPRDA.
31 Subject to Section 81 of the MPRDA.
32 Subject to Section 20 of the MPRDA.
environmental regulation to the NEMA under the ‘One Environmental System’. Accordingly, this provision should be read as the conditions of the environmental authorisation granted under the NEMA); pay the prescribed exploration fee to the PASA; and commence with exploration activities within 90 days from the effective date of the exploration right or such extended period as the Minister may authorise.33

iv Production right

The holder of a production right may reprocess the existing seismic data, acquire and process new seismic data or any other related activity to define a trap to be tested by drilling, logging and testing, including extended well testing, of a well with the intention of locating a discovery.

The Minister must grant a production right if: the requirements relating to: financial resources and technical ability; compatibility of the estimated expenditure with the intended production operation and duration of the production work programme; the production will not result in unacceptable pollution, ecological degradation or damage to the environment (and a NEMA environmental authorisation has been issued – this is another provision that will be added to the MPRDA in the clean-up process pursuant to the full implementation of the ‘One Environmental System’); the ability to comply with the relevant provisions of the MHSA; compliance with the MPRDA; financial and other provisions for the prescribed social and labour plan; optimal production in accordance with the production work programme and the prescribed social and labour plan;34 and compliance with the terms and conditions of the exploration right (if applicable) are satisfied.

The Minister must, within 60 days, refuse to grant a production right if the application does not meet all of the requirements referred to in Section 84(1) of the MPRDA35, in which case, he or she must notify the applicant, in writing and with reasons, within 30 days.36

A production right is subject to prescribed terms and conditions, and is valid for the period specified in the right, which may not exceed 30 years.37

The Minister must grant the renewal of a production right if the application complies with the above-mentioned requirements and the holder complied with the: terms and conditions of the right and is not in contravention of the MPRDA, relevant law; production work programme; the prescribed social and labour plan; and the approved environmental management programme (again this, in due course, need to be amended to refer to the NEMA environmental authorisation).

Subject to certain requirements being met, a production right may be renewed for further periods, each of which shall not exceed 30 years at a time. If an application for renewal has been lodged, the production right remains in force, despite its expiry date, until such application has been granted or refused.38

33 Section 82(2) of the MPRDA.
34 Section 84(1) of the MPRDA.
35 Section 84(2) of the MPRDA.
36 Section 84(3) of the MPRDA.
37 Section 84(4) of the MPRDA.
38 Sections 84 and 85 of the MPRDA.
The holder of a production right has exclusive rights: to apply for and be granted a renewal of the production right in respect of the petroleum area in question\(^{39}\) and to remove and dispose of petroleum found during the course of production. The holder must: lodge such right for registration at the MPTRO within 60 days; continuously and actively conduct production operations in accordance with the approved production programme; comply with the terms and conditions of the right, the MPRDA and other relevant laws; comply with the requirements of the NEMA environmental authorisation for the operation and the prescribed social and labour plan; pay the state royalties; and commence with production operations within one year from the date on which a production right becomes effective or such extended period as the Minister may authorise.\(^{40}\)

IV PRODUCTION RESTRICTIONS

Currently no production restrictions are applicable in South Africa.

V ASSIGNMENTS OF INTERESTS

Reconnaissance permits and technical cooperation permits are not transferable.

Exploration rights and production rights or an interest in such rights or a controlling interest in a company (other than a listed company) may, under Section 11 of the MPRDA, only be ceded, transferred, let, sublet, assigned, alienated or otherwise disposed of with the prior written consent of the Minister. The Minister must grant such consent if the transferee satisfies the requirements for the grant of the relevant right.

VI TAX

The income tax treatment of oil and gas companies in South Africa is regulated under Section 26B of the Income Tax Act 58 of 1962 (the Act), read with the Tenth Schedule (the Schedule) to the Act. A company that holds any oil and gas right, or engages in exploration or production under any oil and gas right is regarded as an oil and gas company.

The Minister of Finance may enter into a binding fiscal stabilisation agreement with an oil and gas company. The contract will ensure that the Schedule, as at a date the particular oil and gas right is acquired, will not be amended, for the duration of the period that the oil and gas company holds its rights. The oil and gas company is entitled to rescind the agreement of its own accord.

Oil and gas operators are taxed directly in the form of corporate income tax. This is levied at a rate not exceeding 28 per cent for oil and gas companies.

In cases of oil and gas companies, dividends tax is levied at a rate not exceeding zero per cent. To the extent that an oil and gas company seeks to pay out a divided from income that is not its oil and gas income, such dividend is subject to the default dividend withholding tax of 15 per cent. This may be reduced under double tax treaty provisions.

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\(^{39}\) Subject to Section 86(2) of the MPRDA.

\(^{40}\) Section 86(2) of the MPRDA.
Foreign currency gains and losses of an oil and gas company for income tax purposes, are determined using the functional currency and the translation method used by that specific company for purposes of financial reporting. After calculating taxable income using the functional currency, the amount of tax is converted into South African Rand at the average exchange rate for that year of assessment.

Subject to certain specified exclusions, an oil and gas company is allowed to deduct all expenditure and losses actually incurred in that year in respect of exploration or post-exploration. An additional deduction of 100 per cent of all expenditure of a capital nature actually incurred in that year in respect of exploration under an oil and gas right is allowed, and 50 per cent of expenditure of a capital nature actually incurred in that year in respect of production under an oil and gas right is also allowed.

Any assessed losses in respect of exploration and production may only be set off against the oil and gas income of that company. This includes income from refining of gas derived in respect of any oil and gas right held by that company. The set-off is allowed to the extent that those assessed losses do not exceed that income.

Ten per cent of the remaining assessed losses can be set off against other forms of income derived by the company and the residue rolled over into future years of assessment.

If an oil and gas company disposes of an oil and gas right to another oil and gas company, it can elect either a rollover or participation treatment of tax to apply to it.

If rollover treatment is selected the disposing company is deemed to have disposed of the right for an amount equal to the tax cost, whether it is held as a capital asset or trading stock. In essence this means that there is no capital or revenue gain derived. Participation treatment for disposals is also available. If an oil and gas company disposes of any right to another company, the disposing company will treat any gains arising, whether the right was held as a capital asset or as trading stock, as revenue. Reciprocally, the acquiring entity will be deemed to receive an immediate deduction equal to the gain.

South Africa currently imposes withholding taxes on dividends, interest, royalties and payments in respect of immovable property sold by non-residents.

The tax treatment set out above, in particular the generous tax allowances are intended to operate as tax incentives. In addition, general allowances, such as those for research and development may also be applicable.

Other forms of state support, such as subsidies, may also apply, but these do not strictly fall within the tax regime.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

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

Environmental regulation of the petroleum industry shifted from the MPRDA to NEMA with the practical implementation of the ‘One Environmental System’ on 8 December 2014.

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41 Exploration means the acquisition, processing and analysis of geological and geophysical data or the undertaking of activities in verifying the pressure or absence of hydrocarbons conducted for the purpose of determining whether a reservoir is economically feasible to develop.

42 Paragraph 5 of the Schedule.
For any new applications for rights and or permits, renewal thereof, applicants will need to demonstrate compliance with the NEMA and the requirement to obtain an environmental authorisation or prove compliance with the conditions thereof, as opposed to the historical MPRDA environmental provisions.

Although the ‘One Environmental System’ is in force, the full suite of regulations to complement this shift in environmental regulation has yet to all be brought into force. As of September 2016, the following complimentary regulations have been brought into force: the 2014 National Environmental Impact Assessment Regulations (and associated Listing Notices 1–3), the 2014 National Appeal Regulations, the 2014 National Exemption Regulations the 2015 Regulations Regarding the Planning and Management of Residue Stockpiles and Residue Deposits and the 2015 Regulations Pertaining to the Financial Provision for the Rehabilitation, Closure and Post-closure of Prospecting, Exploration, Mining and Production Operations.

In order for the transition to be holistically implemented, the following additional complimentary regulations must also be brought into force: the 2015 Draft Regulations Regarding the Procedure Requirements for Licence Applications under the NWA and the amendment of the MPRDA Regulations to remove regulations relating to the environment. Section 38B of the Amendment Act (the enactment of this section was delayed in the proclamation of the Amendment Act i.e., Proclamation 17 in Government Gazette 36541) should ideally be brought into force, to provide that environmental management programmes and plans previously approved under the MPRDA will be deemed to be an environmental authorisation issued under the NEMA. However, Section 12(4) of 2008 NEM Amendment Act currently provides that environmental management programmes and plans approved in terms of the MPRDA immediately before the 2008 NEM Amendment Act came into operation (effectively 8 December 2014) must be regarded as having been approved in terms of NEMA, under the guise of the DMR.

A host of other environmental legislation that regulates, inter alia, biodiversity, air quality, waste management, protected areas, heritage resources and land use is also applicable to oil and gas operations in South Africa. Further, the environmental impact of constructing and operating petroleum pipelines and other facilities is regulated by the Petroleum Pipelines Act 2003.

ii Details of regulatory agencies with responsibility for environmental regulation
As described above, the PASA as the designated authority advises the Minister (as the final authority) in granting exploration and production rights and their related environmental approvals, now an environmental authorisation under the NEMA, under the One Environmental System.

Other regulators of note are the Department of Water and Sanitation, the DEA, the National Energy Regulator of South Africa, the South African Heritage Resources Agency and the Department of Agriculture, Forestry and Fisheries.

iii Description of any key environmental approvals necessary for oil and gas activities
As of 8 December 2014, an application for a production or exploration right will also require an application for an environmental authorisation, which is to be approved by the Minister under the NEMA, with the PASA acting as the advising authority.

The draft technical regulations provide for further environmental impact studies and related obligations.
As explained, it is proposed that the exploration for and or production of onshore unconventional oil or gas resources and any activities incidental thereto be declared a controlled activity for which a water use licence is specifically required under the NWA (the process to be followed to apply for a water use licence will be governed by the Draft Regulations Regarding the Procedure Requirements for Licence Applications under the NWA, once enacted). Other approvals that may be required include a waste management licence, biodiversity permits and municipal approvals or registration certificates.

Rehabilitation (including concurrent rehabilitation) must be undertaken by the holder of an exploration or production right and financial provision must be made to fund the costs thereof. The 2015 Regulations Pertaining to the Financial Provision for the Rehabilitation, Closure and Post-closure of Prospecting, Exploration, Mining and Production Operations govern the putting-up of this financial provision, the quantum of which is to be informed by the preparation of an annual rehabilitation plan, a final rehabilitation plan and a latent and patent environmental risk assessment report. Under the changes introduced by the NEM 2014 Laws Amendment Act, the definition of ‘financial provision’ has been extended to include the pumping and treatment of polluted or extraneous water, as well as the remediation of latent or residual environmental impacts which become known in the future. The holder must then apply to the Minister for a closure certificate (the PASA remains the advising authority) within 180 days of the occurrence of the lapsing, abandonment, cancellation, cessation or relinquishment of the right. The holder remains responsible for the environmental liability of the operation until the certificate is issued. Under the 2014 National Environmental Impact Assessment Regulations and specifically Listing Notice 1, a NEMA environmental authorisation will need to be obtained in order to obtain a MPRDA closure certificate. Further, Listing Notice 1 provides that a NEMA environmental authorisation must also be obtained if the throughput of the activity (pursuant to an exploration or production right) has reduced by 90 per cent or more over a period of five years excluding where the DMR has agreed in writing that such reduction in throughput does not constitute closure.

The draft technical regulations provide that a holder may only suspend a well 43 after obtaining the approval of PASA. Inactive, suspended or non-producing wells must be plugged and abandoned in accordance with an abandonment plan approved by PASA. Abandoned wells must be clear of all obstructions and equipment and cemented for the full length and diameter of the well bore to surface.

**VIII FOREIGN INVESTMENT CONSIDERATIONS**

The present control measures were introduced by way of the Regulations as promulgated by Government Notice R1111 of 1 December 1961 and amended up to Government Notice No. R.885 in Government Gazette No. 20299 of 23 July 1999 and Orders and Rules 1961, as published in Government Notice R1112 of 1 December 1961 and amended up to Government Notice R.7445 in Government Gazette No. 35430 of 8 June 2012, issued under the Currency and Exchanges Act No. 9 of 1933 (the Currency and Exchanges Act).

The legal framework of South African exchange control is based on the premise of a total prohibition to deal in foreign exchange, except with permission of, and on the conditions

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43 Means any drilled hole used for the purpose of exploration and production of petroleum resources.
set out by, the Treasury Department. Because of its obvious impact on the conduct of normal international trade and payments, the underlying economic policy is not totally prohibitive. The purpose of exchange control in this context is thus:

- to ensure the timeous repatriation into the South African banking system of certain foreign currency acquired by South African residents; and
- to prevent the loss of foreign currency resources through the transfer abroad of real or financial capital assets held in South Africa.

Thus, in essence, the broad ambit of South African exchange control regulation is to prohibit the export of capital from South Africa by South African residents.

The administration of exchange control in South Africa has been delegated to the South African Reserve Bank (SARB) and administratively performed by the Financial Surveillance Department of the SARB. Certain powers, set out in the Currencies and Exchanges Manual for Authorised Dealers (Authorised Dealer Manual), have been delegated to authorised dealers (banks licensed to deal in foreign exchange).

The distinction between residents of the Common Monetary Area (CMA) and non-residents thereof is crucial for exchange control purposes. Non-residents are not directly subject to exchange control as more fully described below. The CMA comprises South Africa, Lesotho, Namibia and Swaziland.

A South African resident is regarded for exchange control purposes as a person (that is a natural person or incorporated foundation, trust or partnership), whether of South African or any other nationality, who has taken up residence, or is domiciled or registered in South Africa. A non-resident is a person (natural or legal) whose normal place of residence, domicile or registration is outside of the CMA. Although this appears inconsistent, it reflects how the relevant exchange control regulations are drafted.

In the practical application of exchange control, the role of authorised dealers and the nature of their authority must be fully understood. In accordance with the exchange control regulations, no person other than an authorised dealer may trade in foreign currency in South Africa. Authorised dealers are appointed by the SARB and a list of the current authorised dealers can be found on the SARB’s website. The Authorised Dealer Manual issued by SARB details the general and specific authority granted to, and the rules and procedures to be followed by, authorised dealers.

The Authorised Dealer Manual is compiled as a technical handbook for use by authorised dealers containing authorities, instructions and conditions that apply to the wide range of transactions that they may undertake on behalf of their clients. The Authorised Dealer Manual is not intended for use by the public. Instead, Currencies and Exchanges Guidelines for Business Entities and Currencies and Exchanges Guidelines for Individuals are published.

IX CURRENT DEVELOPMENTS

The National Assembly and the National Council of Provinces passed the Bill on 12 and 27 March respectively. The Bill amends a number of key provisions of the MPRDA but has yet to come into effect.

The Bill seeks to:
South Africa

a eliminate the role of PASA under the MPRDA and to transfer PASA’s functions to the DMR’s regional managers. The government has indicated that to the extent possible the intention will be to maintain PASA in its current form but reconstitute it under a new regional manager within the DMR;

b entitle the state to a 20 per cent free carried interest in all new exploration and production rights with an option to acquire a further participating interest in the form of either: an acquisition of a further potentially unlimited participating interest, at ‘an agreed price’;\(^4\) or a production-sharing agreement.\(^5\) Despite this wide-ranging discretion the Minister and the DMR have indicated that only a limited percentage beyond the 20 per cent free carry will be taken up by the state for any given block. In addition, the government has indicated that the 20 per cent free carry likely will be on a cost reimbursement basis and that the state will fund its participation once production commences. The DMR has indicated that such clarifying detail will be set forth in regulations to be promulgated once the Bill takes effect and potentially also set forth in granting instruments or production sharing agreements applicable to any given exploration block. Such additional information has been welcomed by industry though the detail is eagerly awaited;

c introduce a system of ministerial invitation for applications for reconnaissance permits, exploration rights and production rights.\(^6\) The Explanatory Memorandum to the Bill suggests that the ‘first-come-first-assessed’ principle in the processing of applications will be substituted by the ministerial invitation system;\(^7\)

d ensure that the provisions relating to strategic minerals will also relate to ‘petroleum and petroleum products’. This means that petroleum and petroleum products may be declared ‘strategic minerals’. Under Section 49 of the MPRDA, the Minister may prohibit or restrict the granting of exploration and production rights for strategic minerals at any time;

e grant the Minister discretion to apply the revised Mining Charter in substitution of the Liquid Fuels Charter.\(^8\) Should the revised Mining Charter apply, the participating interest of HDSAs would increase from 9 per cent (the threshold required under the Liquid Fuels Charter) to 26 per cent;

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44 It is not clear what ‘an agreed price’ means or how a deadlock will be broken where the state is ‘entitled’ to an interest, but cannot agree with the exploration company in question on a price for such interest.
45 Section 86A(1) and (2) of the MPRDA as amended by clause 65 of the Bill.
46 Section 9 of the MPRDA as amended by clause 5 of the Bill.
47 Paragraph 2.2 of the Explanatory Memorandum to the Bill.
48 Section 80(2) of the MPRDA as contained in clause 57(b) of the Bill. Section 100(2) of the MPRDA required and empowered the Minister to develop a broad based socio-economic empowerment charter for the South African mining industry which would, among other things, set out how the objects referred to in Section 2 (c), (d), (e), (f) and (i) of the MPRDA may be achieved. On 13 August 2004, the Minister published the Broad-Based Socio-Economic Empowerment Charter for the South African Mining Industry of 2002. The Minister subsequently published the revised Mining Charter on 13 September 2010. The revised Mining Charter stipulates the requirements for black economic empowerment in the South African mining industry.
introduce further changes to the MPRDA to align with the One Environmental System for the petroleum industry and which are critical to the effective implementation of this system. Instances of misalignment with the One Environmental System have been identified in this chapter. These, and other instances need to be ‘cleaned-up’ in changes to the MPRDA; and

introduce obligations for applicants for exploration and production rights to apply for a licence to use water under the NWA. The NWA has been amended to provide that the Minister of Water and Sanitation must align and integrate the process for consideration of a water use licence with the timeframes and processes applicable to applications for exploration or production rights in terms of the MPRDA and environmental authorisations in terms of the NEMA.

The President has elected to not assent to the Bill and has referred the Bill to the National Assembly raising the following constitutional reservations:

a the definition of the term, ‘this Act’, purports to elevate policy documents and industry charters including: (1) the Codes of Good Practice for the South African Minerals Industry, 2009; (2) the Housing and Living Conditions Standard for the South African Minerals Industry, 2009; and (3) the Amendment of Broad-Based Socio-Economic Empowerment Charter for the South African Mining and Minerals Industry, 2010, (collectively referred to as the ‘Instruments’) to the status of national legislation. The Instruments, according to the President, are subject to amendment without the advent of the rigorous legislative process prescribed by the Constitution for the amendment of legislation (the Instruments Reservation);

b the Bill’s beneficiation provisions are inconsistent with South Africa’s obligations under the General Agreement on Tariffs and Trade, 1947 and 1994 (GATT) and South Africa’s Trade, Development and Cooperation Agreement (TDCA) with the European Union (EU);

c the National Council of Provinces (NCOP) and the provincial legislatures did not facilitate sufficient public participation during the parliamentary processes as required by Sections 72 and 118 of the Constitution; and

49 Sections 73–89 of the Constitution.

50 The GATT is a multilateral international agreement, which regulates trade and is administered by the World Trade Organisation (WTO). South Africa was one of the founding parties to the GATT. The GATT was amended by the General Agreement on Tariffs and Trade, 1994. The GATT 1994 provided for the creation of the WTO. South Africa ratified the GATT 1994 on 2 December 1994. GATT is thus binding on South Africa under Section 231(5) of the Constitution, which provides that South Africa is bound by international agreements that were in force when the Constitution took effect on 4 February 1997.

51 The TDCA was signed in October 1999, and provisionally applied – but only partially – from 1 January 2000. The TDCA fully entered into force on 1 May 2004. It forms the legal basis for overall relations between South Africa and the European Union, and covers five areas of cooperation: political dialogue; development cooperation; cooperation in trade and trade-related areas; economic cooperation; and cooperation in other areas.
the Bill should have been referred to the National House of Traditional Leaders under Section 18 of the Traditional Leadership and Governance Framework Act 2003, owing to the Bill’s impact on customary law or the custom of traditional communities, presumably read with Section 212 of the Constitution;

In summary, the following processes have been initiated:

\[a\] the Speaker has referred the Bill together with the President’s reservations to the Portfolio Committee. The Portfolio Committee is reconsidering the MPRDA Bill in light of the President’s reservations, being of both a substantive and procedural nature, and will shortly confer with the NCOP’s Select Committee;

\[b\] on the procedural defects raised, primarily the lack of public participation in the NCOP, it is likely that additional public hearings will be convened by the Select Committee to cure such procedural defects. This may result in the provisions relating to oil and gas being reopened for debate.

It is unclear, at this stage, whether the Portfolio Committee will deem the MPRDA Bill to be so defective either procedurally or substantively that it cannot be amended, in which case the NA must consider rejection of the MPRDA Bill in its entirety.

Further, in the likely event that the Select Committee convenes additional public hearings, it is important that affected parties participate in such hearings.

In the interim, the status quo, being the regime applicable under the MPRDA, is preserved.

The published technical regulations for petroleum exploration and production has sought to augment gaps that were identified in the current oil and gas regulatory framework under the MPRDA, particularly in relation to hydraulic fracturing.

While the Minister has given the go-ahead for shale gas exploration in the Karoo, exploratory drilling in the Karoo shale gas fields is likely to commence only after the completion of the inter-ministerial committee’s consideration of the Bill.

These recent developments should be seen as an attempt by the South African state to foster the rapidly growing oil and gas industry in South Africa. However, many of the Bill’s amendments to the MPRDA have posed challenges that need to be resolved. In attempting to resolve the issues, it is important for the South African state not to lose sight of the socio-economic benefits that can be unlocked from the development of a well-regulated oil and gas industry. In the present economic environment, it is vital for the state to provide investors with the wherewithal to assess opportunities and factor in risks with regulatory certainty. Recent communication by the government appears to indicate that the government appreciates the concerns of investors and is working to provide additional clarity and strike an appropriate balance. The next 12 months should prove determinative for the long-term trajectory of South Africa’s upstream oil and gas industry given the commencement of exploration activity offshore, the anticipated commencement of exploration activity onshore and the ongoing regulatory development taking place.
I INTRODUCTION

Switzerland is one of the leading business locations in the world. Its success is mainly due to high-quality products and services, an investor and business-friendly government, modest taxation, currency and price stability, a first-rate infrastructure, efficient capital markets and a highly professional international banking system. Excellent education as well as political stability further contribute to Switzerland’s attractiveness for businesses. However, natural resources, except for water, are scarce.

Although Switzerland has gas reserves, in most cases these are too small to merit production. The area of Finsterwald, where some gas was produced between 1985 and 1994, remains the only example of domestic gas production. However, during a drilling attempt in St. Gallen in 2013 regarding a geothermal energy project a gas reserve has been discovered. The drilling attempt was unsuccessful due to seismic activity. At the moment a feasibility study is carried out in order to analyse options to produce gas on this site. Today, Switzerland relies solely on imports to meet its annual gas consumption. There are indications, however, that the production of shale gas is possible in Switzerland.

The stable legal framework in connection with the expertise in commodity trading and its guaranteed financing led to an increasing number of commodity traders locating in Switzerland. Besides London, Switzerland (mainly Zug, Geneva and Lugano) has developed into the world’s leading location for commodity trading. Hence, despite the lack of natural resources mentioned above, Switzerland may take a more meaningful role in the gas and oil sector in the next few years.

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II LEGAL AND REGULATORY FRAMEWORK

As there is no production of oil and gas, Switzerland does not have a specific regulatory framework regulating the production and no comprehensive framework governing the import, storage, transport and distribution of oil and gas. With regard to trading commodities, Switzerland’s legal framework is characterised by a rather low level of regulation.

i Domestic oil and gas legislation

Switzerland relies fully on imports of oil and gas. Although there are no upstream operations in Switzerland, this does not mean that there is no legal framework. Energy policy was introduced into Swiss law in 1990. According to Article 89 of the Constitution, the Confederation and the cantons are obliged to provide a sufficient, diversified, safe, economical and environmentally sustainable energy supply as well as the economical and efficient use of energy. Due to certain geographical conditions in Switzerland, the implementation of the energy provisions in the Constitution has largely focused on midstream and downstream oil and gas.

In order to secure the necessary gas imports so that domestic demand can be met, long-term supply agreements between private entities and major foreign gas providers are concluded for up to 25 years. Around 50 per cent of Switzerland’s gas demand is guaranteed by four agreements between Switzerland’s main importer, Swissgas AG and four foreign providers from Germany and the Netherlands. The remaining gas required is imported from France and Germany.

Switzerland also fully depends on imports regarding oil. Based on the Constitution, the supply of essential goods is a task to be fulfilled by the private sector. The National Economic Supply Act considers oil as an essential good. Public supply is only activated if supply shortfalls occur. This subsidiarity principle is complemented by the militia principle: industry experts carry out risk assessments and use these to plan the control measures to be taken. Such regulation includes stockpiling and the import of oil. However, the regulation of oil imports aims mainly to secure that the importers actually hold the needed stocks.

Storage becomes important to hedge against fluctuations on the global market due to natural disasters, political crises or other disturbances. In this regard, Article 102 of the Constitution states that the Confederation shall ensure that the country is supplied with essential goods in the event of war or of any other severe shortage that the economy cannot counteract by itself. The Confederation has to take precautionary measures to address these matters. In exercising its powers, it may be necessary to depart from the principle of economic freedom. The National Economic Supply Act as well as its associated Ordinance concerning the Compulsory Stockpiling of Liquid Fuels and Combustibles regulate the stockpiling of oil

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3 Federal Constitution of the Swiss Confederation of 18 April 1999 (SR 101).
in further detail.⁶,⁷ The requirements for stockpiling of oil in storage facilities and the storage of gas are primarily governed by environmental law including, for example, the Waters Protection Act and the associated Waters Protection Ordinance.⁸

Article 91 of the Constitution provides the Confederation with a basis for the legislation on pipelines. This competence was put into execution with the Pipeline Act, the Pipeline Ordinance, and the Ordinance concerning Safety Standards for Pipelines.⁹ The Pipeline Act and its associated ordinances are to be applied to the planning, the construction, the operation and the maintenance of the pipelines transporting liquid and gaseous fuels only. The pipelines are classified into three categories by the federal legislation according to their dimension and the maximal operating pressure within the pipeline, among other criteria:

a Big pipelines as defined in the Pipeline Ordinance, as well as all pipelines in the property of the Confederation and those crossing Swiss borders are under the supervision of the Swiss Federal Office of Energy (SFOE). Federal law applies.

b Pipelines with smaller dimensions or a small operating pressure (as defined in the Pipeline Ordinance) are under cantonal supervision with cantonal law being applicable.

c Excluded from the application of the Pipeline Act are all pipelines within the immediate proximity of gas plants since they are governed by regulations applying to the gas plants themselves.

The pipeline system for oil is not as extensive as the system for gas distribution. Only crude oil is transported directly by pipelines to the refineries in Switzerland.¹⁰ The legal regime on pipelines mentioned above is applicable in this context. The finished products are transported domestically by rail and road. Crude oil, mineral oil as well as finished mineral oil products are also imported via the harbour of Basle by Rhine ships. Primarily, the Inland Navigation Act and the Inland Navigation Ordinance regulate domestic navigation.¹¹ Also applicable to the shipping of oil products on the Rhine is the Ordinance concerning the Carriage of Dangerous Goods on the Rhine, which is based on Article 25 of the Inland Navigation Act.¹² Further applicable in this context is the Major Accidents Ordinance.¹³ Import also takes place by rail and road. Article 87 of the Constitution outlines the Confederation’s competence to legislate in the field of navigation and rail transport. Article 82 of the Constitution contains

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7 Weber, Energy Law in Switzerland, 142 f.
9 Pipeline Act of 4 October 1963 (SR 746.1); Pipeline Ordinance of 2 February 2000 (SR 746.11); Ordinance concerning Safety Standards for Pipelines of 20 April 1983.
11 Inland Navigation Act of 3 October 1975 (SR 747.201); Inland Navigation Ordinance of 8 November 1978 (SR 747.201.1).
12 Carriage of Dangerous Goods on the Rhine Ordinance of 29 November 2001 (SR 747.244.141).
the comprehensive federal competence to legislate on road traffic. Article 3 of the Road Traffic Act determines that the cantons remain competent in this respect.\textsuperscript{14} For gas and oil, railway and road planning are governed by the Railway Act and the National Roads Act of 8 March 1960.\textsuperscript{15,16}

Since the Constitution does not assign the Confederation with the competence of gas supply, the cantons would be competent to provide a legal regime. Generally, gas supply is a task for the municipalities. However, cantonal statutes do not explicitly provide the municipalities with the authority to legislate on gas supply, instead this forms part of customary law. Since in reality it would not make sense to limit the supply of gas just to the territory of one municipality, one municipal gas work usually supplies an area consisting of several municipalities.\textsuperscript{17} As gas is regularly supplied by only one single gas distributor for one area, gas distribution companies have a natural monopoly on the corresponding area. This competition is only relativised by the intensive competition on the heating market. This competition is caused on one hand by substitutes like oil or electricity and on the other hand by the partial liberalisation of the gas market based on Article 13 of the Pipelines Act. However, owing to the limited content of this Article an association agreement between the providers and the industrial customers regarding gas was signed in 2012. This agreement addresses issues such as the access to the distribution network, the fee for transit and the capacity management. According to a recent amendment of this agreement, the bar of market access for customers has been lowered from a consumption of 200 to 150 Nm\textsuperscript{3}/h as per 1 October 2015. Consequently, more industrial customers have the free choice of a provider. This private market regulation may contradict with the provisions of the Swiss Cartel Act.\textsuperscript{18} The Secretariat of the Competition Commission voiced several concerns in this regard, without taking any actions so far, however.\textsuperscript{19} The federal government intends to introduce new legislation for gas transportation and distribution until 2020. A first draft is expected to be ready for public consultation in 2017.

\textbf{ii} \hspace{1em} \textbf{Regulation}

As Switzerland produces neither gas nor oil, there are no regulatory authorities for those commodities regarding production. However, the Swiss institutional framework involves several federal offices, regulatory authorities and specialised agencies acting as a regulatory authority.

The SFOE is the country’s competence centre for issues relating to energy supply and energy use at the Federal Department of the Environment, Transport, Energy and Communications. The SFOE is in charge of the application of the Pipeline Act and the corresponding Pipeline Ordinance. Besides creating the necessary conditions for efficient electricity and gas markets and an adapted infrastructure, the SFOE is in charge of guaranteeing

\begin{footnotesize}
\begin{enumerate}
\item Road Traffic Act of 19 December 1985 (SR 741.01).
\item Railway Act of 20 December 1957 (SR 742.101).
\item National Roads Act of 8 March 1960 (SR 725.11).
\item Weber, Energy Law in Switzerland, 132.
\item Federal Act on Cartels and other Restraints of Competition (SR 251).
\item Final report dated 16 December 2013 regarding association agreement gas Switzerland RPW 2014/1, 110.
\end{enumerate}
\end{footnotesize}
the prerequisites for a sufficient, crisis-proof, broad-based, economic and sustainable energy supply and ensuring the maintenance of high safety standards in the production, transport and utilisation of energy.\textsuperscript{20}

Concerning transportation, the key institutional player is the Swiss Federal Pipelines Inspectorate (FPI). The FPI supervises everything that is subject to the Pipeline Act, for example, the supervision of the planning, construction and operation of pipeline systems for the transport of liquid and gaseous combustibles and motor fuels. Moreover, the FPI aims to protect human life and the environment above profitability.\textsuperscript{21} All its activities are designed to maintain a high level of safety of pipeline systems in Switzerland. The FPI’s activities allow political and legal bodies to take decisions without having to yield to economic restraints. Furthermore, the FPI sets out to promote the familiarity of pipeline operators with new pipeline technologies. The aim of keeping the technical status of official requirements at a comparable level is pursued by maintaining domestic and international contacts with specialised bodies and authorities.\textsuperscript{22}

In addition to the FPI, it is the responsibility of the SFOE and the Swiss Federal Office for the Environment\textsuperscript{23} to ensure that the regulations of the high-pressure gas network are correctly observed.

CARBURA is a private association of importers of liquid fuels and combustibles for compulsory stockpiling, which was founded in 1932. Members either import more than 3,000m\textsuperscript{3} of petroleum products per year or are common respectively substitute stockholders that concluded a compulsory stockpiling contract with the federal administration. The articles of association are approved by the Federal Department of Economic Affairs, Education and Research\textsuperscript{24} and overall supervision is carried out by the Federal Office for National Economic Supply. CARBURA carries out two functions regarding national economic supply. First, it guarantees that the compulsory supplies are being stockpiled. Second, it also assists in the planning and carrying out of measures for national economic supply. Moreover, CARBURA issues import permits, levies guarantee fund contributions and manages the guarantee funds, and pays compensation to stockholders for the costs of compulsory stockpiling. Various staff at the branch office and partner companies carry out executive and expert functions in the Petroleum Products Department of the Energy Division of National Economic Supply and support the respective authorities in the context of the International Energy Agency.\textsuperscript{25}

\textbf{iii} Treaties

Switzerland is a civil law country with a long tradition as one of the major global venues for international arbitration and litigation. With its reliable court system the proceedings are comparably fast and quite cost-effective.

\begin{itemize}
  \item \textsuperscript{20} www.bfe.admin.ch/org/index.html?lang=en.
  \item \textsuperscript{22} www.bfe.admin.ch/eri/index.html?lang=en.
  \item \textsuperscript{23} For more information: www.bafu.admin.ch/index.html?lang=en.
  \item \textsuperscript{24} www.wbf.admin.ch/wbf/en/home.html.
  \item \textsuperscript{25} www.carbura.ch.
\end{itemize}
Switzerland is party to a number of bilateral and multilateral treaties governing the recognition and enforcement of foreign awards and judgments. If there is no treaty governing the recognition and enforcement, the Swiss Private International Law Act (PILA) is applicable.26

The most important multilateral treaty is the Convention on the Jurisdiction and the Recognition and Enforcement of Judgments in Civil and Commercial Matters (the Lugano Convention).27 In its essence, the Lugano Convention is equivalent to the Brussels Regulation. Besides, there are, on an intra-state level, the Swiss Civil Procedure Code (CPC) as well as the Federal Debt Enforcement and Bankruptcy Act (DEBA).28,29 On an international level, the PILA and with respect to foreign arbitral awards, the UN Convention on the Recognition and Enforcement of Foreign Arbitral Awards (the New York Convention) are to be mentioned.30

On 1 January 2011, the CPC, the revised Lugano Convention and the revised provisions of the DEBA on pre and post-judgment attachment all entered into force. In addition, Switzerland has a number of bilateral treaties on the recognition and enforcement in civil and commercial matters with Germany, Austria, Belgium, Spain, Italy, Liechtenstein and Sweden. So far, Switzerland is not a signatory member of the Hague Convention on the Recognition and Enforcement of Foreign Judgments in Civil and Commercial Matters.

The State Secretariat for Economic Affairs (SECO) is the responsible body for negotiating international law disciplines on foreign investment, particularly in the form of bilateral investment promotion and protection agreements (BITs). Due to the absence of a multilateral framework, Switzerland negotiates international law disciplines on the protection of investments on bilateral tracks in the form of BITs. Today, there are 118 BITs in effect.31 Moreover, through the European Free Trade Association (EFTA) Switzerland negotiates free trade agreements of which some contain provisions on investment. SECO represents Switzerland in bodies of international institutions such as the World Trade Organization, Organisation for Economic Co-operation and Development (OECD, UNCTAD, etc.

As far as multilateral investment rules that apply to specific sectors are concerned, Switzerland adhered to the Energy Charter Treaty (ECT). As a consequence, this creates investment protection for non-commercial risks associated with investments in the energy sector. The ECT also includes an investor–state dispute settlement mechanism. However, an initially planned schedule to this treaty that would have covered the liberalisation of investments in the energy sector was not realised. In addition to Switzerland, the signatory countries to the ECT include all EU Member States, all Balkan countries as well as all members of the Commonwealth of Independent States (with the exception of Russia) and Japan.32

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27 Convention on the Jurisdiction and the Recognition and Enforcement of Judgments in Civil and Commercial Matters of 1 January 2011 (SR 0.275.12).
29 Federal Debt Enforcement and Bankruptcy Act of 11 April 1889 (SR 281.1).
30 UN Convention on the Recognition and Enforcement of Foreign Arbitral Awards of 10 June 1958 (SR 0.277.12).
31 Find the full list at: http://unctad.org/Sections/dite_pchb/docs/bits_switzerland.pdf.
32 www.seco.admin.ch/seco/en/home/Aussenwirtschaftspolitik_Wirtschaftliche_Zusammenarbeit/Wirtschaftsbeziehungen/Internationale_Investitionen/
Switzerland has one of the most comprehensive networks of double tax treaties and is therefore very attractive as a business location from a tax perspective. For relations with EU companies, withholding tax on dividend, interest and royalty payments can be reduced to nil in most cases based on the EU–Switzerland Saving Directive (the Saving Tax Agreement). Switzerland does not levy Swiss withholding tax on royalty payments.

III PRODUCTION RESTRICTIONS

So far, there has been no actual extraction of shale gas in Switzerland. Shale gas deposits are expected to lie in north-eastern Switzerland (in particular St. Gallen), below Lake Geneva, and in the Lower and Middle Jura including the canton of Fribourg. It is assumed that at current rates of gas consumption, these deposits could meet Switzerland’s demand for 15 to 30 years. Due to the depletion of conventional energy resources and mainly as a result of advances in drilling technology, the production of shale gas reserves appears to be economically attractive for Switzerland as well. In particular, the awarding of concessions for the extraction of shale gas north of Lake Constance (on German territory) has prompted debates in Switzerland.

In March 2013, the Centre for Technology Assessment, the Swiss Federal Office of Energy, the Commission for Technology and Innovation, and the Swiss Academy of Engineering Sciences introduced a study entitled ‘Energy from the earth’s interior: Deep geothermal energy as the energy source of the future?’. The project, which is led by the renowned Paul Scherrer Institute, aims to address the impact of shale gas extraction. A member of the Swiss parliament addressed the issue in a motion in December 2012. In its response, the Federal Council emphasised that Switzerland’s interests are represented by the Swiss delegation to the International Commission for the Protection of Lake Constance (IGKB). In the IGKB’s opinion, extraction is incompatible with the drinking water abstraction in the affected region. However, the Federal Council would have no jurisdiction concerning drilling projects planned in Germany. In Switzerland, under Article 21.7 of the Annex to the Environmental Impact Assessment Ordinance, such an assessment for shale gas extraction would have to be conducted by the canton concerned.33 In 2011, the cantons of Fribourg and Vaud decided that exploration and hydraulic fracturing for shale gas extraction on their territory would be suspended indefinitely.34

At present, there are a number of pending questions regarding shale gas and its extraction in Switzerland and the sector is open to further development. The cantons of Berne and Neuchâtel are discussing or have already passed a provisional prohibition of the exploration and hydraulic fracturing for shale gas extraction.35 At the same time, the Swiss firm SEAG Ltd in cooperation with the Texan firm eCorp International LLC is preparing test bores for shale gas in parts of the Canton Berne and Vaud. The British company Celtique Energy Ltd is also analysing possible extraction of shale gas in Berne.36

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35 http://www.defacto.expert/2016/06/06/fracking-zweifelsfall-nein/.
36 www.woz.ch/-4460; for further information of the projects of SEAG ltd visit: http://seag-erdgas.ch/news/.
IV TAX

The Swiss tax system features different taxes at federal, cantonal and communal level and allows for competition among cantons and municipalities to attract good taxpayers by offering a better tax climate. As a result, there are certain cantons with particularly low tax rates. Generally speaking, taxation in Switzerland is moderate when compared to European standards.

In principle, no special taxation is applicable to upstream oil and gas operators. Such companies are taxable on their profit and capital. The tax rate depends on the location of the company. For ordinary taxed companies the range is between 12 and 24 per cent on the profit before tax. The tax itself is tax deductible.

For companies with only limited commercial activities in Switzerland (i.e., with more than 80 per cent of the income and of the costs from non-Swiss sources), the privileged tax status of a mixed company is available. The taxable net profit of a mixed company is assessed in accordance with divisional calculation. This would lead to an effective tax rate of about 9 to 11 per cent on the profit before tax. International trading companies particularly benefit from such privileged tax status.

Cantonal and federal tax authorities issue tax rulings on the tax consequences of any transaction submitted to them prior to the consumption of the transaction as well as regarding the applicability of a privileged tax status. This leads to a very constructive attitude and stable tax environment in Switzerland.

V ENVIRONMENTAL IMPACT AND DECOMMISSIONING

In general, the legal frameworks for energy and environment are separate, however, overlaps do exist. There is both environmental protection law and spatial planning law.

Inter alia, environmental law regulates the approval process of fossil fuels and combustibles and the protection of waters in the context of electricity production, as well as measures against liquids endangering the water quality. On the domestic level, legislation concerning protection of the environment is mainly to be found on the federal level in about 10 federal acts and over 50 federal ordinances. Climate change is largely caused by the emission of greenhouse gases. The consumption of fossil fuels as an emissions source of carbon dioxide is primarily governed in the regulation on air pollution control. The Ordinance on Air Pollution Control aims, inter alia, at the protection of human beings, animals, plants and the soil against harmful air pollutants or air pollutants that become a nuisance.

As mentioned above, the transport and distribution of oil and gas have an effect on the Swiss landscape: pipelines and storage facilities are just two examples. Taking environmental objectives into account, appropriate and economical use of the land and a proper settlement policy are the two main objectives of spatial planning law. Specifically, zoning concepts and the environmental impact assessments required by Swiss spatial planning law function as legal instruments for the coordination and integration of environmental and energy aspects. Based on Article 75 of the Constitution, the Confederation has competence to draw up the

37 Weber, Energy Law in Switzerland, 175.
38 Ordinance on Air Pollution Control of 16 December 1985 (SR 814.318.142.1).
principles for spatial planning. Although the cantons have mostly delegated their competence to municipalities, they are responsible for the actual zoning by means of spatial planning instruments.

VI FOREIGN INVESTMENT CONSIDERATIONS

i Establishment

Switzerland offers an advantageous, multilingual environment for establishing a business or even the headquarters of a group of companies. As pointed out above, Swiss corporate law is characterised by a relatively low level of regulation. There are several options when it comes to selecting the most suitable form of organisation for a business. Swiss corporate law offers a variety of legal forms, both in the form of a legal (and separately taxable) entity or in the form of a partnership. Among the companies, the limited liability company (GmbH, LLC) and the stock company (AG Ltd) are very widely used. The registration procedure for a legal entity usually takes around one week from the date of filing.

To set up a stock company, a minimum share capital of 100,000 Swiss francs is required, with at least 20 per cent (and in any case not less than 50,000 Swiss francs) paid up. At least one authorised and registered signatory must be resident in Switzerland. A stock company can issue different types of shares, including preferred shares, voting shares or shares without voting rights.

To set up a limited liability company, a minimum capital of 20,000 Swiss francs is required. At least one authorised and registered signatory has to be resident in Switzerland. Due to the smaller amount of registered capital, the limited liability company is a practical alternative to the stock company, in particular for small to medium-sized companies. In contrast to the stock company, each stockholder must be registered in the commercial register.

A Swiss branch office of a foreign company has to provide a registered Swiss business address. However, the branch office is not considered an independent Swiss entity (i.e., the foreign parent bears the legal responsibility). The foreign parent company, the branch itself as well as at least one authorised signatory (who must be a Swiss resident) needs to be entered into the commercial register.

The general accounting regulations are brief. The annual report of a stock company or a limited liability company must contain the financial statement (balance sheet and profit and loss statement), the business report and consolidated financial statements to the extent required by law. Publicly listed companies and large to medium-sized companies must have their accounts audited by an independent certified auditor. Small companies may have their accounts audited in a limited form or may choose to opt out of the obligation to audit, provided that they have no more than 10 full-time employees. The financial statements may be prepared according to internationally accepted standards such as US-GAAP or IFRS.

Switzerland is home to a number of large international trading companies, whose business consists of buying commodities and selling them again to third parties. Those commodities, such as oil and gas, never enter Switzerland but are sold worldwide. About 500 companies with approximately 10,000 employees in the industry of commodity trading operate in Switzerland. These companies are mainly located in Zug, Geneva and Lugano. The commodity trading industry has grown in recent years. It accounted for approximately
3.9 per cent of the GDP in 2014, which is more than tourism or the cross-border banking business.\(^\text{39}\) Companies such as Vitol, Glencore Xstrata, Gunvor, Trafigura and Mercuria Energy Group have their domiciles in Switzerland.

**ii Capital, labour and content restrictions**

Switzerland does not have any restrictions on the movement of capital.

Switzerland offers an advantageous, multilingual environment. As a possible consequence of this environment, about one-fifth of Switzerland’s population is of foreign origin and one-third of the workforce in Switzerland are foreign nationals. Switzerland is a world-class business location that attracts domestic as well as international companies, including oil and gas trading companies. The very same companies attract and employ highly trained, specialised manpower.

The Swiss government has been gradually adapting its policy on foreign nationals and migration to more modern standards and thus taking into account international developments. Its policy is embodied in the Foreign Nationals Act (FNA).\(^\text{40}\) In the context of the conclusion of bilateral agreements with the EU on the free movement of persons, Switzerland introduced a dual system of recruitment for foreign labour. The Bilateral Agreement on the Free Movement of Persons, which came into force on 1 June 2002, confers upon the citizens of Switzerland and of EU Member States the right to freely choose their place of employment and residence within the national territories of the contracting state parties. Under this system, people from EU and EFTA Member States are granted priority admission to the Swiss labour market over people from other countries. Pursuant to the provisions of the Agreement on the Free Movement of Persons, Switzerland and the EU have agreed to implement the complete freedom of movement of persons by 2014. Based on the acceptance of the initiative ‘Against mass immigration’ by a majority of the electorate, the future development of the complete freedom of movement of persons is unsure.\(^\text{41}\)

Workers from third countries – nationals from neither EU or EFTA Member States nor Switzerland – must have a work permit. Regulations on how to obtain such a permit are considerably stricter than for most European countries and are often directly tied to employment. To obtain a work permit, employers have to prove that a person cannot be recruited from the labour market of Switzerland or another EU or EFTA Member State. Pursuant to legal practice based on Article 21 FNA, management, experts and other qualified employees will be admitted. ‘Qualified employee’ means, first and foremost, someone with a degree from a university or institution of higher education as well as several years of professional experience. Depending on the profession or field of specialisation, other people with special training and several years of professional work experience may also be admitted. However, an applicant is also required to fulfil certain other criteria that would facilitate his or her long-term professional and social integration, such as professional and social adaptability, knowledge of a Swiss language (or languages) and age.\(^\text{42}\)


\(^{40}\) Federal Act on Foreign Nationals of 16 December 2005 (SR 142.20).

\(^{41}\) www.ejpd.admin.ch/jejpd/de/home/aktuell/abstimmungen/2014-02-09.html.

Switzerland

Swiss labour law is fairly liberal. The freedom of the employer or the employee to terminate the employment agreement, subject to the applicable notice period, is a fundamental principle of Swiss labour law. With strictly limited exceptions, terminations are legally valid and binding while subject to relatively low compensation.

iii Anti-corruption

Switzerland supports various international instruments aimed at fighting corruption and is actively involved in the further development of these measures. These measures include the Convention of 1997 signed by the OECD members on combating bribery of foreign officials in international business transactions. As a direct consequence, the signatories made amendments to their legislation in a coordinated action and made the bribery of foreign public officials a punishable offence. To guarantee that the Convention is implemented and applied in all participating states, a far-reaching monitoring procedure has been set up. The Criminal Law Convention on the fight against corruption, which passed under the auspices of the Council of Europe in 1999 and was acceded to by Switzerland, goes beyond the OECD Convention since it contains the general minimum requirements for criminal law provisions to fight both private and public corruption. The UN Convention against Corruption was signed by more than 100 countries including Switzerland in December 2003. This Convention came into force in 2005. Switzerland ratified this Convention because of its universal nature and the inclusion of provisions with respect to the restitution of funds acquired through illegal and corrupt practices.

In the past decade, Switzerland has introduced the penalisation of bribery of foreign public officials and of private individuals. It further introduced the prosecution of companies (and not just individuals) for corruption in its criminal law. Not only management and staff are potentially criminally liable, but also those who otherwise act on behalf of the company. Pursuant to Article 716a of the Code of Obligations (CO) it is the board of directors’ non-transferable and inalienable duty to oversee that management complies with laws, statutes, regulations and orders.43 If a company has not undertaken all requisite and reasonable organisational precautions that would be required to prevent the bribery of public officials or persons in the private sector, it will be subject to criminal prosecution and a fine of up to 5 million Swiss francs.

Many internationally operating Swiss companies have already decided to introduce an anti-corruption code of conduct. Such a code has several advantages: employees are confronted with the problems of corruption and their implicit consequences; they receive guidance on how to recognise corruption in good time and how to fight it. Furthermore, the company’s business partners and clients, as well as the general public, perceive the company to be reliable and trustworthy.

By adopting an anti-corruption code of conduct, a company undertakes to act with integrity. Normally, a code of conduct encompasses general principles, rules of conduct to prevent corruption from arising and instructions on how to proceed in a case.44


VII CURRENT DEVELOPMENTS

Switzerland hosts many energy and commodity trading companies, in particular in the Geneva and Zug area, and consequently is a leading location in this sector.

For example, Switzerland is a favoured host country for new international energy project companies, such as Trans Adriatic Pipeline Ltd (which is a natural gas pipeline project in south-east Europe) and Nord Stream Ltd (a twin gas pipeline system through the Baltic Sea). It is expected that more project companies will be set up in Switzerland.

In relation to the energy strategy 2050 currently discussed in the Swiss parliament\textsuperscript{45} gas could become increasingly important in Switzerland, since the development of new technologies, such as power-to-gas, could help to manage production peaks from renewable sources, such as wind and solar power.\textsuperscript{46} In this regard, it is worth mentioning, that Swiss institutions and firms participate in an EU research programme regarding energy storage and power-to-gas.\textsuperscript{47} In addition, Swisspower, an association of companies, which controls more than half of the distribution market for gas, intends to develop two power-to-gas-plants to enrich biogas in order to gain methane.\textsuperscript{48}

\begin{itemize}
\item \textsuperscript{45} http://www.bfe.admin.ch/energiestrategie2050/index.html?lang=en.
\item \textsuperscript{46} https://www.psi.ch/media/turning-electricity-into-gas-and-back-into-electricity.
\item \textsuperscript{47} https://www.regioenergie.ch/fileadmin/regioenergie/Unternehmen/Dokumente/Medienmitteilungen/MM_Store_Go_2016.pdf.
\end{itemize}
I INTRODUCTION

The United Kingdom has a long history of oil and gas production, having onshore production since the 1930s and much more significantly, large-scale offshore oil and gas production from the 1970s to the present, with the first commercial offshore oilfield, Argyll, commencing production in 1975.

According to industry body Oil & Gas UK (OGUK), more than 43 billion barrels of oil equivalent (boe) have been extracted from the UK Continental Shelf (UKCS). Production from the UKCS peaked in 1999 and there has been a general decline since. In 2005, the United Kingdom became a net importer of crude oil for the first time since the early 1990s. The OGUK’s Activity Survey 2016 states that, although production on the UKCS rose by 9.7 per cent in 2015 to 1.64 million barrels of oil equivalent per day, the revenues fell to the lowest rate since 1998, lying at £18.1 billion for 2015. The price of oil in 2015 averaged US$52 per barrel (bbl) compared with an average of US$38/bbl in 2016. To adapt to lower price environment the industry committed to substantial cost-cutting, with operating costs falling 28 per cent from $29.30/boe to $20.95/boe. But the impact of the reduced oil price has had further ramifications entailing widespread redundancies in the workforce and a huge loss of taxation income for the UK government. With global oversupply, the industry faces uncertainty going into 2017 and will be largely determined by Iran re-entering the market, oil consumption and demand growth (in particular China’s ability to halt its economic slowdown), and the cooperation of OPEC and non-OPEC producers (such as Russia) to influence the oil price in the face of stiff competition from the US shale producers.

In its history, the UK offshore oil and gas industry has faced many challenges and developments in its regulatory framework. Regulation of the industry is currently in a state

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1 Penelope Warne is senior partner and Norman Wisely is a partner at CMS. The authors would like to thank Konrad Rawicz, lawyer at CMS, for his assistance in drafting this chapter.
II LEGAL AND REGULATORY FRAMEWORK

Challenges met over the years have forced the industry to sculpt a comprehensive and recognisable legal framework, both at domestic and international level.

i Domestic oil and gas legislation and regulation

The Petroleum Act 1998 vests ownership of petroleum in the UKCS in the Crown, and has historically granted regulation responsibility to the Secretary of State for the Department of Energy and Climate Change (DECC). DECC has most recently been the body responsible for the regulation of the oil and gas industry. However, a number of changes have been introduced following the specially commissioned review headed by Sir Ian Wood (the Wood Review), most significantly the creation of a new regulator – the OGA. The OGA has been established as an independent regulator by the Energy Act 2016. The OGA has inherited the licensing powers from DECC and will be the body responsible for the licensing rounds, issuing licences and granting licence assignment consents going forward. The Secretary of State's powers have been reduced to cover offshore environmental regulation, decommissioning and overall energy policy. HM Treasury retains control of fiscal matters, and HM Revenue & Customs retains responsibility for tax retrieval. Pursuing a more collaborative approach to industry regulation in line with the Wood Review’s recommendations, the OGA will adopt all other roles, having four times the personnel of DECC’s licensing division, a higher budget and extended powers to resolve disputes, attend operating committee meetings, access and publish data, and impose heavy sanctions. The OGA's regulatory and sanctions powers are discussed further in Section IX, infra.

The OGA now has the sole authority to grant licences for the exclusive right to search, bore for and extract petroleum in the territorial waters of the United Kingdom and on the UKCS, but the method of obtaining a licence remains largely the same (see licensing section below). Licences may also be acquired through asset transfers between companies, and the OGA consent is required prior to any licence assignment. The terms and conditions of a licence (known as model clauses) from the Petroleum Licensing (Production) (Seaward Areas) Regulations 2008 are now fully incorporated into offshore production licences. The model clauses set out in detail the conditions for the licence including term, licence surrender, record-keeping, working obligations, appointment of an operator, measurements and pollution. In awarding licences, the OGA must also comply with the Hydrocarbons Licensing Directive Regulations 1995 which set out additional anti-discrimination rules that EU Member States must follow when issuing petroleum licences.

In addition to regulatory requirements, there are several voluntary industry-based codes of practice to which UKCS licensees are expected to adhere. For example, the Infrastructure Code of Practice is intended to facilitate access by a third party to oil infrastructure in the UKCS such that the parties involved can agree fair and reasonable terms. The fallow acreage initiative places pressure on licensees to deliver activity on old licences where companies have not been active for some time, or to relinquish licences in order for the acreage to be offered...
to other companies. With respect to transfers of licences, the Commercial Code of Practice establishes an agreed framework to minimise resources spent on negotiations and promote positive commercial behaviour.

ii Treaties

The United Kingdom is a signatory to a number of international treaties and multinational agreements that have an impact on UK oil and gas regulation. Among the most important are the 1958 Geneva Convention on the Continental Shelf and the 1982 United Nations Convention on the Law of the Sea, which together set the limits for a state’s territorial sea and continue to govern the UK’s access to its Continental Shelf and beyond. Also significant to the oil industry is the Energy Charter Treaty, which regulates between Member States a number of energy-specific areas such as competition, transit of energy goods, trade, investment and dispute resolution. Other notable multinational agreements include the 1998 Convention for the Protection of the Marine Environment of North East Atlantic (OSPAR), which has had a significant impact on the United Kingdom’s decommissioning regulations.

III LICENSING

The OGA is the relevant licensing authority for offshore acreage. Regulation is by a licensing regime rather than a production sharing arrangement.

During a formal licensing round (usually annual), the OGA invites applications for specific acreage known as blocks or part-blocks pursuant to the Hydrocarbons Licensing Directive Regulations 1995. Licensing rounds are advertised online and in the European Journal. All applications are made in a prescribed form and companies applying for a licence must be registered in the United Kingdom, either as a company or as a branch of a foreign company. The timing for the application will vary depending on the size of the licensing round. In the simplest case (out-of-round with no environmental complications) it can take less than three months from the application. However, in a large licensing round with many licences and applicants it can take up to two years.

A company will make (either by itself or as part of a joint venture) an application for a specific licensed area. Applications will be considered individually and awarded by the OGA using a published assessment matrix. Licences are not awarded to the highest bidder. The primary focus of the OGA is on the extent of proposed work programmes and applicants must demonstrate financial and technical capability to complete such work programmes. The OGA will then publish a summary of successful bidders’ marks and work obligations. Once a licence has been granted, progression through the licence phases is dependent on obtaining OGA consent, which is also required for carrying out drilling, development and cessation of production activities.

There are currently two types of offshore licence awarded by the OGA: the exploration licence and the production licence. Under a seaward petroleum exploration licence, seismic surveys and shallow drilling can be performed in certain acreage. Other parties may hold an exploration licence over the same area, and it is, therefore, a non-exclusive licence. Under a seaward petroleum production licence, the licensee is granted the exclusive right to search, bore for and extract hydrocarbons from the UKCS in the area prescribed under the terms of the licence for the full life of the field from the exploration phase and development to decommissioning.
Three subcategories of production licence exist. The most common of these is the traditional licence. Potential applicants must be able to demonstrate financial, technical and environmental capability in order to be successful. The promote licence (introduced in 2002) is designed to award smaller companies production rights and allow a two-year period in which to obtain the requisite financial and technical capabilities prior to development. The frontier licence (introduced in 2003) recognises the difficulties in sourcing oil in remote areas of the UKCS (such as the deep waters west of Shetland) and permits screening over a large area to look for a wide range of prospects.

A licence will expire automatically at the end of each term, unless certain conditions allowing the licensee to advance to the next term have been fulfilled.

The duration of a traditional production licence is presently split into successive terms of four, four and 18 years. To progress from the initial to the second term, the licensee must have completed a work programme as approved by the OGA and relinquished a minimum of 50 per cent of the acreage under the licence. If, during the second term, the OGA has approved the development plan and all of the acreage outside that development has been relinquished, the licence may continue into the third term. The OGA may exercise its discretion to extend the third term beyond the prescribed 18-year period if production is ongoing.

The OGA also has powers to revoke any licence at an earlier stage than the expiry of its term. Such powers can be invoked in a number of circumstances such as insolvency of the licensee, breach or non-observance of the licence terms or if a licence assignment is carried out without prior approval from the OGA.

IV PRODUCTION RESTRICTIONS

The Energy Charter Treaty (ECT) requires the United Kingdom to take measures to facilitate oil transit across its national boundaries in a non-discriminatory manner and according to the principles of freedom of transit, namely, without distinction as to the origin, destination or ownership of the oil and on the basis of non-discriminatory pricing.

Offshore pipelines require the approval of the OGA, and in granting approval the OGA will have regard to the interests of other users of the sea for the transport of oil as well as the impact on the environment. Transportation of oil by road and rail is regulated by the Carriage of Dangerous Goods and Use of Transportable Pressure Equipment Regulations 2009, and is monitored by the Health and Safety Executive. Transportation of oil by sea is regulated by the Merchant Shipping (Prevention of Oil Pollution) Regulations 1996 and the Merchant Shipping (Dangerous Goods and Marine Pollutant) Regulations 1990. The International Maritime Dangerous Goods Code contains internationally agreed guidelines on the transport of dangerous goods.

Crude oil and crude oil products in the United Kingdom are not subject to a mandatory price-setting regime. The United Kingdom adopts a free-market approach, and oil and oil products are therefore priced and valued accordingly. There is no legal requirement to sell to domestic markets.

V ASSIGNMENTS OF INTERESTS

Government consent is required for assignments of a licence. A licensee may not, except with the consent of the OGA and in accordance with the conditions (if any) of the consent, do anything whatsoever whereby any right granted by the licence becomes exercisable
by or for the benefit of another person. The OGA operates an e-licence administration system (the Petroleum E-Licensing Assignments and Relinquishments System (PEARS)) for the submission of licence assignment applications for offshore production licences. The timing for consent depends on such factors as the complexity of the assignment, the quality of information initially provided by the licensee via PEARS and the number of other applications being processed. In addition, as part of a general drive towards improvement of the quality of records, each application will be checked for consistency between its starting point and the records of the licence’s current position. The first time each licence is subject to a PEARS application, the user will have to confirm such consistency. If confirmation cannot be given, the relevant licensee must notify the OGA via the system about any discrepancies, upload supporting documentation for the OGA to consider, and, if appropriate, implement a correction, which can also affect timing. A straightforward assignment will normally be processed in 10 working days, although this cannot be guaranteed. Production operatorship and financial checks in particular can take longer than this; the overall processing time will increase to 25 to 30 days where (straightforward) financial checks are involved. A small fee is required to be paid up-front for applications through PEARS.

With regard to transfers of shares in a company, the model clauses provide that the Secretary of State may ultimately revoke the licence on a change of control of the licensee, so parties often apply for reassurance that it is not the Secretary's intention to do so. When considering an application for a change of control the OGA's policy requirement is that the licensee must demonstrate that the change will not prejudice its ability to meet its licence commitments, liabilities and obligations. Where a licensee is dependent upon the financial support of its current corporate parent to enable it to meet its licence obligations and will become reliant upon the financial support of its new corporate parent, the OGA will require a parent company guarantee from the new corporate parent to replace any existing parent company guarantee that may have been issued. The OGA is generally willing to consider such requests. There are no pre-emptive rights reserved to the government.

VI  TAX

The United Kingdom does not itself participate in the petroleum sector, other than in its capacity as regulator, but does benefit from the industry through its tax regime.

There are three elements of taxation to which companies in the oil industry may be subject: petroleum revenue tax (PRT) (now effectively abolished, see below), ring-fence corporation tax (RFCT) and a supplementary charge (SC). HM Revenue & Customs Large Business Service – Oil and Gas Sector (formerly the Oil Taxation Office) administers the taxation regime.

i  PRT

PRT was a field-based tax charged on the profits arising to each participant from the production of oil under a licence. The PRT rate was permanently set to zero per cent in 2016 Budget, but it has not been abolished to allow for losses (e.g., suffered in the course of decommissioning of PRT-paying fields) to be carried back against past PRT payments.

ii  RFCT

Oil companies are subject to corporation tax, but there are a number of variations to the usual rules, including the ‘ring-fence’ mechanism. The ring-fence rules are designed to
prevent losses from other activities being set off against profits from oil and gas extraction by treating ring-fenced activities as a separate trade. However, it is possible to carry forward or back ring-fence losses against other activities. The applicable rates of tax are currently 20 per cent for non-ring-fenced profits and 30 per cent for ring-fence profits.

Despite the continuing cut in the main rate of corporation tax (from 26 per cent in 2011 to 20 per cent in 2015 announced in the 2013 Budget), the rate will remain at 30 per cent for profits from oil extraction in the United Kingdom.

iii SC

Introduced in April 2002, the SC constitutes an additional charge on ring-fenced profits (calculated in the same way as RFCT) without any deduction for financing costs. Costs that have been deducted for the purpose of paying corporation tax must be re-added before computing the SC liability. The SC is paid and administered at the same time as corporation tax. The current SC rate of 10 per cent (previously 20 per cent) has been introduced in the 2016 Budget as part of a major overhaul of the North Sea tax regime in response to the financial strain facing the sector.

Legislation was introduced in the Finance Act 2012 that effectively provides for a cap on the tax relief available for SC purposes for decommissioning costs. This restricts the use of SC losses arising as a result of expenditure incurred in connection with decommissioning to 20 per cent for decommissioning carried out on or after 21 March 2012.

VII ENVIRONMENTAL IMPACT AND DECOMMISSIONING

The implications of environmental incidents and drilling or production-related emissions have seen an increase in environmental regulation in the United Kingdom in recent years, particularly since the Gulf of Mexico oil spill in 2010.

i Offshore Safety Directive

The United Kingdom has recently seen a change to environmental regulation following the European Offshore Safety Directive (OSD), which came into force in July 2013. As a result, the offshore environmental, health and safety regime in the United Kingdom is in a state of transition, with new implementing legislation introduced in July 2015. UKCS operators are affected by a number of changes as a result, particularly in relation to oil pollution emergency plans (OPEPs) and environmental permitting.

An OPEP is an emergency response document that will facilitate the implementation of a robust and effective response to an oil pollution incident and minimise the impact on the marine environment. The Merchant Shipping (Oil Pollution Preparedness, Response and Co-operation Convention) Regulations 1998 require that all operations carried out on or in relation to an offshore installation or pipeline (including decommissioning) which may present a risk of marine pollution by oil must be the subject of an approved OPEP. However, following the amending regulations in 2015, the category of ‘responsible persons’ tasked with owning, maintaining and implementing an OPEP has been extended to include ‘installation operators’, ‘well operators’, ‘pipeline operators’ and owners of non-production installations (such as drilling rigs). Other regulatory approval and consent will be withheld until the OPEP is approved.

The matter of who will now be responsible for holding environmental permits offshore is also a significant change and affects the dynamic of offshore environmental liability. While
previously the Secretary of State had the power to take action against a third-party duty-holder (such as a contractor operating a facility on behalf of the licensee) for pollution incidents, the reality was that environmental permits were typically held by the operator/licensee, and it would be the primary target. However, recent statements made by the OGA now indicate that they expect the permit holder to be the owner of the safety case, as ‘the person in control of day to day operations’, rather than the licensee (if different). The default position is now expected to be that, as the permit holder, the health and safety duty-holder will now be the primary target for enforcement action. As such, while liability for environmental and economic damage and financial security requirements will remain with licensees, criminal liability under environmental regulations for breaches (typically discharges in breach of the terms of a permit) will rest primarily (but not entirely) with permit holders, e.g., installation and well operators, and including drilling contractors and non-licensee duty-holders.

Article 4 of the OSD also requires Member States to ensure that decisions on granting or transferring licences take into account the capability of a licensee to meet the financial and technical requirements of the OSD. This provision was transposed into UK national law by the Offshore Petroleum Licensing (Offshore Safety Directive) Regulations 2015, which requires licensees, for the duration of offshore petroleum operations, (1) to make adequate provision to cover liabilities that potentially derive from those operations (2) to maintain sufficient capacity to meet all the financial obligations that may result from any liability for offshore petroleum operations carried out by operators appointed by or in respect of it.

Other relevant regulations
Permits may also be required under a range of other regulations. The Offshore Chemicals Regulations 2002 (as amended in 2011) and the Offshore Petroleum Activities (Oil Pollution Prevention and Control) Regulations 2005 (as amended in 2011) set out the regulatory framework for use and discharge of offshore chemicals and for the prevention and control of oil pollution, including permitted discharges in accordance with the conditions of the relevant permits. These regimes were extended in 2010 to installations used for the offshore storage of natural gas, offshore unloading of liquefied natural gas and the offshore storage of carbon dioxide for the purpose of its permanent disposal.

The Offshore Petroleum Activities (Conservation of Habitats) Regulations 2001 (as amended in 2007), apply to oil and gas activities carried out wholly or partly in the UKCS. Together with the Offshore Marine Conservation (Natural Habitats &c.) Regulations 2007 (as amended in 2012), the regulations implement the Habitats Directive (92/43/EEC) and the Wild Birds Directive 2009/147/EEC. These Regulations apply in the offshore area (beyond 12 nautical miles from the UK coast) and offer protection to marine life by creating a number of offences that aim to prevent environmentally damaging activities. The Conservation (Natural Habitats &c.) Regulations 1994 and the Wildlife and Countryside Act 1981 may also have relevance to offshore activities in territorial waters.

There is also a framework of regulations governing offshore atmospheric emissions that relate to the flaring of gas, diesel engines, gas turbines and other ‘combustion plant’. The Offshore Combustion Installations (Prevention and Control of Pollution) Regulations 2013 came into force on 19 May 2013 in order to implement the Industrial Emissions Directive (Directive 2010/75/EU) and superseded the equivalent 2001 Regulations, subject to transitional provisions. The regulations require permits to be put in place and complied with for offshore combustion installations with a thermal input of 50MW. As regards waste, waste disposal licences and a waste management plan must also be put in place.
The Fluorinated Greenhouse Gases Regulations 2015 similarly provide for regulations relating to plant and equipment with potential for the emission of F-gases on an offshore installation. Flaring and venting consents are required under the Petroleum Act 1998 and will be granted by the OGA. Waste disposal licences and a waste management plan must also be put in place. The United Kingdom is also part of the EU Emissions Trading Scheme and a Greenhouse Gas Permit must be held in order to operate. These regulations require annual reporting to the regulator on greenhouse gas emissions from the installation.

iii Onshore regulation

Environmental regulation onshore is a dynamic area. Environmental permits are required under the Environmental Permitting (England and Wales) Regulations 2010. In Scotland, the Pollution Prevention and Control (Scotland) Regulations 2012 implement a similar permitting regime. Permit conditions cover emissions to land, air and water and require operators to use best available techniques to prevent and minimise emissions. Emissions from onshore large combustion plants are also regulated under these Regulations. Separate consents or registrations may be required depending on the nature of the activity for matters such as use and disposal of radioactive substances and the disposal or carriage of waste.

Separately, the contaminated land regime under the Environmental Protection Act 1990 and subsidiary regulations is an administrative regime requiring the polluter (or, in its absence, the owner or occupier of land) to pay for remediation. The Environmental Damage (Prevention and Remediation) (England) Regulations 2015 in England and equivalent regulations in Wales and Scotland implement the EU Environmental Liability Directive (2004/35/EC) (Environmental Liability Directive) onshore, requiring the responsible operator to remediate damage to the environment or where this is impossible, to make compensatory payments.

iv Environmental liability and OPOL

In the event of a significant oil spill the operator must implement its emergency response centre to take appropriate actions to prevent further pollution and implement a response strategy. In the event of an oil leak in UK waters, the licensees will have unlimited liability for all costs of remediation under the Environmental Liability Directive, and, if negligence can be proven, will also have unlimited liability to those affected by their actions. There is also an element of strict liability for remediation costs and direct damage under the rules of the Offshore Pollution Liability Association Limited (OPOL). This is a voluntary scheme but in practice all operators are required by the OGA to be members of OPOL. This requires operators to have financial assurance, usually in the form of insurance, against pollution liabilities. They are required to compensate public authorities and third parties affected by pollution on a strict liability basis up to the limits of liability under the OPOL scheme (currently US$250 million per incident). If any member defaults, ultimately the other members are required to make good the default, up to the same limits of liability.

Breach of any environmental and health and safety regulations is a criminal offence. Recent sentencing guidelines for England and Wales for specified environmental offences, requiring sentences to reflect the level of harm, level of culpability and turnover of the offender, facilitate a dramatic increase in fines in many circumstances. The Court of Appeal has commented that for large organisations fines could be millions of pounds. For other
offences not covered, owing to changes in sentencing powers for the lower courts, sentences are also expected to increase. No equivalent guidelines exist in Scotland, but a sentencing council that would issue such guidelines is under consideration.

v Competent authorities

The enforcing authorities for environmental matters in the United Kingdom are DBEIS, the newly established Offshore Safety Directive Regulator (OSDR), the Environment Agency (EA) and the Scottish Environmental Protection Agency. The Maritime and Coastguard Agency (MCA) is the competent UK authority in terms of counter-pollution measures and response at sea, and the Joint Nature Conservation Committee (JNCC) and Marine Scotland provide advice on environmental sensitivities that may be affected as a result of any oil spill. Both the MCA and JNCC are consulted as part of the OPEP review and regulatory approval process.

vi Decommissioning

With respect to decommissioning, domestic UK legislation has adopted a number of international and regional treaties, including UNCLOS (Law of the Sea Convention) Article 60(3), IMO Guidelines and Standards 1989 and 1992 OSPAR Convention (Recommendation 2006/05 was adopted by the 2006 OSPAR Commission, which introduced a management regime for offshore drill cuttings piles).

Under Section 29 of the Petroleum Act 1998, the Secretary of State is empowered to serve notice on a wide range of persons indicating that those persons are jointly and severally liable to carry out an approved decommissioning programme. In the first instance this would include parties to joint operating agreements for installations and owners for pipelines. The notice will either specify the date by which a decommissioning programme for each installation or pipeline is to be submitted or, as is more usual, provide for it to be submitted on or before such date as the Secretary of State may direct. Primary liability rests on the parties to the asset at the time of decommissioning. The Secretary of State may withdraw a Section 29 notice, for example, on the sale of an asset. This right used to be automatic, but is now less so. However, the Secretary holds a significant ‘clawback’ power under Section 34, whereby the liability net can be expanded to include anyone on whom a Section 29 notice could have been served at any time after the first Section 29 notice is served (i.e., former owners – even those who have previously had the Section 29 notice withdrawn – and affiliates of such owners).

Typically, parties contractually agree to provide security for their share of decommissioning liabilities as part of a sale and purchase, or as part of a field agreement with co-venturers, or, on rare occasions, as part of an agreement with the government. The amount of security, which is recalculated each year, is based on an estimate of the decommissioning cost net of the remaining value in the field. The usual form of security is a parent guarantee or letter of credit. The proceeds are paid to a trustee if the licensee defaults or is insolvent or does not renew the credit, meaning that a fund will be available to meet decommissioning costs.

Tax relief is available for decommissioning costs when they are incurred and under the Finance Act 2013 the UK government guarantees the present rates of tax relief to individual companies investing in the North Sea by entering into Decommissioning Relief Deeds. Under these contracts, if the tax relief regime is changed, the government will make a compensatory payment to the affected companies.
VIII FOREIGN INVESTMENT CONSIDERATIONS

i Establishment
Companies may only perform exploration and production activities in the United Kingdom under a petroleum licence. All companies applying for a licence must be registered in the United Kingdom, either as a company or as a branch of a foreign company (in order to effectively have a taxable UK presence). The OGA will consider each application on a case-by-case basis and will require a company to demonstrate its financial worthiness (i.e., that it is able to finance its share of the relevant work programme for the licence in question) and technical capability.

Companies wishing to be appointed as operator are considered against additional criteria including previous experience, technical expertise and environmental awareness.

While there is no specific limitation to foreign companies, the Secretary of State has the power to make a public interest assessment of the impact of a foreign company on the market. Furthermore, the Secretary requires that to be a licensee, a company must have a place of business within the United Kingdom. In assessing the suitability of a candidate to act as an operator, the Secretary has stated that the location of the company’s operations may be a factor in assessing its ability to run operations effectively.

A branch presence or company incorporation can be set up relatively quickly and cheaply (within a day if required).

ii Capital, labour and content restrictions
From a European perspective, as a member of the EU, EEA nationals are permitted to live and work in the United Kingdom without being discriminated against on the basis of nationality (although there are special rules for Croatian nationals for visa purposes). All non-EEA nationals must obtain permission to work in the United Kingdom. Those working purely offshore are exempted from this requirement. In order to sponsor an employee to work in the United Kingdom, an employer must be licensed to do so by UK Visas and Immigration. Penalties for non-compliance include civil penalties of £20,000 per illegal worker or unlimited fines or imprisonment for knowing non-compliance.

Once it has been ascertained that an individual has the right to work in the United Kingdom, they also have the benefit of the Equality Act 2010, which provides that employers are prohibited from discriminating against them on various grounds including race (where race includes colour, nationality and ethnic or national origins). The scope of this protection is wide, and includes the management of recruitment, terms of employment or engagement, access to job opportunities and benefits, and termination. If an employer is found guilty of discrimination under this Act, it could be liable for unlimited compensation arising from the discrimination, including an award for injury to feelings. An employment tribunal’s powers to make recommendations regarding the operations of the employer (e.g., training on equal opportunities) and increase compensation for subsequent non-compliance have been removed with effect from 1 October 2015.

iii Anti-corruption
The Bribery Act 2010 came into force on 1 July 2011, introducing significant changes to the anti-corruption law in the UK. Section 7 of the 2010 Act provides for a new strict liability corporate offence, committed when a commercial organisation fails to prevent bribery by a person associated with it. For a commercial organisation to be guilty of an offence
under Section 7 it does not matter if the associated person is convicted of an offence. The prosecution need only prove beyond reasonable doubt that an offence has been committed and that the bribe was made to benefit the commercial organisation. If this is not proved, there is no offence pursuant to Section 7. If this is proved, the commercial organisation must demonstrate that adequate anti-bribery procedures were in place on a balance of probabilities. It also does not matter whether the organisation is aware of the corrupt conduct or not. The intention of the associated person offering the bribe is, however, important. A Section 7 offence will only be committed if the associated person had an intention to obtain, retain or advantage the business of the commercial organisation.

A commercial organisation can be fined an unlimited amount if a Section 7 offence is committed. The sentencing guidelines in respect of bribery offences provide that the court should determine a level of fine that reflects the seriousness of the offence while taking into account the financial circumstances of the offender. The level of fine may then be adjusted in light of other relevant factors that merit such adjustment. The guidelines provide that court’s aim should be to achieve (1) removal of all gain by the organisation committing the offence; (2) appropriate additional punishment; and (3) deterrence.

The investigations under the 2010 Act are conducted by the Serious Fraud Office, an independent government department responsible for prosecuting serious and complex fraud, bribery and corruption. The first commercial organisation was convicted under Section 7 of the 2010 Act in February 2016 and ordered to pay a fine of £2.25 million.

Following the enactment of the 2010 Act, amendments were made to Clause 22 of the Oil & Gas UK Industry Model Form Joint Operating Agreement (JOA) to address the 2010 Act. The Clause has been adapted to include anti-bribery provisions warranting that the JOA participants have not, nor will, bribe in connection with the JOA, the licence or joint operations and to provide that participants and their affiliates must devise and maintain adequate internal controls and steps should be taken to ensure such controls are imposed on contractors.

IX CURRENT DEVELOPMENTS

i The OGA and MER UK

A new independent regulator – the OGA – has been established by the Energy Act 2016. On 1 October 2016, the OGA became a government company and all the regulatory powers envisaged by the Energy Act vested in the OGA. The OGA is responsible for effective stewardship, regulation and licensing of the UKCS and also for facilitating maximum industry collaboration in respect of exploration, development and production in order to achieve the principal objective of maximising economic recovery of petroleum from the UKCS (MER UK).

The Energy Act confers on the OGA a number of powers it will need in order to act as a robust regulator. Among the most important ones are the power to act on its own initiative to issue non-binding recommendations in relation to relevant disputes between the operators and to have such disputes referred to them; the power to attend meetings the content of which is relevant to MER UK; and the power to impose sanctions for breach of ‘petroleum related requirements’ (in effect, non-compliance with MER UK).

The new regulator will use additional powers to facilitate implementation of the MER UK strategy. However, such new powers are only intended to enable stronger and better stewardship rather than to introduce more bureaucracy. The Wood Review considers that
the development of the UKCS must continue to be driven by operators but that the new regulator should have the requisite skills, experience and authority to influence and guide parties.

The new regulator should also develop and implement important sector strategies in respect of the following – exploration (including access to data), asset stewardship (including production efficiency and improved oil recovery), regional development (starting with the southern North Sea), infrastructure, technology (including enhanced oil recovery and carbon capture and storage) and decommissioning.

ii Brexit – the UK’s decision to leave the European Union

On 23 June 2016, the people of the United Kingdom voted in a referendum to leave the European Union, setting in motion the long and arduous process of disentangling the UK from the European laws, regulations and institutions. Some parts of the UK oil and gas framework discussed above flow directly from the UK’s membership in the EU and the common market. As the UK sets out on its own on the uncharted waters of post-Brexit life, it is not unthinkable that with time the relevant laws prescribed by the Union law (in the areas such as employment, environmental protection, and health and safety) may be amended.

However, there is no indication that Brexit will have an immediate impact on the North Sea industry in the short term. Much of the core regulation governing oil and gas operations (such as taxation and licensing) is of UK origin and there may be little, if any, political will to repeal laws based on EU legislation that have already been implemented into domestic law (although some saving legislation may require to be enacted to preserve the relevant provisions).

Charting possible outcomes and scenarios to follow Brexit involves an exercise of crystal ball gazing. Much depends on the outcome of UK–EU negotiations. On one hand there is a risk of reduced inward investment and flight of capital from the sector. Following the Norway-style model may not be possible without access to the common market. In the same vein as Norway, the UK may be required to comply with European climate change regulation to preserve diplomatic ties, but without being able to influence it. On the other hand, Brexit could support inward investment as a result of a weakening pound. The government may also be incentivised to increase its support for the industry to allay sector’s instability fears that ensued following the vote.

Whatever the future brings, it is too early to draw conclusions at this juncture, and the post-Brexit developments and their impact on the UK oil and gas industry remain a key area to watch in the coming years.
APPENDIX 1

ABOUT THE AUTHORS

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Fariz Abdul Aziz is a partner in the corporate department of Skrine. Fariz’s main area of focus is on cross-border mergers and acquisitions, energy, oil and gas, takeovers, private equity investments, and corporate restructurings. He has represented a number of leading foreign multinationals on their inward bound transactions and divestments. Fariz has also recently been advising Malaysian entities on their outward investments. Fariz previously served as a facilitator for the Prime Minister’s Department’s Performance Management and Delivery Unit’s (PEMANDU) Corridors and Cities Lab covering the Manufacturing and Oil, Gas and Petrochemical Entry Point Projects in Malaysia’s East Coast Economic Region. This project forms part of the government of Malaysia’s Economic Transformation Plan, which aims to make Malaysia a high-income nation by 2020.

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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, Edmonton, 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.

Ferdinand’s interest is in corporate law covering areas of investment law, construction law, commercial law and international trade particularly the ECOWAS regime relating to investment and doing business in the sub-region. He currently leads the firm’s procurement, PFIs, PPPs and infrastructure, and energy, mining, oil and gas practices. He is also recognised as a leading lawyer in procurement and energy by Who’s Who Legal.
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Laura Alakija is partner on the commercial transactions and confidential documentation desks of Sterling Partnership. She has acted for oil companies in due diligence and asset acquisition, including business entry, regulatory compliance and licensing and permits. She has also worked with companies in the power sector in providing transaction support for gas to power projects. Apart from energy, Laura has worked on a number of commercial transactions in infrastructure and real estate, information and communication technology, the automotive industry, business start-ups and confidential documentation covering wills, trusts and other confidential arrangements and instruments for both individuals and corporates.

Laura has an LLM in transnational oil, gas and energy law from the University of Derby, UK. She joined Sterling Partnership in June 2010 and was member of faculty of the Centre for Law and Business, a registered centre of the University of London International Programmes from 2009 to 2010.

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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 (MCIArb) of the Chartered Institute of Arbitrators (UK and Nigerian Chapter).

Prior to joining Sterling Partnership in 2010, Israel was in-house in Shell Nigeria for over a decade. While in 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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Manus Booysen is a partner and head of the mining, energy and natural resources practice of Webber Wentzel. He holds the degrees BA, LLB and MBA from the University of Pretoria. He served on the Minerals Committee of the International Bar Association’s section on engineering, energy and resources law.

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He is an accomplished international speaker on the topics of mining law.

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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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James Comyn is a partner in Shearman & Sterling LLP’s London office. Between 2009 and 2016, he was based in the firm’s Abu Dhabi office, where he served as office managing partner. James advises many of the region’s government-owned entities on transactions with foreign partners and has also advised foreign investors on their investments in the countries of the Arabian Gulf, particularly in the oil and gas sector.
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With 19 years of experience providing legal and regulatory advice to private companies, government agencies and state-owned corporations throughout Mozambique, Pedro Couto is involved in initiatives such as BOT, BOOT, corporate restructuring, foreign investment, project financing, privatisation and public tenders in areas of transport, mining, aviation, energy, oil and gas, port, rail and commercial infrastructure. He has a solid understanding of financial, exchange control and tax legislation in Mozambique and has worked both at the municipal and national levels providing input into legislation and regulatory frameworks.

He has further worked for several governmental agencies, including: the Ministry of Environmental Affairs assisting with the establishment of toxic waste sites, the Ministry of Tourism for the preparation of the concession tender process of the National Park of Limpopo, and the National Roads Administration in its major public works contracts.

In the private sector, Pedro Couto has been involved in the negotiations of several PPPs, namely with the concession of the Port of Maputo; the concession of the Railway and the Port of the Nacala Corridor; and the concession for the Ressano Garcia Power Project.

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

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Paulo Ferreira has six years of litigation experience in civil, commercial, labour, administrative and arbitration fields. He joined the energy, natural resources and infrastructure department in June 2011 and has been active in the areas of oil and gas, energy, infrastructure, mines and natural resources.

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Telmo Ferreira has 18 years of experience in the corporate world and is currently CGA’s managing partner, also in charge of mergers, acquisitions, capital markets and tax. His expertise has been crucial for the legal viability and success of some of the major transactions involving companies operating in key economic sectors. That includes, among others, advising mergers and acquisitions on the banking and industrial sectors, listing of companies, IPOs, corporate governance and commercial, financing and concession contracts in various sectors. Recently he has been involved in some of the most relevant concessions in Mozambique in the mining and oil and gas sectors.

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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”.’

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Manfred has been working in the energy sector for nearly 10 years and has been taking on various positions in legal departments. Currently he is head of legal in OMV Gas Marketing & Trading GmbH, a member of the OMV Group. OMV Gas Marketing & Trading GmbH is Austria’s leading gas supplier to distributors and business customers.

Manfred has 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
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Manfred will take on new challenges in the upstream oil sector within OMV Aktiengesellschaft at the end of 2016. Manfred is a trained mediator specialised in energy disputes.

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Yannis Kourniotis is head of the energy, natural resources and environmental department and joint head of the project finance and PPPs department at M&P Bernitsas Law Offices. He has extensive experience in the area of project finance, with a focus on infrastructure and energy projects, as well as public private partnerships. He acts for governments, sponsors and lenders on transport, health, education, renewable and thermal energy projects as well as transactions involving concessions granted by governments to private developers. Yannis’s expertise includes the drafting and negotiation of concession, partnership, long-term lease, project and financing agreements. He also advises on public tenders and the assignment of public contracts, in particular on the regulatory requirements for developing projects and public private partnerships in Greece. Yannis has considerable experience of representing clients in the privatisation, merger and acquisition of oil, gas and utility companies, as well as the acquisition by foreign and local investors of renewable energy project development companies.

Yannis holds a law degree from the University of Athens, Greece, an LLM degree in European Union Law from the University of Leicester and an MBA from the University of Strathclyde Graduate Business School, Glasgow.

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Roberto regularly assists Italian and foreign clients, ranging from medium-sized companies to large multinational groups, in a wide range of matters relating to commercial contracts, corporate and M&A as well as litigation, with specific reference to the energy and natural resources sector, including oil and gas and renewable energy.

Roberto provides advice on all aspects of the oil and gas field, both in Italy and internationally (including, acquisition and disposal of assets, joint ventures, supply and services agreements, storage, contracts relating to the relevant facilities and infrastructures, regulatory matters and dealing with the competent public bodies, litigation including before administrative courts and arbitration).

After graduating *cum laude* from the LUISS University of Rome he obtained a master’s degree from the University of Bari and was admitted to the bar in 1992. He has been a research fellow of private law at the University ‘La Sapienza’ in Rome.

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His principal practice areas include energy law, project finance, corporate law, mergers and acquisitions, civil and commercial contracts, administrative law and public contracting.
Mr Mateo joined Barrera, Siqueiros y Torres Landa, SC (now Hogan Lovells BSTL, SC) in 2005. In 2010 he worked as a summer associate in the Aberdeen offices of the British law firm CMS Cameron McKenna, advising companies in energy projects (primarily hydrocarbons) in the North Sea.

Mr Mateo has been actively involved in upstream and downstream energy projects, from oil and gas exploration and production projects to power and natural gas infrastructure deals. He has advised companies such as Pemex, Apache Corp, Seadrill, Dowel Schlumberger de México, Statoil, British Gas and Exterran.

In 2011 Mr Mateo was part of the legal team advising PMI in its association with Petrofac and Schlumberger in the first round of exploration and production of integral services contracts tendered by Pemex.

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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, including a set-up regarding the sale of virtual power. 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. Michael Meyer has also acted as lead counsel in the divestiture and merger of activities in the electricity sector and for the Swedish energy incumbent Vattenfall AB in the divestiture of two natural gas-fuelled combined power and heating plants together with the attaching heat transmission lines. Further, Michael Meyer was involved in the establishment of the joint venture between Vestas Wind Systems A/S and Mitsubishi Heavy Industries.

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.

Natalya is recognised in Chambers Global, Energy and Natural Resources (Russia); 2016, Legal Media Group’s (Euromoney’s) Expert Guide to the World’s Leading Energy and Natural Resources Lawyers, 2016, The Legal 500 for energy and natural resources law in Russia, 2005–2016. She has been co-administrative and managing partner of the Vinson & Elkins’ Moscow office since 2004.

CONSTANCE OKHILUA

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Constance Okhilua is a senior associate in the energy, commercial transactions, corporate law and commercial dispute resolutions units at Sterling Partnership. Her representation of clients spans various aspects of commercial dispute resolution, legal advice and transaction documentation as well as company secretariat and regulatory compliance support.

ESTHER ONOJI

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Esther Onoji is a senior associate in Sterling Partnership’s energy and natural resources, and corporate and commercial law departments. Outside of her work in energy and natural resources, she has also worked in our corporate law group providing regular advice to companies on regulatory compliance, business start-ups, corporate due diligence, commercial and real estate transactions, and corporate restructuring.

NICOLAS TH PAPACONSTANTINOU

Papadopoulos, Lycourgos & Co LLC

Nicolas Th Papaconstantinou is a partner in the real estate and energy department at the law office of Papadopoulos, Lycourgos & Co LLC, in Nicosia. He focuses his practice on real estate, wills and succession, energy and related litigation. He also deals with specialised transnational corporate and commercial matters.

Mr Papaconstantinou attained a BSc degree with honours in economics and politics at the University of Bath and, following postgraduate study at the London School of
Economics, a master’s degree in science in real estate economics and finance. In 2008, he graduated in law (LLB with honours) from City University, London. Drawing on his real estate, economics and finance background, he has added value to clients in several cases in his capacity as an advocate.

In 2013, Mr Papaconstantinou obtained a postgraduate diploma (PgDip) in oil and gas law at Aberdeen Business School of Robert Gordon University and he is currently studying towards a master of laws (LLM) in oil and gas law at the same institution.

Mr Papaconstantinou is also a certified real estate valuer registered with the Scientific Technical Chamber of Cyprus (ETEK). He was admitted to the Cyprus Bar in 2009.

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 Chambers Europe (Energy and Natural Resources, Russia 2014), Chambers Global (The World’s Leading Lawyers, Energy and Natural Resources, Russia 2014) and Who’s Who Legal of Energy Lawyers (2013–2014). 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.

MÁRCIO PAULO
CGA – Couto, Graça & Associados
Márcio Paulo has six years of experience in the corporate and banking practice. He joined the energy, natural resources and infrastructure department in December 2011 and has been active in the areas of oil and gas, energy, infrastructure, mines and natural resources.

BERTA DE MARCH
Cuatrecasas, Gonçalves Pereira
Berta de March has been an associate at Cuatrecasas, Gonçalves Pereira since 2012, having also spent a brief stint at Sal & Caldeira Advogados in Mozambique in 2015. Her practice focuses on civil and commercial litigation, and corporate law regarding oil, gas and mining operations. During her time in Mozambique, Berta published and co-authored several articles on oil and gas regulation in Mozambique.

ANA ISABEL MARQUES
Cuatrecasas, Gonçalves Pereira
Ana Isabel Marques joined Cuatrecasas, Gonçalves Pereira in 2005 as an associate. She is now a senior associate.

Her main practice focuses on administrative litigation and public law, particularly urbanism, town planning, environmental and regulatory law. In recent years, she has advised on projects involving town planning and monitored procedures relating to the construction, installation, management and operation of real estate developments in residential, commercial, industrial, logistic and tourist segments. She has also participated in environmental impact assessments and advised on gaseous emissions, waste management; and conducted audits on compliance with urban, environmental and regulatory rules.
CARLOS RAMOS MIRANDA
Hogan Lovells BSTL, SC

Mr Ramos has been a partner of Hogan Lovells BSTL, SC (previously Barrea, Siqueiros y Torres Landa) for over a decade. He received his law degree from the Instituto Tecnológico Autónomo de México in 1994 and his LLM degree from Georgetown University Law School (2004–2005). He obtained postgraduate diplomas in executive international finance from Georgetown University Business School (1995) and executive finance from the Ibero-American University (2004).

His principal areas of practice are project financing, energy law, water, insurance, and mergers and acquisitions.

Mr Ramos began his professional career as a summer intern at the firm Holland & Knight in 1993, after which he was with Dickstein, Shapiro, Morin & Oshinsky, LLP as an international associate from 1995 to 1996.

Mr Ramos was rated in Band 2 in energy and natural resources by Chambers Latin America: Latin America’s Leading Lawyers for Business, 2013. Also, Latin Lawyer 250 recommends him for his experience and expertise. Chambers Latin America recognised Mr Ramos as a leading individual in energy and natural resources. He was named one of the ‘40 under 40’ lawyers in Mexico by LatinLawyer magazine in 2003.

Mr Ramos was part of the legal team that advised Pemex on the design of their multiple service agreements. In 2011 Mr Ramos was part of the legal team advising PMI in its association with Petrofac and Schlumberger in the first round of exploration and production integral services contracts tendered by Pemex. Since 2012 he has been part of a multidisciplinary team advising Pemex Exploración y Producción in the design of the new exploration and production services contracts.

He has also been involved in the tender and structuring processes for more than 15 hydraulic infrastructure projects, for both water treatment and pipelines. He worked on a discount-financing scheme for Pidriegas projects worth over US$600 million, and their restructuring.

GARYN RAPSON
Webber Wentzel in alliance with Linklaters

Garyn Rapson is a partner in the project finance, construction and environment practice within the banking, projects and regulatory business unit at Webber Wentzel.

Garyn’s work is focused primarily in the energy, mining, oil and gas and industrial sectors. He has extensive experience in conducting due diligence investigations, environmental legal audits, regulatory work and transactional advice, in these sectors. His expertise extends to litigation in environmental matters and drafting representations against directives and compliance notices.

In the oil and gas space Garyn has provided advice to clients such as Anadarko, PetroSA and Sunbird Energy on, inter alia, permitting requirements, potential environmental liability and the apportionment thereof for pollution events.

Garyn has degrees in science and law, as well as a master’s degree in environmental law.

DIOGO ORTIGÃO RAMOS
Cuatrecasas, Gonçalves Pereira

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.

**CHRISTOPH SCHIMMER**
*DLA Piper Weiss-Tessbach GmbH*

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 has worked as research and teaching assistant at the Institute for Tax Law at the University of Vienna.

**JOHN SMELCER**
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John is head of the oil and gas practice at Webber Wentzel.

He specialises in the development and financing of oil and gas projects across the value chain including unconventional upstream gas developments, large-scale liquefied natural gas financings and oil forward sale structures. He has taken a lead legal role on a number of the largest LNG project financings around the world, including in Qatar, Papua New Guinea and Australia. In addition, John has strong experience in the development and financing of downstream oil and gas projects, including refineries, gas-fired power projects, fertilisers and other petroleum-supplied industries. John's practice involves representing sponsors, governments and lenders (including commercial banks, export credit agencies, underwriters and DFIs) in all aspects of project development and the financing of those projects.

John holds a BA degree from Princeton University and a juris doctorate of law from the University of Washington.

**NANA SERWAH GODSON-AMAMOO**
*AB & David*

Nana Serwah is an associate partner at AB & David. Nana is a solicitor and barrister (qualified in Ghana) with significant experience is corporate law, energy, oil and gas, banking, finance and capital markets and public sector consulting. She has worked on various energy, oil and gas transactions and projects. 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 from University of Ghana and an LLM from Lazaski University, Poland.

**BEAT SPECK**
*Wenger & Vieli Ltd*

Beat Speck's practice focuses on the areas of the purchase and sale of companies (M&A), the establishment of headquarters in Switzerland, joint ventures and corporate governance, among others, in the energy industry. As attorney-at-law, notary public of Canton Zug and issuer's representative recognised by the SIX Swiss Exchange, he can efficiently offer the individual processes from one source.
CRAIG N SPURN
McCarthy Tétrault LLP
Craig N Spurn is a partner in and lead of McCarthy Tétrault’s oil and gas group in Calgary. He practises corporate and commercial law in the energy sector with an emphasis on oil and gas law, energy transactions and projects, including LNG projects and related pipelines. Mr Spurn is recognised by Chambers Global: The World’s Leading Lawyers as one of Canada’s leading lawyers in energy: oil and gas, by The Canadian Legal Lexpert Directory in the area of oil and gas, Who’s Who Legal of Business Lawyers as one of the world’s foremost legal practitioners in the oil and gas practice area, and by Best Lawyers in Canada in the area of natural resources law.

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.

MICHAEL TSCHUDIN
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Michael Tschudin specialises in competition law and regulated markets, in particular energy law. He advises clients in relation to public law and represents them before regulatory authorities.

Having worked at the Swiss Federal Administrative Court, which is the court of appeal for decisions taken by federal regulators, such as the Federal Electricity Commission, he is able to draw on this practical experience when advising clients.

PARIS TZOUMAS
M&P Bernitsas Law Offices
Paris Tzoumas is an associate at M&P Bernitsas Law Offices. He has experience in the area of project finance, focusing on oil and gas transactions, energy, environment and infrastructure projects. Paris advises sponsors and lenders on legal matters related to project structuring and development, financing, construction and other general contract issues, while he has experience drafting and negotiating project documents, sub-contracts, as well as, financing and security documents.

Paris holds a law degree from the University of Athens, Greece, a postgraduate degree (LLM) in civil (private) law from the same University and a postgraduate degree (LLM) in public law from the University College London (UCL), London.

JONATHAN VEERAN
Webber Wentzel in alliance with Linklaters
Jonathan is a partner and member of the oil and gas sector group at Webber Wentzel. He has expertise in transaction structuring in the mining and upstream oil and gas industries. In addition, he has advised on various large black economic empowerment mining transactions in South Africa and other African jurisdictions including Zimbabwe, Ghana, Guinea, Mozambique and Madagascar.
Jonathan advises various international companies (NYSE, LSE, ASX, TSX and AIM-listed) on their business activities in Africa and, in particular, the regulatory aspects of the mining and upstream oil and gas. He has extensive experience in developing structures that afford international investors protection under bilateral investment treaties as well as other instruments under international investment law.

Jonathan advised several mining companies and governments on the Extractive Industries Transparency Initiative’s international best practice models and contributed to the International Bar Association’s Model Mine Development Agreement Project. Jonathan served as co-counsel to the claimants in the matter of Piero Foresti and other v. the Republic of South Africa, which was heard in Peace Palace in The Hague. He also serves on the Webber Wentzel team that was appointed to advisory panel of the World Bank’s EI-TAF project.

KEITH VEITCH
Webber Wentzel in alliance with Linklaters

Keith Veitch graduated in commerce and started his career in South African exchange controls at the South African Reserve Bank in 1978. He moved into the commercial banking sector in 1978 and has consulted outside of the banking sector in the field of exchange control since 1986. Keith was a member of the Exchange Control Project Committee of the South African Institute of Chartered Accountants from the late 1990s until 2011 and is the author of a feature article on South African exchange controls for Accountancy South Africa. Keith has 38 years of experience and is a consultant for Webber Wentzel. His clients include leading South African, as well as international listed and unlisted companies and groups.

KENNETH WALLACE-MÜLLER
DLA Piper Weiss-Tessbach GmbH

Kenneth Wallace-Müller is a trainee solicitor in the projects and finance group at DLA Piper in Vienna, Austria, specialising in energy and infrastructure law.

PENELOPE WARNE
CMS

Penelope Warne is senior partner and head of energy at CMS.

She advises on a broad range of high-profile deals and transactions and oil and gas law and commercial work relating to the oil industry. She is an honorary fellow and trustee of the Centre for Energy, Petroleum and Mineral Law and Policy at Dundee University and a board member of IMD in Lausanne, Switzerland. Penelope set up the firm’s Aberdeen office in 1993. She has also set up offices in Edinburgh, Rio de Janeiro and Dubai. She writes a monthly energy column for the Press and Journal, an Aberdeen newspaper.

Penelope’s practice spans the globe, having advised the oil and gas industry in the North Sea, US, Norway, Brazil, MEA and Russia.

OSKAR WINKLER
DLA Piper Weiss-Tessbach GmbH

Oskar heads the finance and projects group in Austria. He advises clients on all aspects of real estate, restructuring law and on all types of restructuring matters, and on mining law matters.

Oskar additionally specialises in insurance law, including insurance supervisory law, general terms and conditions of insurance companies and re-insurance, 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.
NORMAN WISELY

CMS

Norman Wisely is a partner at CMS specialising in oil and gas law. Norman has extensive experience in advising clients on oil and gas matters in the UK and internationally, including leading numerous acquisitions and disposals of UKCS and international offshore and onshore oil and gas assets, advising on oil and gas-related share transactions, on transportation and infrastructure projects, decommissioning and decommissioning security, licensing, production sharing and joint venture matters, and all matters relevant to the exploration and production of hydrocarbons.

Norman is an associate member of the Centre for Energy Law at Aberdeen University, is a member of the Association of International Petroleum Negotiators (AIPN) and is the author of several book chapters on oil and gas acquisitions and disposals.

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 (BA in hotel management, 2000) 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 in Erbil, Iraqi Kurdistan, and covers both central Iraq and the autonomous region of Kurdistan.

JOSE 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 of gross acreage, 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.
Appendix 2

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